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, 2019 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:

529,399,923 Common Shares (as at December 31, 2019).

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.

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 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, 2019, 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, 2019, 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, 2019, including the report of its Independent Auditor 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, 2019, 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, 2019, see Exhibit 99.11 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, 2019, 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, 2019, 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, 2019, 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, 2019, 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 Ms. L. Cillis, Mr. J. Craddock and Mr. T. Goldthorpe 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.metrio.net/indicators/governance/ethical_business_practices/ethical_business_practices_ind

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, 2019, 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, 2019, 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 "off-balance sheet arrangements" (as that term is defined in paragraph 11(ii) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. For a discussion of the Registrant's other off-balance sheet arrangements, see page 19 of the Registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2019, attached as Exhibit 99.3.

TABULAR 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, 2019, filed as Exhibit 99.3 to this Annual Report on Form 40-F, and is incorporated herein by reference.

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 Ms. L. Cillis, Mr. J. Craddock, Mr. T. Goldthorpe and Mr. M. Jackson, 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.metrio.net/indicators/governance/ethical_business_practices/ethical_business_practices_ind. 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, 2019, 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.

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.

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 5, 2020

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, 2019.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2019 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, 2019.
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 GLJ Petroleum Consultants Ltd., Independent Engineers
99.10	Consent of Sproule Associates Limited, Independent Engineers
99.11	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
101.1	The following financial information from the Company's audited annual consolidated financial statements for the year ended December 31, 2019, formatted in XBRL (Extensible Business Reporting Language) and furnished electronically herewith: (1) Consolidated Statements of Operations and Comprehensive Earnings; (2) Consolidated Balance Sheets; (3) Consolidated Statements of Cash Flows; (4) Consolidated Statements of Shareholders' Equity and (5) Notes to Consolidated Financial Statements.

Exhibit 99.1



CRESCENT POINT ENERGY CORP.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2019

Dated March 4, 2020

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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 annual information form 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;
- 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;
- 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 waterflood programs;
- treatment of DRIP and SDP participants if either plan is reinstated;
- the impacts of the *Orphan Well Association v Grant Thornton Ltd.* court decision;
- 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 and the repurchase of Common Shares by the Corporation, including pursuant to its normal course issuer bid;
- supply and demand for oil and natural gas;
- expectations of regulatory changes and implementations and change in 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; 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, 2019, 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, 2019, under the headings "Capital Expenditures", "Liquidity and Capital Resources", "Critical Accounting Estimates", "Risk Factors", "Changes in Accounting Policies" and "Outlook".

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 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; risks and uncertainties related to oil and gas interests and operations on tribal 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 of acquisitions and exploration and development programs and of dispositions and monetization; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; 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; 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.

Operating netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback is calculated on a per boe basis as operating netback plus realized derivative gains and losses. Operating netback and netback are common metrics used in the oil and gas industry and are used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. The calculation of netback 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 securities laws. 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.

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, 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 in all significant respects.

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.

"**AEP**" means Alberta Environment and Parks.

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

"**AIF**" means this annual information form of the Corporation dated March 4, 2020 for the year ended December 31, 2019.

"**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.

"**CPHI**" means Crescent Point Holdings Inc.

"**CPLux**" means Crescent Point Energy Lux S.à r.l.

"**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.

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

"**GLJ**" means GLJ Petroleum Consultants Ltd.

"**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.

"**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, 2019.

"**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.

"**Partnership**" means Crescent Point Resources Partnership, a general partnership formed under the laws of the Province of Alberta, having CPHI 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.

"**Sproule**" means Sproule Associates Limited.

"**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.

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

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

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

In this AIF, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

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	Mcfe	thousand cubic feet of gas equivalent converting one barrel of oil to 6 Mcf of natural gas equivalent
Mbbls	thousand barrels		
NGLs	natural gas liquids		
		MMcf	million cubic feet
		MMcf/d	million cubic feet per day
		MMBTU	million British Thermal Units
		GJ	gigajoule

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
MW	megawatt
MW/h	megawatt per hour
tCO2e	tonnes of carbon dioxide 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, 2019, 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 and natural gas reserves in Western Canada and the United States.

We make regular cash dividends to Shareholders from our net cash flow. Our primary source of cash flow is distributions from the Partnership.

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 CPHI 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.

CPHI

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

CPLux

CPLux is a wholly-owned indirect subsidiary of the Corporation.

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.

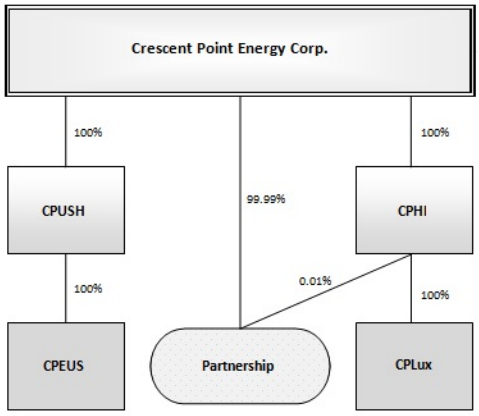
Relationships

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
CPHI	100%	Alberta
Partnership	100%	Alberta
CPUSH	100%	Nevada
CPEUS	100%	Delaware
CPLux	100%	Luxembourg

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 March 4, 2020. 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.

2017

In the first quarter of 2017, Crescent Point completed the acquisition of approximately 8,500 net acres in North Dakota for total cash consideration of US$100.0 million. The acquired lands were contiguous to the Corporation's current acreage.

Crescent Point also acquired approximately 80,000 net acres of undeveloped land in the Uinta Basin in the second quarter of 2017, for total cash consideration of US$72.5 million.

In the second quarter of 2017, the Corporation sold 1,100 boe/d of non-operated conventional assets in Manitoba for total cash consideration of $93.2 million.

On May 24, 2017, Ted Goldthorpe was elected as a director of the Corporation. See "*Additional Information Respecting Crescent Point - Directors and Officers*".

On June 26, 2017, Crescent Point renewed its unsecured, covenant-based credit facilities totaling $3.6 billion. The renewal extended the maturity date of the credit facilities to June 10, 2020. See "*Additional Information Respecting Crescent Point - Long-Term Debt*".

During the third quarter of 2017, the Corporation completed or entered into agreements to dispose of non-core assets representing approximately 3,000 boe/d for total value of over $190 million.

In the fourth quarter of 2017, Crescent Point entered into agreements to dispose of non-core assets for total value of approximately $40 million.

2018

In the second quarter of 2018, Crescent Point completed the disposition of non-core assets mostly in southeast Saskatchewan, for proceeds of approximately $280 million. The assets sold represented operated and non-operated production of approximately 4,800 boe/d.

Early in the second quarter of 2018, the Corporation completed a private placement of senior unsecured, guaranteed notes for total gross proceeds of US$143.5 million and CDN$80.0 million. Three separate series of notes were issued as part of the private placement, with maturities ranging from five to seven years and interest rates ranging from 3.58% to 3.98%. Proceeds from the issuance of the notes were used to repay a portion of the Corporation's outstanding bank debt and other senior guaranteed notes with near-term maturities.

On May 4, 2018, François Langlois was elected as a new director of the Corporation. See " *Additional Information Respecting Crescent Point - Directors and Officers*".

On May 29, 2018, Scott Saxberg stepped down as President and Chief Executive Officer of Crescent Point, and Craig Bryksa was appointed interim President and Chief Executive Officer and to the Board. Mr. Bryksa was subsequently appointed as Crescent Point's President and Chief Executive Officer on September 5, 2018.

On June 19, 2018, Neil Smith, Chief Operating Officer, stepped down as an officer of the Corporation, and Ryan Gritzfeldt was promoted from Vice President, Marketing and Innovation to the position of Chief Operating Officer.

On June 22, 2018, Crescent Point renewed its unsecured credit facilities totaling $3.6 billion with a new maturity date of June 10, 2021.

On September 5, 2018, Robert Heinemann was appointed as the new Chairman of the Board of Directors, replacing Peter Bannister, who has announced his intention to retire from the Board at the Corporation's 2019 annual meeting of shareholders.

2019

On January 25, 2019, the Corporation commenced its NCIB to purchase, for cancellation, up to 38,424,678 Common Shares, or seven percent of the Corporation's public float, as at January 14, 2019. The NCIB expired on January 24, 2020. 26,238,600 Common Shares were purchased under the NCIB.

On February 19, 2019, Crescent Point announced the appointment of John P. Dielwart to the Board, effective March 7, 2019. See " *Additional Information Respecting Crescent Point - Directors and Officers".*

On June 14, 2019, James Craddock and Jennifer Koury were appointed to the Board. See " *Additional Information Respecting Crescent Point - Directors and Officers*".

In September 2019, Crescent Point disposed of certain conventional assets in southeast Saskatchewan for consideration of $196.9 million, representing approximately 7,000 boe/d of production.

On October 18, 2019, Crescent Point sold the entirety of its Utah assets for approximately $700 million.

On October 25, 2019, Crescent Point elected to reduce its covenant-based credit facilities from $3.6 billion to $3.0 billion and extended the maturity dates to October 2023.

On October 30, 2019, Barbara Munroe was appointed as the new Chair of the Board, replacing Robert Heinemann, who retired from the Board.

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.

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 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 CPHI, 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 and natural gas reserves and Proved plus Probable (as defined herein) crude oil 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 prima ry sources of cash flow are distributions from the Partnership. During the year ended December 31, 2019, we paid quarterly dividends of $0.01 per Common Share. See "*Dividends*".

Strategy

We strive to enhance shareholder returns by cost effectively developing a focused asset base in a responsible and sustainable manner. Through the development of our assets, we aim to create sustainable, profitable and returns-based growth in reserves, production and cash flow.

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, infill and step-out wells, multi-stage fracture stimulation of horizontal wells, re-completion of existing wells and secondary recovery techniques such as 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 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 fuels;
(i) the effect of energy conservation measures and government regulations; and
(j) U.S. and Canada tax policy.

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 payment of dividends to Shareholders.

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 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. 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 and benchmark natural gas prices are hedged using financial AECO-based instruments transacted in Canadian dollars. Total financial oil and gas hedges in 2019 amounted to approximately 47% of annual production, net of royalties, consisting of approximately 50% of annual liquids production and approximately 22% of annual natural gas production, net of royalties. The Corporation recorded a realized derivative loss on crude oil and natural gas hedge contracts of $43.4 million in 2019.

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 2019, approximately 18,300 bbls/d of liquids production was contracted with fixed price differentials off WTI.

Refer to the annual financial statements for our commitments under all hedging agreements as at December 31, 2019.

In addition to hedging benchmark crude oil and natural gas prices with financial instruments, we also mitigate crude oil basis risk by delivering a portion of our crude oil production into diversified refinery markets using rail transportation. Crescent Point operates two railcar loading facilities, serving its key producing areas of southeast Saskatchewan and southwest Saskatchewan. Crude oil 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 at the refinery gate. By utilizing rail transportation, we have been able to access refining markets over the past several years that are not pipeline connected to western Canada, which helps diversify price and market risk.

We mitigate credit risk by having a well-diversified marketing portfolio for crude oil and natural gas. Credit risk associated with the Corporation's portfolio of physical crude oil and natural gas sales and with the Corporation's commodity 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 107 purchasers and its financial hedging portfolio consists of 15 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 obtains financial assurances such as parental guarantees, letters of credit and third party credit insurance. Including these assurances, approximately 95% 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, Manitoba and British Columbia. Approximately 72% of our liquids volumes are sold in Saskatchewan, 22% in the U.S., 6% in Alberta, and less than 1% in Manitoba and British Columbia. Approximately 62% of our natural gas volumes are sold in Saskatchewan, 25% in the United States, 12% in Alberta and less than 1% in Manitoba and British Columbia.

For 2019, our commodity production mix was approximately 91% crude oil and NGLs and 9% natural gas.

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

For Year Ended	Crude Oil and NGLs	Natural Gas
2019	97%	3%
2018	98%	2%
2017	97%	3%

Competition

We actively compete for reserve acquisitions, exploration leases, licences 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 explora tion 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.

Personnel

As of December 31, 2019, the Corporation had 864 permanent employees: 393 employees at the head office in Calgary, 50 employees at the Denver office, 407 field employees in Canada and 14 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 GLJ and Sproule with an effective date of December 31, 2019, and contained in the consolidated report of GLJ dated February 14, 2020 (the "**Crescent Point Reserve Report**"). The tables below are a combined summary

of our crude oil, NGL 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 Sproule's December 31, 2019 forecast price and cost assumptions. GLJ evaluated approximately 40% of the assigned total Proved plus Probable reserves and 29% of the total Proved plus Probable value discounted at 10%. Sproule evaluated approximately 60% of the assigned total Proved plus Probable reserves and 71% of the total Proved plus Probable value discounted at 10%. Sproule evaluated a majority of the southeast Saskatchewan assets including the Viewfield Bakken and Flat Lake Torquay properties, as well as southwest Saskatchewan assets including the Shaunavon and Saskatchewan Viking properties. Sproule evaluated their portion of the reserves using the Sproule forecast price and cost escalation assumptions. GLJ evaluated the Corporation's Alberta and British Columbia assets, as well as a portion of the assets in southeast Saskatchewan. GLJ also performed the evaluation of the Corporation's U.S. assets in North Dakota and Montana. These assets were all evaluated using the Sproule forecast price and cost escalation assumptions. GLJ prepared the total Crescent Point Reserve Report by consolidating the GLJ Canadian and U.S. evaluated properties with the Sproule evaluation using the Sproule pricing and cost escalation assumptions. The tables below summarize the data contained in the Crescent Point Reserve Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

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 for those entities assigned reserves by GLJ and Sproule. 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 GLJ and Sproule 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. New legislation that was 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 anticipated negative financial impact of carbon emission costs to Total Proved plus Probable reserves evaluation as of December 31, 2019 as a result of the implementation of these new programs is $9.5 MM discounted at 10% before tax, with no impact on reserve level bookings.

The Crescent Point Reserve Report is based on certain factual data supplied by Crescent Point as well as GLJ and Sproule'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 (except for certain information residing in the public domain) were supplied by the Corporation to GLJ and Sproule, and were accepted without any further investigation. GLJ and Sproule 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	71,484	63,986	24,175	20,066	116,743	109,581	36,450	33,775	91,829	85,575	60,040	55,970	274,163	250,998
United States	—	—	—	—	21,059	17,057	6,335	5,131	19,664	15,926	—	—	30,672	24,843
Total	71,484	63,986	24,175	20,066	137,803	126,638	42,785	38,906	111,492	101,501	60,040	55,970	304,836	275,841
Proved Developed Non-Producing														
Canada	1,341	1,246	1,979	1,731	1,313	1,209	618	570	1,216	1,060	1,297	1,073	5,669	5,111
United States	—	—	—	—	6	5	—	—	3	2	—	—	6	5
Total	1,341	1,246	1,979	1,731	1,318	1,213	618	570	1,219	1,062	1,297	1,073	5,675	5,116
Proved Undeveloped														
Canada	28,122	26,013	1,645	1,419	58,096	55,040	13,239	12,365	45,407	41,860	10,750	9,743	110,462	103,439
United States	—	—	—	—	37,825	30,638	6,421	5,201	21,206	17,177	—	—	47,780	38,702
Total	28,122	26,013	1,645	1,419	95,922	85,679	19,659	17,566	66,614	59,038	10,750	9,743	158,242	142,141
Total Proved														
Canada	100,947	91,245	27,799	23,216	176,152	165,831	50,306	46,710	138,452	128,496	72,086	66,787	390,294	359,548
United States	—	—	—	—	58,890	47,700	12,756	10,332	40,873	33,105	—	—	78,459	63,550
Total	100,947	91,245	27,799	23,216	235,043	213,531	63,062	57,042	179,325	161,601	72,086	66,787	468,753	423,098
Total Probable														
Canada	58,348	52,860	6,894	5,508	112,932	105,681	26,302	24,511	80,222	74,407	33,640	31,003	223,452	206,129
United States	—	—	—	—	37,120	30,086	7,013	5,684	22,942	18,598	—	—	47,956	38,870
Total	58,348	52,860	6,894	5,508	150,052	135,767	33,315	30,195	103,163	93,005	33,640	31,003	271,409	244,998
Total Proved Plus Probable														
Canada	159,295	144,104	34,693	28,724	289,084	271,512	76,608	71,221	218,674	202,903	105,726	97,790	613,747	565,677
United States	—	—	—	—	96,010	77,786	19,769	16,016	63,815	51,703	—	—	126,415	102,419
Total	159,295	144,104	34,693	28,724	385,094	349,298	96,377	87,237	282,488	254,606	105,726	97,790	740,161	668,096

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	8,406	6,697	5,922	5,500	4,681	4,096	8,093	6,526	5,801	5,402	4,624	4,060
United States	977	735	640	590	497	433	944	717	627	579	490	428
Total	9,383	7,432	6,563	6,090	5,179	4,529	9,037	7,242	6,428	5,982	5,114	4,489
Proved Developed Non-Producing												
Canada	257	177	151	138	115	98	196	140	122	114	99	88
United States	—	—	—	—	—	—	—	—	—	—	—	—
Total	257	177	151	138	115	99	197	140	123	114	99	88
Proved Undeveloped												
Canada	2,623	1,808	1,461	1,272	911	659	1,896	1,309	1,054	916	648	461
United States	772	368	226	156	37	(33)	709	334	201	136	25	(41)
Total	3,395	2,176	1,687	1,428	948	626	2,605	1,643	1,256	1,052	673	420
Total Proved												
Canada	11,287	8,682	7,535	6,910	5,707	4,854	10,185	7,974	6,978	6,432	5,371	4,609
United States	1,749	1,103	866	746	534	400	1,653	1,051	828	716	515	388
Total	13,036	9,785	8,401	7,657	6,242	5,254	11,838	9,025	7,806	7,148	5,886	4,997
Total Probable												
Canada	9,319	5,298	4,082	3,510	2,549	1,965	6,898	3,903	2,999	2,576	1,869	1,444
United States	1,918	999	738	621	432	324	1,648	891	668	566	400	302
Total	11,238	6,297	4,820	4,130	2,981	2,289	8,546	4,794	3,667	3,142	2,269	1,746
Total Proved Plus Probable												
Canada	20,606	13,980	11,617	10,420	8,256	6,819	17,083	11,877	9,977	9,008	7,240	6,053
United States	3,667	2,102	1,604	1,367	967	724	3,301	1,941	1,496	1,282	915	690
Total	24,273	16,082	13,221	11,787	9,223	7,543	20,384	13,818	11,474	10,289	8,155	6,743

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	27,873	2,770	9,657	2,393	1,767	11,287	1,102	10,185
United States	5,938	1,559	1,546	1,048	36	1,749	96	1,653
Total	33,811	4,328	11,203	3,441	1,803	13,036	1,197	11,838
Proved Plus Probable								
Canada	46,465	4,508	15,515	3,862	1,974	20,606	3,523	17,083
United States	10,331	2,714	2,671	1,232	47	3,667	366	3,301
Total	56,796	7,222	18,185	5,094	2,021	24,273	3,889	20,384

Notes:
(1) Numbers may not add due to rounding.
(2) Saskatchewan Capital Resource Surcharge, as well as Ad Valorem, and Severance payable in the United States have been included under the royalties and burdens column.
(3) Abandonment and Reclamation costs now include active costs from wells and locations included in the Crescent Point Reserve Report as well as inactive costs including suspended wells, pipelines and facilities, as specified in COGEH update of October 2019.

In 2018, the Crescent Point Reserve Report included abandonment and reclamation costs for active wells and locations only. As recommended in the October 2019 COGEH updated guidance, the Corporation has now also included abandonment, decommissioning and reclamation costs for all inactive assets including non-producing and suspended wells, facilities and pipelines. The impact on the Crescent Point Reserve Report from these additional burdens on total Proved plus Probable reserves is estimated at $261 million of value discounted at 10%, which will differ from the discounted values carried in our financial reporting, due to differences in abandonment activity timing and different inflation and discount values.

Future Net Revenue by Production Type (1)

	Future Net Revenue Before Income Taxes(6) (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved				
CANADA				
Light and Medium Crude Oil (2)	1,916	27.7	18.41	3.07
Heavy Crude Oil(2)	376	5.4	16.09	2.68
Tight Oil(4)	4,585	66.3	20.71	3.45
Natural Gas Liquids	—	—	—	—
Shale Gas (5)	—	—	—	—
Conventional Natural Gas (3)	33	0.5	3.11	0.52
Total Canada	6,910	100	19.22	3.20
UNITED STATES				
Light and Medium Crude Oil (2)	—	—	—	—
Heavy Crude Oil(2)	—	—	—	—
Tight Oil(4)	746	100	11.74	1.96
Natural Gas Liquids	—	—	—	—
Shale Gas (3)	—	—	—	—
Conventional Natural Gas (3)	—	—	—	—
Total United States	746	100	11.74	1.96
TOTAL				
Light and Medium Crude Oil (2)	1,916	25.0	18.41	3.07
Heavy Crude Oil(2)	376	4.9	16.09	2.68
Tight Oil(4)	5,331	69.6	18.71	3.12
Natural Gas Liquids	—	—	—	—
Shale Gas (3)(5)	—	—	—	—
Conventional Natural Gas (3)	33	0.4	3.11	0.52
Total Proved	7,657	100	18.10	3.02

Notes:
(1) Numbers may not add due to rounding.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas.
(4) Including solution gas (categorized as “Shale Gas”) and other by-products.
(5) Volumes of Shale Natural Gas have been included in “Tight Oil” as it is solution gas relating to oil production.
(6) 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.

	Future Net Revenue Before Income Taxes(6) (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved Plus Probable				
CANADA				
Light and Medium Crude Oil(2)	2,961	28.4	17.70	2.95
Heavy Crude Oil()	456	4.4	15.76	2.63
Tight Oil(4)	6,965	66.8	19.53	3.26
Natural Gas Liquids	—	—	—	—
Shale Gas(5)	—	—	—	—
Conventional Natural Gas(3)	39	0.4	3.01	0.50
Total Canada	10,420	100	18.42	3.07
UNITED STATES				
Light and Medium Crude Oil(2)	—	—	—	—
Heavy Crude Oil(2)	—	—	—	—
Tight Oil(4)	1,367	100	13.35	2.22
Natural Gas Liquids	—	—	—	—
Shale Gas(3)	—	—	—	—
Conventional Natural Gas(3)	—	—	—	—
Total United States	1,367	100	13.35	2.22
TOTAL				
Light and Medium Crude Oil(2)	2,961	25.1	17.70	2.95
Heavy Crude Oil(2)	456	3.9	15.76	2.63
Tight Oil(4)	8,332	70.7	18.15	3.03
Natural Gas Liquids	—	—	—	—
Shale Gas(3)(5)	—	—	—	—
Conventional Natural Gas(3)	39	0.3	3.01	0.50
Total Proved Plus Probable	11,787	100	17.64	2.94

Notes:
(1) Numbers may not add due to rounding.
(2) Including solution gas and other by-products.
(3) Including by-products, but excluding solution gas.
(4) Including solution gas (categorized as “Shale Gas”) and other by-products.
(5) Volumes of Shale Natural Gas have been included in “Tight Oil” as it is solution gas relating to oil production.
(6) 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.

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 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 defence, 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;

(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, licence 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

GLJ and Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2019 in estimating our reserves data using forecast prices and costs.

Year	Conventional Natural Gas		Crude Oil		NGLs					
	Henry Hub NYMEX *($US/MMBTU)*	AECO/NIT Spot *($Cdn/MMBTU)*	WTI at Cushing Oklahoma *($US/bbl)*	Edmonton *($Cdn/bbl)*	Pentanes Plus Edmonton *($Cdn/bbl)*	Butanes Edmonton *($Cdn/bbl)*	Propane Edmonton *($Cdn/bbl)*	Operating Cost Inflation Rate *(%/yr)*	Capital Cost Inflation Rate *(%/yr)*	Exchange Rate *($US/$Cdn)*
Forecast										
2020	2.80	2.04	61.00	73.84	76.32	37.72	25.07	0.0%	0.0%	0.760
2021	3.00	2.27	65.00	78.51	80.52	43.90	31.84	1.0%	1.0%	0.770
2022	3.25	2.81	67.00	78.73	80.00	47.74	32.43	2.0%	2.0%	0.800
2023	3.32	2.89	68.34	80.30	81.68	48.69	33.26	2.0%	2.0%	0.800
2024	3.38	2.98	69.71	81.91	83.38	49.67	34.12	2.0%	2.0%	0.800
2025	3.45	3.06	71.10	83.54	85.13	50.66	34.99	2.0%	2.0%	0.800
2026	3.52	3.15	72.52	85.21	86.90	51.67	35.88	2.0%	2.0%	0.800
2027	3.59	3.24	73.97	86.92	88.72	52.71	36.78	2.0%	2.0%	0.800
2028	3.66	3.33	75.45	88.66	90.57	53.76	37.71	2.0%	2.0%	0.800
2029	3.73	3.42	76.96	90.43	92.45	54.84	38.65	2.0%	2.0%	0.800
2030	3.81	3.51	78.50	92.24	94.38	55.93	39.61	2.0%	2.0%	0.800
2031+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0%	2.0%	0.800

For the year ended December 31, 2019, the average realized sales prices before hedging were $66.50/bbl for light and medium crude oil, $60.95/bbl for heavy crude oil, $67.67/bbl for tight oil, $19.94/bbl for NGLs, $2.87/mcf for shale gas and $2.29/mcf for conventional natural gas.

Reconciliations of Changes in Reserves (1)

The following table sets forth a reconciliation of the Corporation's Company Gross reserves by total Proved, total Probable and total Proved plus Probable reserves as at December 31, 2019 against such reserves as at December 31, 2018 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, 2018	127,356	71,928	199,284	29,015	7,903	36,918	219,734	130,667	350,400	59,824	31,789	91,613
Discoveries	85	29	114	—	—	—	494	171	664	27	9	36
Extensions and Improved Recovery (2)	3,658	2,016	5,674	133	10	143	11,669	8,865	20,534	1,282	875	2,156
Technical Revisions (4)	(638)	(5,633)	(6,270)	670	(951)	(281)	(21,578)	(20,512)	(42,090)	(1,885)	(4,122)	(6,007)
Acquisitions	2,403	590	2,993	—	—	—	2	47	49	—	17	17
Dispositions (5)	(18,827)	(9,959)	(28,786)	—	—	—	(9,186)	(6,707)	(15,893)	(2,321)	(2,080)	(4,401)
Economic Factors	(2,107)	(622)	(2,729)	(285)	(69)	(354)	(1,761)	402	(1,360)	(691)	(186)	(877)
Production (7)	(10,984)	—	(10,984)	(1,733)	—	(1,733)	(23,220)	—	(23,220)	(5,931)	—	(5,931)
December 31, 2019	100,947	58,348	159,295	27,799	6,894	34,693	176,152	112,932	289,084	50,306	26,302	76,608

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, 2018	178,930	105,297	284,228	85,259	39,953	125,212	479,960	266,495	746,455
Discoveries	518	179	698	—	—	—	692	239	931
Extensions and Improved Recovery (2)	7,787	6,216	14,003	572	442	1,014	18,134	12,876	31,010
Technical Revisions (4)	(8,946)	(12,913)	(21,858)	(2,100)	(4,342)	(6,442)	(25,271)	(34,093)	(59,365)
Acquisitions	1	44	45	1	1	1	2,406	661	3,067
Dispositions (5)	(21,651)	(18,399)	(40,050)	(544)	(1,032)	(1,576)	(34,033)	(21,985)	(56,018)
Economic Factors	(453)	(203)	(656)	(3,858)	(1,382)	(5,240)	(5,563)	(740)	(6,302)
Production (7)	(17,735)	—	(17,735)	(7,243)	—	(7,243)	(46,031)	—	(46,031)
December 31, 2019	138,452	80,222	218,674	72,086	33,640	105,726	390,294	223,452	613,747

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, 2018	68	31	99	—	—	—	105,613	78,820	184,433	15,976	10,513	26,489
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (3)	—	—	—	—	—	—	11,517	5,987	17,504	2,090	1,084	3,174
Technical Revisions (4)	(11)	(4)	(14)	—	—	—	2,726	(1,465)	1,262	1,668	(611)	1,057
Acquisitions	—	—	—	—	—	—	376	218	595	74	43	117
Dispositions (6)	(58)	(27)	(85)	—	—	—	(50,875)	(44,394)	(95,268)	(5,335)	(3,618)	(8,954)
Economic Factors	—	—	—	—	—	—	(336)	(2,047)	(2,383)	(74)	(397)	(471)
Production (7)	—	—	—	—	—	—	(10,132)	—	(10,132)	(1,642)	—	(1,642)
December 31, 2019	—	—	—	—	—	—	58,890	37,120	96,010	12,756	7,013	19,769

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, 2018	107,585	73,380	180,965	5	2	8	139,589	101,594	241,183
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (3)	6,401	3,338	9,739	—	—	—	14,673	7,628	22,301
Technical Revisions (5)	8,260	663	8,923	(4)	(2)	(6)	5,759	(1,969)	3,790
Acquisitions	214	125	339	—	—	—	486	282	769
Dispositions (6)	(72,919)	(53,414)	(126,333)	(1)	(1)	(2)	(68,421)	(56,942)	(125,363)
Economic Factors	(215)	(1,150)	(1,365)	—	—	—	(446)	(2,636)	(3,082)
Production (7)	(8,453)	—	(8,453)	—	—	—	(13,183)	—	(13,183)
December 31, 2019	40,873	22,942	63,815	—	—	—	78,459	47,956	126,415

TOTAL	Light and Medium Crude Oil *(Mbbls)*			Heavy Crude Oil *(Mbbls)*			Tight Oil (4) *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2018	127,424	71,959	199,383	29,015	7,903	36,918	325,347	209,486	534,833	75,800	42,302	118,102
Discoveries	85	29	114	—	—	—	494	171	664	27	9	36
Extensions and Improved Recovery (2) (3)	3,658	2,016	5,674	133	10	143	23,186	14,852	38,038	3,371	1,959	5,330
Technical Revisions (4)	(648)	(5,637)	(6,285)	670	(951)	(281)	(18,852)	(21,977)	(40,828)	(217)	(4,733)	(4,950)
Acquisitions	2,403	590	2,993	—	—	—	379	266	644	74	60	134
Dispositions (5) (6)	(18,884)	(9,986)	(28,871)	—	—	—	(60,061)	(51,101)	(111,162)	(7,656)	(5,699)	(13,355)
Economic Factors	(2,107)	(622)	(2,729)	(285)	(69)	(354)	(2,098)	(1,646)	(3,743)	(765)	(583)	(1,348)
Production (7)	(10,984)	—	(10,984)	(1,733)	—	(1,733)	(33,352)	—	(33,352)	(7,573)	—	(7,573)
December 31, 2019	100,947	58,348	159,295	27,799	6,894	34,693	235,043	150,052	385,094	63,062	33,315	96,377

TOTAL	Shale Gas (5) (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, 2018	286,515	178,677	465,193	85,264	39,955	125,219	619,549	368,089	987,638
Discoveries	518	179	698	—	—	—	692	239	931
Extensions and Improved Recovery (2) (3)	14,188	9,554	23,743	572	442	1,014	32,808	20,503	53,311
Technical Revisions (4)	(686)	(12,250)	(12,936)	(2,104)	(4,344)	(6,448)	(19,512)	(36,063)	(55,574)
Acquisitions	216	168	384	1	1	1	2,892	944	3,836
Dispositions (5) (6)	(94,570)	(71,813)	(166,383)	(546)	(1,032)	(1,578)	(102,454)	(78,927)	(181,381)
Economic Factors	(668)	(1,354)	(2,021)	(3,858)	(1,382)	(5,240)	(6,009)	(3,376)	(9,385)
Production (7)	(26,188)	—	(26,188)	(7,243)	—	(7,243)	(59,214)	—	(59,214)
December 31, 2019	179,325	103,163	282,488	72,086	33,640	105,726	468,753	271,409	740,161

Notes:
(1) Numbers may not add due to rounding.
(2) The Corporation's Canadian development strategy in 2019 focused on in-fill and development drilling, mostly in the Viewfield Bakken and Flat Lake Torquay resource plays in southeast Saskatchewan as well as the Shaunavon area.
(3) The Corporation's United States development strategy in 2019 focused on in-fill and development drilling, mostly in the Bakken and Three Forks resource plays in Williams, North Dakota.
(4) Negative technical revisions on Probable volumes are reflective of reserve volumes being transferred to Proven reserves categories as reserve confidence grows and locations are converted from Probable reserves to Proved plus Probable reserves, through either offset drilling increasing confidence in location bookings, or actual conversion of the location to developed (well) reserves.
Performance-based negative revisions were observed on existing primary (non-waterflood) Tight Oil assets including the Viewfield Bakken, Flat Lake Torquay and the Shaunavon area resource assets, representing a large portion of the revisions in this category. These revisions were primarily due to a reassessment of the resource basins, which resulted in recognition of performance deviations from early forecasts. The reassessment of the Corporation's producing assets has also resulted in a corresponding negative technical revision on some of the associated area locations, which has in turn been reflected in the Corporation's reserves reported. Additionally, these technical revisions impacted the corresponding Shale Gas and NGL reserves.
Increased gas-oil ratios from early forecasts in Williams, North Dakota resulted in increases of both Shale Gas and NGL volumes.
Light and Medium volumes realized negative technical revisions in Proved as well as Proved plus Probable reserves, spread across several plays including Flat Lake Ratcliffe, Provost Viking and Turner Valley Rundle.
(5) The Corporation's southeast Saskatchewan Light and Medium Crude Oil disposition program represents the majority of values presented. These dispositions closed in the third quarter of 2019.
(6) The Corporation's disposition of all assets in the Uinta basin of Utah represent most of these volumes, which closed on October 18, 2019.
(7) The Corporation produced an average of 126,113 boe per day in Canada, 36,117 boe per day in the United States for a total of 162,230 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, lease-line 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 physical ability, to completely execute on the entire portfolio of booked opportunities within two years, however approximately 50% of the development spending occurs within this timeframe.

The development of these reserves have been based on recent and current capital activity levels, with no material deferrals of development opportunities beyond these normal budgetary constraints. The majority of these reserves are planned to be on stream within a three-year timeframe, which represents approximately 81% of the net undeveloped location count, as well as 74% of the net total future development capital. These development activities are directed mostly to the Corporation's core focus areas of Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Three Forks play in the U.S.

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
2017	1,745	37,676	—	1,991	24,359	140,487	3,968	24,311	18,569	128,064	118	18,679	33,187	228,922
2018	7,706	33,819	—	1,771	27,622	138,096	3,963	25,357	17,358	119,169	2,390	12,882	42,582	221,051
2019	3,829	28,122	—	1,645	16,482	95,922	2,144	19,659	10,262	66,614	169	10,750	24,194	158,242

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-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 on stream within a three-year timeframe, representing approximately 69% of the net undeveloped location count, as well as 64% of the total net future development costs. Other than for normal budgetary constraints, the Corporation has no plans to defer development of Probable Undeveloped reserves. 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 Viewfield Bakken, Flat Lake Torquay and Shaunavon resource plays in Canada and the North Dakota Three Forks and Bakken plays in the U.S. The Corporation’s Swan Hills area development program is scheduled over ten years to match current development plans.

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
2017	2,184	52,846	—	1,444	30,640	129,585	4,774	22,570	19,996	105,133	614	28,756	41,033	228,760
2018	5,594	43,709	—	1,403	28,892	133,715	4,220	24,636	24,749	105,633	1,918	21,538	43,151	224,658
2019	1,990	33,955	—	1,161	12,405	91,941	1,522	19,066	8,090	58,496	319	18,126	17,318	158,893

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 GLJ and Sproule, each 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
2020	614	698	184	237	798	935
2021	621	841	287	339	907	1,180
2022	613	871	217	268	831	1,139
2023	398	781	157	185	555	966
2024	116	366	203	203	319	569
2025	5	70	—	—	5	70
2026	3	49	—	—	3	49
2027	2	60	—	—	2	60
2028	7	47	—	—	7	47
2029	3	59	—	—	3	59
2030	1	2	—	—	1	2
2031	1	2	—	—	1	2
Subtotal(1)	2,383	3,845	1,048	1,232	3,431	5,077
Remainder	10	17	—	—	10	17
Total(1)	2,393	3,862	1,048	1,232	3,441	5,094
10% Discounted	1,986	3,031	839	995	2,825	4,025

Notes:
(1) Numbers may not add due to rounding.
(2) In Canada, the Corporation drilled 450 (420.1 net) wells in 2019. For 2020, the Corporation has budgeted the drilling of 457 (426.0 net) wells. 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 by the qualified reserve evaluators have a similar drilling timing as the Corporation's long-term development plan. As a result, the total Proved and almost all of the total Proved plus Probable drilling schedule occur within a five year period. The remaining capital expenditures beyond the five year period essentially relate to maintenance capital on existing wells and assets. The development program in Swan Hills, which represents less than five percent of the Corporation's total net Proved plus Probable location count, is scheduled over ten years. The timing of this maintenance capital may vary between Proved and Proved plus Probable reserve categories, due to such factors as longer forecast lives on Proved plus Probable versus Proved reserves.
(3) In the United States, Crescent Point drilled 60 (45.7 net) wells in 2019, while in 2020, the Corporation is budgeting the drilling of 24 (20.1 net) wells. As in Canada, a large number of Proved as well as Proved plus Probable locations have been booked. The scheduling of locations by the qualified reserve evaluators have a similar drilling timing as the Corporation's long-term development plan. As a result, both the total Proved and total Proved plus Probable drilling schedule occur within a five year period.

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 regions, properties, plants, facilities and installations 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. The Corporation holds no interests in any plants, facilities or installations that are significant beyond normal oil and gas operating practices, in major properties described below, or in less material producing areas. 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, 2019.

The Corporation has disposed of gas infrastructure assets in Saskatchewan for total cash consideration of $500 million, as of January 20, 2020. Disposed assets include nine natural gas gathering and processing facilities and two gas sales pipelines. The disposition of these assets was not reflected in the Crescent Point Reserve Report as of December 31, 2019. The impact of the disposition will be an increase in observed operating costs in those specific areas through the assignment of third-party processing fees charged against volumes produced. This impact has been estimated pro-forma as $314.5 million at a discounted rate of 10% on total Proved plus Probable reserves.

Viewfield Bakken Resource

Crescent Point is the largest Canadian producer across the Viewfield Bakken resource area in southeastern Saskatchewan, with 2019 average production of approximately 41,900 boe per day. Production is a high quality light oil and is exploited using multi-fractured horizontal wells. The core area of the resource base is almost all at 100% working interest rights, most of which has now been unitized. The Corporation is now in the process of planning and proposing additional units in the Bakken resource play to initiate additional waterflood projects. The Bakken play in this area has continued to be a major driver in the Corporation's portfolio, maturing from early development and delineation drilling activities to the current focus on reservoir development through infill drilling, pool extensions and waterflood advancements.

Crescent Point spent $244 million, representing approximately 19% of its 2019 capital development program, on the Viewfield Bakken resource area including drilling 127 (120.9 net) additional oil wells. The Corporation also continued to focus on waterflood development expansion.

At year end 2019, the Corporation's total Proved plus Probable reserves in the Viewfield Bakken area were 208.6 MMboe, with 610 (568.0 net) locations booked to these reserves. This represents approximately 28% of the Corporation's total Proved plus Probable reserves. Both the Total Proved as well as the Total Proved plus Probable locations are expected to be developed within five years based on recent and current planned development rates in the area. Of the Total Proved locations, 83% are to be drilled within the first three years.

In 2020, Crescent Point has allocated 21% of the Corporation's capital budget to development of the Viewfield Bakken resource play, primarily focused on in-fill 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 Upper Shaunavon resource and conventional zones, as well as the Lower Shaunavon resource zone exist both individually and together as stratified pools. The conventional portions of the Upper Shaunavon have been under development for several decades, having originally been developed using vertical wells, and, more recently, using horizontal wells. Both waterfloods and enhanced recovery techniques are being used to increase recovery factors in these pools. The tight oil Upper and Lower resource plays have been developed using fracture stimulated horizontal wells and, more recently, by advancing waterflood techniques that have continued to grow production in the area. In 2019, Crescent Point's production averaged approximately 26,400 boe per day in the area.

In 2019, the Corporation continued to develop the Shaunavon area by drilling 118 (115.7 net) wells, and waterflood optimization to enhance recoveries. Total capital spent on these activities in 2019 was $225 million, representing approximately 18% of the Corporation's capital budget.

As of year end 2019, Crescent Point has booked total Proved plus Probable reserves of 130.4 MMboe in the Shaunavon area, representing approximately 18% of the total Proved plus Probable reserves. The Corporation has 652 (635.8 net) locations booked to total Proved plus Probable reserves as of year end 2019. Crescent Point expects to fully develop this location inventory within five years, with 84% of the Total Proved locations being developed in three years.

In 2020, Crescent Point has allocated 23% of the Corporation's capital budget to development of the Shaunavon area. The Corporation plans to continue to advance waterflood optimization in the Lower and Upper Shaunavon zones, as well as advance enhanced oil recovery projects in conventional areas within the area.

Flat Lake Area

The Flat Lake area is situated directly north of the U.S. border in southeastern Saskatchewan, where the Corporation is developing the Bakken and Torquay resource plays, as well as the conventional Ratcliffe (Oungre) play, all with horizontal wells. Production in the area averaged approximately 19,800 boe per day in 2019. The Corporation's focus in the Ratcliffe play has been development drilling, followed by implementation of coordinated waterfloods to improve recoveries.

The Corporation spent $252 million, representing 20% of its 2019 capital program, mostly on the Torquay and Ratcliffe plays in Flat Lake including drilling 92 (88.9 net) wells. The Corporation also continued to focus on waterflood development and facility enhancements during the year.

At year end 2019, the Corporation's total Proved plus Probable reserves in the Flat Lake area were 63.8 MMboe, representing approximately 9% of the Corporation's total reserves in this category, a reduction from year end 2018 primarily due to asset dispositions that closed during the year. Included in these reserve volume bookings were 297 (290.3 net) locations. It is expected all the Total Proved locations will be developed within four years, while all Total Proved plus Probable locations will be developed in five years.

In 2020, Crescent Point has allocated 15% of the Corporation's capital budget to the development of the Torquay and Ratcliffe plays. Where possible, the Corporation has started developing the Torquay assets using two mile horizontal wells. As this drilling occurs, prior one mile location bookings are converted to the actual drilled two mile wells. This program is designed to expand and diversify our asset base, expand the potential for waterflood implementation and further develop our drilling inventory.

North Dakota

The Corporation is developing both the Three Forks and Bakken resource plays in North Dakota. Production is a high quality light oil and is developed using multi-fractured horizontal wells, with 2019 average working interest production rates of approximately 19,900 boe per day.

In North Dakota, the Corporation spent $253 million representing 20% of its 2019 capital program, drilling 37 (34.0 net) horizontal wells focusing on pad drilling these assets.

At year end 2019, the Corporation's Total Proved plus Probable reserves in North Dakota were 126.4 MMboe, with 200 (154.7 net) locations booked, representing approximately 17% 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 all be developed within five years, with 70% of Total Proved locations being developed within three years.

In 2020, Crescent Point has allocated 22% of the Corporation's capital budget to developing the Three Forks and Bakken resource plays in North Dakota.

Oil and Gas Wells

Producing Wells				
Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	8,722	7,347	371	125
Alberta	491	406	322	216
Manitoba	1	—	—	—
British Columbia	9	6	—	—
TOTAL CANADA	9,223	7,759	693	341
U.S.				
North Dakota	171	127	—	—
Montana	1	—	—	—
TOTAL U.S.	172	127	—	—
Total	9,395	7,886	693	341

Non-Producing Wells				
Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	4,305	3,521	489	352
Alberta	393	273	194	152
Manitoba	—	—	—	—
British Columbia	—	—	1	1
TOTAL CANADA	4,698	3,794	684	505
U.S.				
North Dakota	1	1	—	—
Montana	—	—	—	—
TOTAL U.S.	1	1	—	—
Total	4,699	3,795	684	505

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

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.

Non-producing reserves represent only 1.2% of the Total Proved reserve category, and 1.3% of the Total Proved plus Probable reserve category. Wells in the non-producing category exist across most of the Corporation’s areas and mostly represent wells awaiting final preparation for production, and wells with secondary producing zones that continue to produce out of the primary zone.

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, 2019		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
CANADA			
Alberta	544,867	486,226	109,846
Saskatchewan	760,546	682,465	88,020
Manitoba	—	—	—
British Columbia	30,610	18,429	—
Total	1,336,023	1,187,120	197,866
U.S.			
Montana	—	—	—
North Dakota	24,897	21,057	990
Total	24,897	21,057	990
Total	1,360,920	1,208,177	198,856

The Corporation has no 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, 2019, in each of Canada and the United States.

	Development Wells		Exploration Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	444	415	3	3	447	418
Natural Gas wells	—	—	—	—	—	—
Service wells	3	3	—	—	3	3
Stratigraphic test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total (1)	447	418	3	3	450	421

	Development Wells		Exploration Wells (2) (3)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	53	39	6	6	59	45
Natural Gas wells	—	—	—	—	—	—
Service wells	1	1	—	—	1	1
Stratigraphic Test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total (1)	54	40	6	6	60	46

Notes:
(1) Numbers may not add due to rounding.
(2) Exploration wells in this grouping are based on the well licence classification at the time of drilling.
(3) Exploration wells in the U.S. were part of the Utah disposition, therefore, are not included in reserve volumes for 2019.

For details on important exploration and development activities during 2019, 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 $10.7 billion at December 31, 2019 to shelter future taxable income. Based on this pool balance and forecast cash flows using forward benchmark prices in effect on the date of this AIF, with the Corporation's development capital plans, Crescent Point does not expect to be taxable in the next five years.

Costs Incurred(1)

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2019. The total capital costs were approximately $1.3 billion in 2019.

($ millions)	Acquisition Costs (2)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	0.6	—	16.1	883.4
U.S.	8.5	7.3	19.1	349.0
Total	9.1	7.3	35.2	1,232.4

Notes:
(1) Costs incurred exclude capitalized administration.
(2) Excludes disposition proceeds of $838.5 million and $101.9 million for proved and unproved properties, respectively.

Production Estimates

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2020 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	6,156	—	686	2,482	1,039	10,200	11,198
Southwest Saskatchewan(2)	10,740	4,812	21,251	467	14,991	1,643	40,042
Southeast Saskatchewan	14,395	—	34,821	11,941	28,869	4,408	66,703
Total CANADA(1)	31,291	4,812	56,758	14,890	44,900	16,252	117,943
U.S.							
North Dakota and Montana	—	—	12,726	3,213	9,967	—	17,601
Total U.S.(1)	—	—	12,726	3,213	9,967	—	17,601
Total Corporate(1)	31,291	4,812	69,484	18,104	54,867	16,252	135,544

Notes:
(1) Numbers may not add due to rounding.
(2) Assets in Southwest Saskatchewan include all southwest Saskatchewan, as well as Viking assets in western Saskatchewan.

In 2020, production at Viewfield in southeast Saskatchewan is estimated at 45,200 boe per day, representing 33%, and production in the Shaunavon area of southwest Saskatchewan is estimated at 28,000 boe per day, representing 21%, 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 2020.

The following table discloses, for each product type, the gross volume of production estimated by GLJ and Sproule for 2020 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	6,639	—	760	2,604	1,140	10,617	11,963
Southwest Saskatchewan(2)	12,189	5,037	25,181	538	17,385	1,805	46,143
Southeast Saskatchewan	15,644	—	39,618	13,411	32,527	4,812	74,896
Total CANADA(1)	34,472	5,037	65,559	16,553	51,052	17,235	133,002
U.S.							
North Dakota and Montana	—	—	15,565	3,739	11,640	—	21,244
Total U.S.(1)	—	—	15,565	3,739	11,640	—	21,244
Total Corporate(1)	34,472	5,037	81,123	20,292	62,691	17,235	154,246

Notes:
(1) Numbers may not add due to rounding.
(2) Assets in Southwest Saskatchewan include all southwest Saskatchewan, as well as Viking assets in western Saskatchewan .

In 2020, production at Viewfield in southeast Saskatchewan is estimated at 50,000 boe per day, accounting for 32%, and production in the Shaunavon area of southwest Saskatchewan is estimated at 32,800 boe per day, representing 21%, of the Corporation's total Proved plus Probable production estimate, respectively. Remaining areas each account for a small portion of the Corporation's production estimates for 2020.

Production History

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2019, our share of average daily production volume (prior to deducting royalties), and the prices received, royalties, production costs and transportation costs incurred and netbacks on a per unit of volume basis for each product type.

Average Daily Production Volume(1)

	Three Months Ended				Year Ended
	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Light and Medium Crude Oil (bbls/d)	33,423	32,420	29,265	25,366	30,094
Heavy Crude Oil (bbls/d)	4,824	4,633	4,722	4,819	4,749
Tight Oil (bbls/d)	65,289	67,312	60,052	61,891	63,617
NGLs (bbls/d)	15,514	16,517	16,258	16,686	16,248
Shale Gas (Mcf/d)	48,831	53,348	50,421	41,814	48,589
Conventional Natural Gas (Mcf/d)	21,254	20,817	19,443	17,901	19,843
Total (boe/d)	130,731	133,243	121,941	118,715	126,113
U.S.					
Light and Medium Crude Oil (bbls/d)	—	—	—	—	—
Heavy Crude Oil (bbls/d)	—	—	—	—	—
Tight Oil (bbls/d)	36,375	30,586	24,972	19,318	27,759
NGLs (bbls/d)	4,583	4,324	4,369	4,720	4,498
Shale Gas (Mcf/d)	25,594	25,936	26,558	14,632	23,160
Conventional Natural Gas (Mcf/d)	—	—	—	—	—
Total (boe/d)	45,224	39,233	33,767	26,477	36,117
TOTAL					
Light and Medium Crude Oil (bbls/d)	33,423	32,420	29,265	25,366	30,094
Heavy Crude Oil (bbls/d)	4,824	4,633	4,722	4,819	4,749
Tight Oil (bbls/d)	101,664	97,898	85,024	81,209	91,376
NGLs (bbls/d)	20,097	20,841	20,627	21,406	20,746
Shale Gas (Mcf/d)	74,425	79,284	76,979	56,446	71,749
Conventional Natural Gas (Mcf/d)	21,254	20,817	19,443	17,901	19,843
Total (boe/d)	175,955	172,476	155,708	145,192	162,230

Note:
(1) Numbers may not add due to rounding.

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Prices Received – net of hedging	63.10	71.13	67.56	68.29	67.46
Royalties	(7.74)	(10.84)	(10.38)	(9.84)	(9.66)
Production Costs(1)	(14.04)	(14.96)	(14.98)	(14.20)	(14.55)
Transportation Costs(1)	(2.44)	(2.54)	(2.51)	(2.69)	(2.54)
Netback	38.88	42.79	39.69	41.56	40.71
U.S.					
Prices Received – net of hedging	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs(1)	—	—	—	—	—
Transportation Costs(1)	—	—	—	—	—
Netback	—	—	—	—	—
TOTAL					
Prices Received – net of hedging	63.10	71.13	67.56	68.29	67.46
Royalties	(7.74)	(10.84)	(10.38)	(9.84)	(9.66)
Production Costs(1)	(14.04)	(14.96)	(14.98)	(14.20)	(14.55)
Transportation Costs(1)	(2.44)	(2.54)	(2.51)	(2.69)	(2.54)
Netback	38.88	42.79	39.69	41.56	40.71

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, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Prices Received	59.41	66.54	60.90	57.19	60.95
Royalties	(12.07)	(17.89)	(15.47)	(14.61)	(14.98)
Production Costs(1)	(13.42)	(13.73)	(13.90)	(12.39)	(13.35)
Transportation Costs(1)	(2.00)	(1.94)	(1.75)	(1.90)	(1.90)
Netback	31.92	32.98	29.78	28.29	30.72
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs(1)	—	—	—	—	—
Transportation Costs(1)	—	—	—	—	—
Netback	—	—	—	—	—
TOTAL					
Prices Received	59.41	66.54	60.90	57.19	60.95
Royalties	(12.07)	(17.89)	(15.47)	(14.61)	(14.98)
Production Costs(1)	(13.42)	(13.73)	(13.90)	(12.39)	(13.35)
Transportation Costs(1)	(2.00)	(1.94)	(1.75)	(1.90)	(1.90)
Netback	31.92	32.98	29.78	28.29	30.72

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, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Prices Received – net of hedging	68.14	71.69	69.40	68.59	69.48
Royalties	(6.74)	(7.62)	(6.70)	(6.63)	(6.94)
Production Costs(1)	(15.16)	(15.08)	(15.39)	(14.26)	(14.97)
Transportation Costs(1)	(3.45)	(3.09)	(2.87)	(3.06)	(3.12)
Netback	42.79	45.90	44.44	44.64	44.45
U.S.					
Prices Received – net of hedging	63.27	70.23	65.07	65.17	65.92
Royalties	(13.83)	(18.18)	(18.03)	(19.01)	(16.88)
Production Costs(1)	(14.01)	(13.59)	(15.27)	(9.79)	(13.44)
Transportation Costs(1)	(0.24)	(0.20)	(1.21)	(0.64)	(0.52)
Netback	35.19	38.26	30.56	35.73	35.08
TOTAL					
Prices Received – net of hedging	66.39	71.23	68.13	67.78	68.40
Royalties	(9.28)	(10.92)	(10.03)	(9.58)	(9.96)
Production Costs(1)	(14.75)	(14.61)	(15.35)	(13.20)	(14.51)
Transportation Costs(1)	(2.30)	(2.19)	(2.39)	(2.48)	(2.33)
Netback	40.06	43.51	40.36	42.52	41.60

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, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Prices Received	25.10	21.16	13.53	19.36	19.69
Royalties	(1.68)	(1.28)	(0.92)	(1.13)	(1.24)
Production Costs(1)	(6.33)	(4.93)	(3.22)	(4.43)	(4.70)
Transportation Costs(1)	(0.71)	(0.52)	(0.92)	(0.72)	(0.72)
Netback	16.38	14.43	8.47	13.08	13.03
U.S.					
Prices Received	27.22	22.25	16.19	17.81	20.85
Royalties	(5.64)	(4.67)	(4.02)	(4.18)	(4.63)
Production Costs(1)	(5.48)	(3.94)	(3.63)	(2.56)	(3.89)
Transportation Costs(1)	(0.21)	(0.35)	(0.19)	(0.08)	(0.20)
Netback	15.89	13.29	8.35	10.99	12.13
TOTAL					
Prices Received	25.58	21.39	14.09	19.02	19.94
Royalties	(2.58)	(1.98)	(1.57)	(1.80)	(1.98)
Production Costs(1)	(6.13)	(4.72)	(3.31)	(4.02)	(4.52)
Transportation Costs(1)	(0.60)	(0.48)	(0.77)	(0.58)	(0.61)
Netback	16.27	14.21	8.44	12.62	12.83

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, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Prices Received - net of hedging	4.04	2.17	2.26	3.88	3.03
Royalties	(0.31)	(0.16)	(0.10)	(0.26)	(0.20)
Production Costs(1)	(0.96)	(1.07)	(0.52)	(0.90)	(0.86)
Transportation Costs(1)	(0.20)	(0.19)	(0.19)	(0.31)	(0.22)
Netback	2.57	0.75	1.45	2.41	1.75
U.S.					
Prices Received - net of hedging	4.50	3.20	2.56	2.75	3.30
Royalties	(0.34)	(0.12)	(0.63)	0.72	(0.20)
Production Costs(1)	(1.03)	(0.63)	(0.62)	(0.46)	(0.71)
Transportation Costs(1)	(0.68)	(0.83)	(0.30)	(0.03)	(0.51)
Netback	2.45	1.62	1.01	2.98	1.88
TOTAL					
Prices Received - net of hedging	4.20	2.51	2.36	3.59	3.11
Royalties	(0.33)	(0.15)	(0.28)	—	(0.20)
Production Costs(1)	(0.98)	(0.92)	(0.55)	(0.78)	(0.81)
Transportation Costs(1)	(0.36)	(0.40)	(0.23)	(0.24)	(0.31)
Netback	2.53	1.04	1.30	2.57	1.79

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 – Conventional Natural Gas

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2019	June 30, 2019	Sept. 30, 2019	Dec. 31, 2019	2019
CANADA					
Prices Received - net of hedging	3.44	2.08	1.91	3.00	2.61
Royalties(2)	0.53	0.43	(0.35)	0.29	0.23
Production Costs(1)	(0.81)	(1.02)	(0.44)	(0.69)	(0.75)
Transportation Costs(1)	(0.30)	(0.30)	(0.33)	(0.18)	(0.28)
Netback	2.86	1.19	0.79	2.42	1.81
U.S.					
Prices Received - net of hedging	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs(1)	—	—	—	—	—
Transportation Costs(1)	—	—	—	—	—
Netback	—	—	—	—	—
TOTAL					
Prices Received - net of hedging	3.44	2.08	1.91	3.00	2.61
Royalties(2)	0.53	0.43	(0.35)	0.29	0.23
Production Costs(1)	(0.81)	(1.02)	(0.44)	(0.69)	(0.75)
Transportation Costs(1)	(0.30)	(0.30)	(0.33)	(0.18)	(0.28)
Netback	2.86	1.19	0.79	2.42	1.81

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, 2019 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	4,600	—	10,231	2,967	8,792	3,284	19,811
Flat Lake	4,825	—	27,474	10,381	23,230	1,581	46,815
Shaunavon	3,202	—	20,070	458	15,399	544	26,387
Other Canada (2)	17,467	4,749	5,842	2,442	1,168	14,434	33,100
Total CANADA(1)	30,094	4,749	63,617	16,248	48,589	19,843	126,113
U.S.							
North Dakota	—	—	14,531	3,635	10,187	—	19,864
Utah (3)	—	—	13,224	863	12,918	—	16,240
Other U.S.	—	—	4	—	55	—	13
Total U.S.(1)	—	—	27,759	4,498	23,160	—	36,117
Total(1)	30,094	4,749	91,376	20,746	71,749	19,843	162,230

Notes:
(1) Numbers may not add due to rounding.
(2) Includes all remaining assets in Canada.
(3) Utah assets were disposed of on October 18, 2019.

ADDITIONAL INFORMATION RESPECTING CRESCENT POINT

Directors and Officers

Crescent Point has a board of directors currently consisting of nine individuals. The directors are elected by the Corporation, at the direction of Shareholders by ordinary resolution, 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
Brad Borggard Calgary, Alberta	Senior Vice President, Corporate Planning and Capital Markets	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
Barbara Munroe (6) Calgary, Alberta	Director and Chair of the Board	2016
Laura A. Cillis (1) (2) Calgary, Alberta	Director	2014
James E. Craddock(1) (3) (5) Calgary, Alberta	Director	2019
John P. Dielwart (3) (4) Calgary, Alberta	Director	2019
Ted Goldthorpe (1) (5) New York, New York	Director	2017
Mike Jackson (1) (2) (5) Calgary, Alberta	Director	2016
Jennifer F. Koury (2) (4) Calgary, Alberta	Director	2019
Francois Langlois (3) (4) (5) Calgary, Alberta	Director	2018

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, Health and Safety Committee.
(5) Member of Corporate Governance and Nominating Committee.
(6) Chair of the Board shall serve in an ex officio capacity on each Committee.

As at February 13, 2020, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 801,703 Common Shares, representing approximately 0.2% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 0.5% 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 company in 2006, directly overseeing the development and operations of each of Crescent Point's core assets.

Mr. Bryksa has spent 18 years 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 Talisman Energy Inc., in addition to Crescent Point.

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

Brad Borggard, Senior Vice President, Corporate Planning and Capital Markets

Brad Borggard is the Senior Vice President, Corporate Planning and Capital Markets, a role he has held since 2018. Since joining the Corporation in January 2010, he has held other senior management positions including Vice President, Corporate Planning and Investor Relations, as well as Vice President, Corporate Planning. Prior to joining Crescent Point, Mr. Borggard was Managing Director, Institutional Equity Research at CIBC World Markets from 2004 until 2009. During that time, he was ranked as the top Canadian Royalty Trust analyst four times and the top Canadian E&P analyst twice.

Mr. Borggard has worked in other oil and gas related roles, with companies such as Scotia Capital Inc. and Gulf Canada Resources Ltd. He holds a Bachelor of Commerce degree (with honours) in Finance from the University of Calgary, as well as a Chartered Financial Analyst designation.

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 Tetrault 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 honours) 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 as Chief Operating Officer and Fairways E&P 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.

Barbara Munroe, Chair of the Board

Ms. Barbara Munroe has worked as a lawyer since being admitted to the Law Society of Alberta in 1991 and brings 27 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 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.

Laura A. Cillis, Director

Ms. Laura A. Cillis has 25 years of experience working in publicly traded, primarily international, organizations and has a broad range of leadership, corporate governance and financial experience. Ms. Cillis is currently a Director and member of the Audit and the Nominating & Corporate Governance committees at Western Forest Products Inc. In December 2019, she joined the board of Shawcor Ltd. and is a member of its Audit Committee.

Ms. Cillis was previously a member of and held a variety of roles on the Board of Directors for Solium Capital Inc., Enbridge Income Fund Holdings Inc. and the Enbridge Income Fund group of companies. She previously served as Senior Vice President, Finance and Chief Financial Officer for Calfrac Well Services Ltd. from November 2008 to June 2013. Prior thereto, she was the Chief Financial Officer of Canadian Energy Services L.P. since January 2006.

Ms. Cillis is a Chartered Professional Accountant, holds the ICD.D designation granted by the Institute of Corporate Directors and is a member of Financial Executives International. Ms. Cillis earned her Bachelor of Commerce degree from the University of Alberta.

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 has served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. in 2015 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. He is currently a member of Noble's Compensation and Corporate Governance and Nominating committees and is Chair of the Safety, Sustainability and Corporate Responsibility Committee. 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.

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 and is currently serving as a director on its Board of Directors. He is also Vice-Chairman and a Director of 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. 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 degree 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 the Canadian Association of Petroleum Producers, including 18 months as Chair.

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 a Director for the Calgary Zoo and is Chair of the first public/private partnership for the United Nations Women Global Innovation Coalition for Change. She holds a Bachelor of Commerce degree from the University of Alberta and the ICD.D Directors designation granted by the Institute of Corporate Directors.

Francois Langlois, Director

Mr. Langlois is an oil and gas executive who brings more than 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).

Ted Goldthorpe, Director

Mr. Ted Goldthorpe is a financial professional who has been 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 after joining the firm in 1999. Mr. Goldthorpe joined the Crescent Point Board in May 2017.

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 the Chairman of the Young Fellowship of The Duke of Edinburgh's Award, 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 Head 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.

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 company 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.

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. Shareholders that were enrolled in the DRIP and, previously, the premium component of the DRIP when the plan and component were, respectively, suspended will remain enrolled if the DRIP is reinstated and will automatically resume participation, including in the premium component if, and when, the DRIP and such component are reinstated.

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. Shareholders that were enrolled in the SDP when the plan was suspended will automatically resume participation if the SDP is reinstated.

Restricted Share Bonus Plan

Under the terms of the Corporation's Restricted Share Bonus Plan, any director, officer, consultant 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, 2019 the Corporation is authorized to issue up to 10,935,120 Common Shares, of which the Corporation had 3,636,194 Restricted Shares outstanding at December 31, 2019.

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: (1) 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; (2) to provide participants in the PSU Plan with compensation reflective of their responsibility, commitment and risk accompanying their role over the long-term; and (3) 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 2,920,444 PSUs outstanding at December 31, 2019.

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.

Pursuant to the terms of the Stock Option Plan, a maximum of 13,000,000 Common Shares may be issuable upon the exercise of outstanding stock options ("**Options**") granted under the Stock Option Plan (subject to adjustment for any subdivision or consolidation of the Common Shares). As at December 31, 2019, there were 2,833,342 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 administers 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 determines 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.

Long-Term Debt

At December 31, 2019, the Corporation had a $2.9 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 fourteen banks and has a maturity date of October 25, 2023. The current maturity date of the Bi-Lateral Credit Facility is October 25, 2023. The Syndicated Credit Facility's interest rate is based on either Canadian prime rate, U.S. base rate, London Interbank Offer 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 material restricted subsidiaries currently being CPEUS, CPUSH, CPHI and the Partnership. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances, London Interbank Offer 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 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, 2019, the Corporation had approximately $817.2 million drawn under its credit facilities.

At December 31, 2019, the Corporation had approximately $2.1 billion of senior guaranteed notes outstanding of which $201 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$1.38 billion senior guaranteed notes, the Corporation entered into cross currency swaps to hedge its foreign exchange exposure, fixing a notional amount of $1.52 billion for the purpose of interest and principal repayments. Concurrent with the issuance of US$30.0 million senior guaranteed notes, the Corporation entered a foreign exchange swap which fixed the principal repayment at a notional amount of $32.2 million.

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.

New Canadian Energy Regulator

In Canada, on August 28, 2019 the *Canadian Energy Regulator Act* replaced the *National Energy Board Act* and the National Energy Board became the Canada Energy Regulator (the "**CER**"). The CER now has jurisdiction over Canadian inter-provincial and international transportation of oil and gas. While the regulations created under the *National Energy Board Act* remain in force, the CER is updating existing regulations and creating new regulations through a phased approach. It is not yet known what effects the creation of the CER, and the changing regulatory landscape, will have on the Canadian oil and gas industry. The change in regulator from the NEB to the CER is not expected to have any particular effect on Crescent Point beyond the general effects on the industry.

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.

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 plus 1.23% should be the index level for the five-year period beginning July 1, 2016. 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.

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 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 licence from the CER and the issue of such a licence requires the approval of the Governor in Council.

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 licence. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Beginning January 2019, in an effort to reduce a surplus of oil in storage in Alberta, the AER began curtailing oil production (the " **Curtailment**"). While production limits have been incrementally increased since the Curtailment began, in August 2019, it was announced that Curtailment would be extended by a year and would remain in effect until December 31, 2020, with the possibility for earlier termination. Curtailment is set at the operator level, which as of October 1, 2019 leaves the first 20,000 barrels per day from a given operator exempt from the Curtailment. New conventional oil wells drilled after November 8, 2019 are also exempt from production limits. As the Corporation's assets in Alberta have historically produced and continue to produce less than the threshold amount required to be subject to the Curtailment, the Corporation's production has not been physically curtailed. Therefore, while Curtailment may be having a positive effect on the price of oil produced in Western Canada, and given that a significant portion of the Corporation's production is located outside of Alberta, but is sold at a price linked to Alberta oil prices, the Corporation may be experiencing a positive effect on pricing for its production without having to physically curtail its production in Alberta.

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 sales inter-state or internationally 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. However, the distinction between the FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of on-going litigation and, therefore, is subject to change. 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 licences imposed by the DOE. Natural gas may not be imported into Canada or exported from Canada without a licence or order from the CER or imported into the United States or exported from the United States without a licence from the DOE. Licences 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, may be obtained for a period that does not exceed 40 years in the case of export and 25 years in the case of import. In Canada, the approval of the Governor in Council is required prior to the issuance of a licence by the CER to import or export natural gas. Alternatively, natural gas may be imported into Canada or exported from Canada pursuant to an order from the CER. Orders may be obtained for a period of 2 years or less or for a period greater than 2 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. 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 North American Free Trade Agreement and the Canada-United States-Mexico Agreement

On January 1, 1994, the North American Free Trade Agreement (" **NAFTA**") among the governments of Canada, the U.S. and Mexico became effective. NAFTA carried forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, 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. All three countries were prohibited from imposing minimum export or import price requirements except in exceptional circumstances.

NAFTA also required the parties thereto to ensure that their respective energy regulators implement any energy regulatory measures in an orderly and equitable manner and in a manner which avoids disrupting contractual relationships to the maximum extent possible.

On November 30, 2018, the governments of Canada, the U.S. and Mexico signed the Canada-United States-Mexico Agreement (" **CUSMA**"), which is intended to supersede NAFTA once it has been ratified by the legislatures in all three countries. Mexico ratified CUSMA on June 9, 2019. The U.S. House of Representatives voted to ratify CUSMA on December 19, 2019, and the U.S. Senate ratified CUSMA on January 16, 2020. Canada has yet to ratify CUSMA. If CUSMA is ratified it will likely take effect in 2020. The full effect of CUSMA on the energy industry in Canada is not yet understood, though certain changes from NAFTA to CUSMA may have a positive effect on the energy industry, including the elimination of tariffs on diluent used to transport heavy oil from Canada into the United States.

In particular, the elimination of NAFTA Article 605 (Energy Proportionality), which forbid NAFTA members from restricting access to energy and basic petrochemical products should other international market access options emerge, is a significant change under the new agreement. This is likely due to the fact that the U.S. is now nearly self-sufficient in terms of oil production and is actively pursuing other markets themselves since the lifting of the U.S. oil export ban in December 2015.

Although the new trade agreement has not yet been fully ratified by Canada, Crescent Point does not anticipate any material change to its operations or marketing activities if the new agreement is ratified.

Royalties and Incentives

In addition to federal regulation, each province (and in the case of the U.S., each state) has legislation which governs 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 January 1, 2017. 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 is 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 0% to a cap of 40%.

The Old Framework also includes a natural gas royalty formula which 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 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, such as the Deep Oil Exploratory Well Program, the Enhanced Oil Recovery Royalty Program (the " **EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the " **IETP**"), were created pursuant to the Old Framework.

The Deep Oil Exploratory Well Regulation provides a limited royalty exemption for qualifying exploratory oil wells spudded or deepened between January 1, 2009 and December 31, 2013 that are deeper than 2,000 metres and have a producing interval below 2,000 metres.

Under the EOR Program, the Enhanced Oil Recovery Royalty Regulation, 2014 provides that 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.

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened after May 1, 2010 and on or before December 31, 2016, with producing intervals that are deeper than 2,000 metres.

The IETP was intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provided royalty reductions to successful applicants. Alberta Energy determined which projects qualify for the IETP, as well as the level of support that will be provided. The IETP expired on October 31, 2019.

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 per cent 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 per cent until their combined revenue equals their combined program specific cost allowances established under the ERP, which will 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 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**"), formerly the Saskatchewan Ministry of Economy (" **SME**").

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 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 one-fifth of the mineral rights in the Province of Saskatchewan are freehold mineral rights not owned by the 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 SME 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 16,000m^3, 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 m^3. 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 m^3, 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 m^3.

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.

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 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 1/6 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.

In response to North Dakota natural gas production reaching record highs and flaring levels exceeding the state's limit of 12%, the North Dakota Industrial Commission (the "**NDIC**") announced an initiative 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. 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.

On April 24, 2019, Governor Bergum signed into law HB 1439, under which incremental oil produced by injecting coal-generated carbon dioxide will be exempt from oil extraction taxes. Specifically, incremental oil produced from the Bakken or Three Forks formations will be exempt for a period of 10 years, and incremental oil produced from other formations will be exempt for a period of 20 years.

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 surface water bodies.

Canada

Environmental legislation in the Province of Alberta 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 *Emissions Management and Climate Resilience Act* 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. 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* and the *Oil and Gas Conservation Act*, which regulate harmful or potentially harmful activities and substances, 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*. 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 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 licences 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 and the AER Licensee Liability Management Program in Alberta and published by SMER in Directive PNG025 Licensee Liability Rating (LLR) Program in 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.

President Trump has indicated an intent to ease regulatory burdens on industry and on the oil and gas sector, including environmental regulations. However, any executive orders the President may issue, regulations the administration may promulgate, or any new legislation Congress may pass with the goal of reducing environmental statutory or regulatory requirements may be challenged in court. In addition, various state laws and regulations (and permits issued thereunder) will be unaffected by federal changes unless and until the state laws and corresponding permits are similarly changed, and any judicial review is completed.

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* (the "**CERCLA**") and comparable state statutes impose strict, joint and several 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 to file claims requiring cleanup actions, demands for reimbursement for cleanup costs, or natural resource damages, or for neighbouring landowners and other third parties to file claims for personal 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.

The *Federal Solid Waste Disposal Act* (the "**SWDA**"), the *Resource Conservation and Recovery Act* (the "**RCRA**") and comparable state statutes govern the 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. In May 2016, several environmental groups sued the Environmental Protection Agency (the " **EPA**") for failing to update its rules for management of oil and gas drilling waste under the RCRA. The petitioners requested that the EPA revise its regulations for waste materials generated as a result of oil and gas exploration and production activities. The petitioners claimed that the EPA has not reviewed or revised its regulations for management of wastes from oil and gas exploration and production operations since 1988, even though the statute requires the EPA to review and, if necessary, revise the regulations every three years. In December 2016, the court entered a Consent Decree resolving the litigation. Under the Consent Decree, the EPA agreed to propose no later than March 15, 2019 a rulemaking for revision of the regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. On April 23, 2019, the EPA issued a report detailing its finding that regulatory revisions were not necessary, satisfying the obligation under the Consent Decree. Despite this outcome there remains a risk that changes in the current RCRA exemption and comparable state laws could result in an increase in the costs to manage and dispose of wastes. Additionally, these exploration and production wastes may be regulated by state agencies as solid waste. Also, ordinary industrial wastes 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 oil and gas exploration and production 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 its 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, will change the scope of the rule's application. In August 2019, the Trump administration issued three final rules regarding implementation of the ESA. Under the new rules, the administration has changed the considerations for listing, delisting or reclassifying species. The new rules limits 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 new 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 remove the phrase "without reference to possible economic or other impacts of such determination" of a species' status, which may 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, now making it a case-by-case determination. These new rules apply only towards future listing of species, but they will significantly limit the scope of the ESA and likely result in less regulatory burdens on certain unoccupied spaces. The rules are currently being challenged by environmentalists and states in court. 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* (the "**NEPA**") requires a thorough review of the environmental impacts of "major federal actions" and a determination of whether proposed actions on federal and certain Indian 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 January 10, 2020, the White House Council on Environmental Quality (" **CEQ**") published a Notice of Proposed Rulemaking to revise NEPA's implementing regulations. The proposed changes to NEPA introduce a "non-major" category which will exempt certain types of governments, allowing them to move forward without an environmental assessment. The changes also propose to eliminate reference to "cumulative" effects and focus more on causation. This should 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. CEQ's proposed changes will make the NEPA process more efficient and timely by streamlining the entire process and proposing page and time limits. Additionally, the proposed rules introduce additional responsibilities for commenters. For example, comments will 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. If the proposed rules are adopted, it may result in a quicker turnaround time for obtaining leases and permits.

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. 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 January 23, 2020, the EPA and U.S. Army Corps of Engineers released a final rule to define WOTUS (the " **Final WOTUS Rule**"). The Final WOTUS Rule identifies four categories as jurisdictional WOTUS: 1) 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; 2) 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; 3) Ditches, which are artificial channels used to convey water that are either TNWs, constructed in a tributary, or constructed in an adjacent wetland; 4) 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; 5) Impoundments of other jurisdictional WOTUS; and 6) 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.

The Final WOTUS Rule also includes twelve exclusions. Notable is that isolated wetlands and ephemeral streams, which flow from heavy rainfall are excluded, as well as water-filled depressions created in upland incidental to mining, construction or gravel pits and stormwater control features. The new definition of WOTUS narrows the jurisdictional waters and may lessen regulatory oversight for projects in certain areas.

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. On January 11, 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. The 2017 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 *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, have been introduced in Congress. In addition, the EPA at the request of Congress recently 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, 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.

On May 16, 2013, the U.S. Bureau of Land Management (the " **BLM**") published revised proposed rules to regulate hydraulic fracturing on federal public lands and Indian lands. The proposed rules would address well stimulation operations, including requiring agency approval for certain activities, and would require certain disclosures of well stimulation fluids and other information, as well as address issues relating to flowback water. In addition, some states and localities have adopted, and others are considering adopting, regulations or ordinances that could restrict hydraulic fracturing in certain circumstances, or that would impose higher taxes, fees or royalties on natural gas production. In July of 2013, the BLM extended the public comment period on the proposed rules to August of 2013. On May 20, 2015 the BLM published its finalized rules on hydraulic fracturing. Following passing of the finalized rules, several states and industry groups filed suit to prevent enforcement of the rules and on September 30, 2015, a United States federal court granted a motion for a preliminary injunction preventing enforcement of the BLM's new rules, and the injunction was granted. The Obama Administration appealed the injunction. However, in light of the Trump Administration's pending repeal of the rule, the Court of Appeals for the Tenth Circuit determined that the appeals had been mooted, dismissed the appeals relating to the case, and ordered that the injunction be vacated. On December 28, 2017, BLM published a final rule rescinding the 2015 rule.

On January 10, 2019, the *Fracking Disclosure and Safety Act* (the "**FDSA**") was introduced in the House of Representatives. The purpose of the FDSA is to direct the BLM to issue regulations governing the use of hydraulic fracturing under oil and gas leases for federal lands. The FDSA identifies loopholes in a number of statutes that it seeks to close through increased reporting requirements, potential identification and classification of drilling waters and other wastes which should be classified as hazardous waste, and removal of certain air pollution exemptions for certain oil and gas sources. The SDWA would redefine "underground injection" to include the underground injection of fluids or propping agents pursuant to hydraulic fracturing operations related to oil, gas, or geothermal production activities but excluding underground injection of natural gas for purposes of storage. Although this bill was referred to committee, and remains there, it signals a continued interest in increasing regulatory oversight of hydraulic fracturing operations.

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 the incurrence of other unexpected material costs or liabilities.

The *Clean Air Act*, as amended, restricts the emission of air pollutants from many sources, including oil and gas operations. The *Clean Air Act* 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. *Clean Air Act* 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 ("**2016 NSPS 0000a 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 require 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 NSPS 0000a 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.

On September 24, 2019, the EPA issued a proposed rule to remove sources in the crude oil and natural gas transmission and storage segment from the source category, rescind the NSPS applicable to those sources, and rescind the methane-specific requirements of the NSPS application to sources in the production and processing segments. In the alternative, the EPA proposes to rescind the methane requirements of the NSPS applicable to all oil and natural gas sources, without removing any sources from the source category. The EPA indicates that these amendments will remove regulatory duplication and save the oil and gas industry US$17 to US$19 million a year.

The Emergency Planning and Community Right-to-Know Act (" **EPCRA**") requires certain facilities to disseminate information on chemical inventories to employees, local emergency planning committees and emergency response departments. In October 2015, the EPA indicated its intent to commence a rulemaking to add natural gas processing facilities to the list of facilities that must report under EPCRA. A proposed rule to add natural gas processing facilities to the scope of the industrial sectors covered by the reporting requirements under the EPCRA was published by the EPA in January of 2016, and the EPA accepted comments on the proposed rule until May 6, 2017. The future of this proposed rule under the Trump Administration is uncertain.

We are subject to a number of federal and state laws and regulations, including the federal *Occupational Safety and Health Act* (the "**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.

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 foster 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) a trading system for large industry, known as the output-based pricing system; and (ii) a regulatory charge on fuel, commonly known as carbon tax. Each province was given the choice to either accept the federal backstop 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 $20 per tonne of GHG emissions in 2019 and will increase by $10 per tonne per year until it reaches $50 per tonne in 2022.

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 in 2018 must report their emissions to Environment and Climate Change Canada.

In Alberta, greenhouse gases ("**GHG**") emissions are regulated under the *Emissions Management and Climate Resilience Act* and the *Technology Innovation and Emissions Reduction* ("**TIER**") *Regulation*, which came into effect January 1, 2020. The TIER system is mandatory for large emitters (≥ 100,000 tonnes CO2e of GHGs); however, facilities can be voluntarily registered into the system via individual opted-in facilities or creating an aggregated facility (two or more smaller facilities grouped 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. Crescent Point has an aggregate facility registered in the TIER system.

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 ("**OBPS**") were developed to reduce emissions intensity associated with fuel combustion -15% by 2030. Under the OBPS program operators of any large facility (>25,000 tCO2e) must register. Additionally, a voluntary aggregated facility (two or more smaller facilities grouped together) can also register in the OBPS program. Operators 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 into the 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 OBPS program.

In British Columbia, GHG emissions are regulated under the *Greenhouse Gas Emission Reporting Regulation* enacted pursuant to the Greenhouse Gas Industrial Reporting and Control Act which imposes GHG emissions reporting requirements upon B.C. facilities emitting 10,000 tonnes or more of GHG emissions per year. Facilities that emit 25,000 tonnes or more of GHGs must have their emission reports verified by an accredited third party. Crescent Point does not operate any facilities that are regulated by the British Columbia GHG emissions regulations.

U.S. Greenhouse Gas Emissions 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 has begun adopting and implementing regulations that restrict GHG emissions under existing provisions of the *Federal Clean Air Act* (the "**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 "tailors" 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 with reporting beginning in 2012 for emissions occurring in 2011.

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 has issued new regulations that limit GHG emissions associated with our operations which will require us to incur costs to inventory and reduce GHG emissions associated with our operations and which could adversely affect demand for the oil and natural gas that we produce.

On November 4, 2019, the U.S. initiated the formal process to withdraw from the Paris Agreement. Withdrawal is expected to take effect in one year. 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. Following the initiation of the U.S. withdrawal from the Paris Agreement, state and local climate regulatory efforts are expected to increase. 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. The earliest date for the complete withdrawal of the United States from the Paris Agreement is November 4, 2020.

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 regulation imposes both facility and equipment level requirements. Facilities that produce 60,000 m^3 of hydrocarbon gas annually in any of the past five years and facilities using pneumatic devices or compressors are covered by the regulations, as well as certain hydraulic fracturing activities.

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 (VOCs) 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 m3 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 come 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.

Beginning in 2020, operators of upstream oil and gas facilities will be required to; 1) 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 m3 of hydrocarbon gas or greater annually; 2) complete annual measurements of emissions from natural gas compressor vents to ensure emissions are under the applicable limit; and 3) eliminate venting from well completions involving hydraulic fracturing.

Beginning in 2023, operators of upstream oil and gas facilities will be required to; 1) meet a venting limit of 15,000m3 of gas per year at facilities that produce and/or receive more than 60,000m3 of gas per year, and; 2) 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.

The federal regulations will not apply in provinces which the federal government deems to have equivalent methane reduction regulations. As of January 1, 2020, Alberta and Saskatchewan governments are working toward achieving equivalency but have not formally reached an equivalency agreement with the federal regulations. Currently operators of these provinces are subject to dual regulation under the provincial and federal frameworks.

In Alberta, new design specifications have been put in place by the Alberta Energy Regulator (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.

The Government of Canada's GHG regulations apply to some of Crescent Point's operations and as a result additional costs are being incurred to comply with carbon pricing, GHG emission reduction requirements and to perform necessary monitoring, measurement, verification and reporting of GHG emissions. Further, our operations in British Columbia, Alberta and Saskatchewan are subject to provincial GHG emissions controls or reduction requirements.

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, 2019, Crescent Point owned approximately 20, 927 gross (17,160 net) producing, non-producing, abandoned wells for which abandonment and/or reclamation costs are expected to be incurred. During the 2019 financial year, Crescent Point spent approximately $28.7 million on well abandonments and environmental reclamation activities. Crescent Point estimates that it will spend approximately $35.0 million on well abandonments and environmental reclamation activities in 2020 and has budgeted accordingly. Crescent Point has estimated the net

present value (discounted at approximately 1.75% per annum) of its total decommissioning liability (wells and facilities) to be approximately $1.14 billion as at December 31, 2019, based on estimated undiscounted cash flows of approximately $1.09 billion.

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 GLJ and Sproule. 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 the Curtailment; 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 payments of dividends to Shareholders.

Dividends on the Corporation's Common Shares 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 will be reduced. Hence, the timing and amount of capital expenditures 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. Therefore, dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are made.

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 during those periods in which funds are so retained.

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 and state, 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 dividends 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 payments of dividends 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 dividends 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.

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

An increase in operating 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.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by the Corporation and, therefore, may reduce dividends to our Shareholders. Electricity, chemicals, supplies and labour costs are a few of the operating costs that are susceptible to material fluctuation.

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 dividends 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, 2019, approximately 7% 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 dividends 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;
- blowouts or other accidents;
- the effects of and response to COVID-19 (Coronavirus);
- blockades and social unrest;
- accounting delays;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

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

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.

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 through a formal Risk Management and Counterparty Credit Policy and maintains third party trade credit insurance, 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 dividends that are paid 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.

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 materially and adversely affect our ability to achieve our planned growth and operating results.

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 dividends to Shareholders may be materially reduced.

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, dividends to Shareholders may be reduced.

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

The economic impact on us of claims of aboriginal title is unknown. Aboriginal people have claimed aboriginal 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. Current protests affecting transportation and other infrastructure in Canada, if continued, 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.

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 (Coronavirus) 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 payment of dividends to Shareholders.

Our operations and expertise are currently focused 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;
- the level of consumer product demand;
- the impacts of COVID-19 (Coronavirus) and response;
- weather conditions;
- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa, 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 of foreign imports;
- actions of governmental authorities, including the Curtailment;
- 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;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall 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 impossible 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 or meet our financial obligations.

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

There is a risk that the interest rates will increase given the current low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease in dividends 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 payments of dividends 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 unfavourable 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 dividends 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.

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, AEP, the British Columbia Oil and Gas Commission, British Columbia Ministry of Environment, the SMER, the Manitoba Ministry of Conservation, Environment and Climate Change Canada, Health Canada, Transport Canada and the Department of Fisheries and Oceans , the CER, and, in the

U.S., the EPA, the U.S. Bureau of Indian Affairs, and the BLM, Energy and Minerals. 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, licence 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.

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, 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 fund and, if required, out of cash flow and, therefore, will reduce the amounts available for payment of dividends 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 U.S. 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 the GGPPA could result in increased operating costs as we adjust to the new fuel charges potentially imposed by the GGPPA. Additionally, complying with methane reduction regulations applicable to our business could result in Crescent Point incurring additional operating costs to in order to achieve compliance.

In Saskatchewan, it is not currently possible to predict the specific changes or the impact that the MRGHGA will have on the business, operations and/or finances of Crescent Point. 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. As well, 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.

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, some 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. 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.

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 yield-oriented 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. 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.

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 Court of Queen's Bench and the Alberta Court of Appeal to hold that receivers and trustees can no longer avoid the AER legislated authority to: (i) impose abandonment orders against licensees, or (ii) 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 will first be used to satisfy outstanding abandonment 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 Supreme Court of Canada's decision, the provincial regulation of environmental liabilities and associated decommissioning liability in the oil and gas industry may face substantial changes in the near future. There remains some uncertainty as to what regulatory measures will be developed by the provinces, either on a province-by-province basis or in concert with the federal government to address the *Orphan Well Association v Grant Thornton Ltd.* decision. The impact of any such regulatory measures 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 new rules to address the safety risks of transporting crude oil by rail.

In Canada, amendments have been made to the *Transportation of Dangerous Goods Regulation* 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 favourable 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 dividends 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 maintain dividends 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.

Potential for environmental non-governmental organization legal challenges.

Given that the U.S. government has not addressed climate change concerns, including, for example, a protracted delay by President Trump's administration in determining its own carbon-cost estimate (i.e., the estimate of how much carbon pollution costs society via climate damages) after rejecting the $40 per ton of carbon dioxide equivalent estimate of the Obama administration, environmental non-governmental organizations additional opportunities to pursue further legal challenges to oil and gas drilling and pipeline projects.

Risks Relating to Ownership of our Common Shares

Our Board of Directors has discretion in the payment of dividends and may choose not to maintain dividends in certain circumstances.

Any future dividends will be reviewed by the Board of Directors and adjusted from time to time to reflect current business conditions. The ability of the Corporation to pay dividends and the actual amount of such dividends will be dependent upon, among other things, the financial performance of the Corporation and its subsidiaries, its debt covenants and obligations, its ability to refinance its debt obligations on similar terms and at similar interest rates, its working capital requirements, its future tax obligations and its future capital requirements. A reduction in the amount of cash distributed to Shareholders may negatively affect the market price of the Common Shares.

Availability of Future Debt and Equity Financing.

The success of Crescent Point's business in the future is dependent on its ability to obtain debt and equity financing to maintain its operations. Crescent Point continues to invest in property, plant and equipment to grow its operations. This investment requires adequate financing that Crescent Point obtains through both internal operating cash flows and external debt and equity financings. There can be no assurance additional financing will be available in the future when needed or on terms acceptable to Crescent Point. The inability to access financing to support future growth opportunities could limit Crescent Point's operations and have a material adverse impact on Crescent Point's liquidity position, including its ability to pay obligations as they come due.

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.

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 Rrobable 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.

Additional taxation applicable to non-residents.

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.

Foreign exchange risk for non-resident Shareholders.

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.

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, fluctuations in working capital, 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 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 paid per Common Share by the Corporation for the periods indicated.

			Dividend per Common Share ($)
January 2017	–	December 2018	0.03 per month
January 2019	–	December 2019	0.01 per quarter

Normal Course Issuer Bid

On January 25, 2019, Crescent Point commenced a normal course issuer bid (the " **NCIB**") to purchase, for cancellation, up to 38,424,678 Common Shares, representing 7% of the Corporation's public float as at January 14, 2019. The NCIB expired on January 24, 2020. The actual number of Common Shares purchased under the NCIB was 26,238,600. The objective of the NCIB is to return capital to Shareholders in a way that is accretive to both Shareholders and the Corporation. Purchases of Common Shares under the 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)
2019			
January	4.70	3.82	96,001
February	4.44	3.24	85,821
March	4.76	3.67	129,654
April	5.98	4.02	156,106
May	5.56	4.49	102,381
June	4.60	3.85	74,502
July	4.53	3.85	76,256
August	4.35	3.69	64,784
September	6.30	4.19	109,581
October	5.74	4.68	64,007
November	5.47	4.60	75,672
December	5.94	4.44	78,052
2020			
January	6.30	4.27	81,104
February	4.49	3.30	73,870

NYSE	High (US$)	Low (US$)	Volume (000's)
2019			
January	3.55	2.88	43,620
February	3.39	2.44	53,888
March	3.55	2.74	70,887
April	4.45	3.02	71,583
May	4.16	3.32	67,813
June	3.45	2.89	54,733
July	3.47	2.95	46,762
August	3.27	2.77	45,139
September	4.76	3.13	77,709
October	4.32	3.55	60,168
November	4.13	3.49	49,413
December	4.58	3.34	55,001
2020			
January	4.84	3.23	43,237
February	3.38	2.47	49,812

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: Laura A. Cillis (Chair), James E. Craddock, Ted Goldthorpe and Mike Jackson, each of whom is considered "independent" and "financially literate" within the meaning of Multilateral 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 chairmen, 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.

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 Terms of Reference are 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
Laura A. Cillis	Ms. Laura A. Cillis has 25 years of experience working in publicly traded, primarily international, organizations and has a broad range of leadership, corporate governance and financial experience. Ms. Cillis is currently a Director and member of the Audit Committee of Shawcor Ltd. and she is a Director of Western Forest Products Inc. and a member of both its Audit Committee and its Nominating & Corporate Governance Committee.
	Ms. Cillis was previously a member of and held a variety of roles on the Board of Directors for Solium Capital Inc., Enbridge Income Fund Holdings Inc. and the Enbridge Income Fund group of companies. She previously served as Senior Vice President, Finance and Chief Financial Officer for Calfrac Well Services Ltd. from November 2008 to June 2013. Prior thereto, she was the Chief Financial Officer of Canadian Energy Services L.P. since January 2006.
	Ms. Cillis is a Chartered Professional Accountant, holds the ICD.D designation granted by the Institute of Corporate Directors and is a member of Financial Executives International. Ms. Cillis earned her Bachelor of Commerce degree from the University of Alberta.
James E. Craddock	Mr. James E. Craddock is a seasoned upstream executive who possesses broad-based technical knowledge with over 30 years of experience. He has served on Noble Energy Inc.'s Board of Directors since its merger with Rosetta Resources Inc. in 2015 and served as the Chairman, Chief Executive Officer and President of Rosetta from 2013 to 2015. He is currently a member of Noble's Compensation and Corporate Governance and Nominating committees and is Chair of the Safety, Sustainability and Corporate Responsibility Committee. 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.
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.
	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 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.

External Auditor Services Fees

For services provided to the Corporation and its subsidiaries the years ended December 31, 2019 and 2018 PricewaterhouseCoopers LLP billed approximately $1,290,025 and $1,746,288, respectively, as detailed below:

	Year ended December 31	
	2019	2018
PricewaterhouseCoopers		
Audit fees	$ 1,151,551	$ 1,529,983
Audit-related fees	$ 25,382	$ 216,305
Tax fees	—	—
All other fees	$ 113,093	$ —
Total	$ 1,290,025	$ 1,746,288

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 4, 2020 in respect of the Corporation's consolidated financial statements as at December 31, 2019 and December 31, 2018 and the Corporation's internal control over financial reporting as at December 31, 2019. 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 U.S. Securities and Exchange Commission.

Reserve estimates contained in this AIF are derived from reserve reports prepared by GLJ and Sproule. As of the date hereof, GLJ, as a group and Sproule, as a group, do 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.shtml 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 June 14, 2019, which is available on SEDAR. Additional financial information is provided in our comparative consolidated financial statements and management's discussion and analysis for our most recently completed financial year ended December 31, 2019.

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

AUDIT COMMITTEE TERMS OF REFERENCE

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 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 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 and properly certified;

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

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

(iv) 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 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 and to review 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 from among the directors of the Corporation.

(b) All members of the committee (the "Members") must be "independent" under Multilateral Instrument 52-110. All Members must be "financially literate" (i.e., have the ability to read and understand a balance sheet, an income statement and a cash flow statement). In particular, at least one member shall have, through (i) education and experience as a principal financial officer, principal accounting officer, controller, public accountant or auditor or experience in one or more positions that involve the performance of similar functions; (ii) experience actively supervising a principal financial officer, principal accounting officer, controller, public accountant, auditor or person performing similar functions; (iii) experience overseeing or assessing the performance of companies or public accountants with respect to the preparation, auditing or evaluation of financial statements; or (iv) other relevant experience:

- An understanding of accounting principles and financial statements;
- The ability to assess the general application of such principles in connection with the accounting for estimates, accruals and reserves;
- Experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the Corporation’s financial statements, or experience actively supervising one or more persons engaged in such activities;
- An understanding of internal controls and procedures for financial reporting; and
- An understanding of audit committee functions.

(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 (the "Exchange Act"), and the rules, if any, adopted by the U.S. Securities and Exchange Commission ("SEC") 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 exofficio member of the Committee and shall be entitled to attend all meetings of the Committee.

(h) In the event of a vacancy arising in the Committee or a loss of independence of any Member, the Committee will fill the vacancy 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 him 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 Terms of Reference, 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 these Terms of Reference 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 Terms of Reference

These Terms of Reference outline 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 Chairmen, 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 these Terms of Reference. 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 Committee's Terms of Reference.

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 these Terms of Reference 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 facsimile, 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 his or her deputee) 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 and the internal audit and tax 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 policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

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

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

(e) 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 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, regarding accounting, internal accounting controls or auditing 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 or auditing matters;

(b) Copies of complaints received will be sent to the Members of the Committee;

(c) 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

(d) 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

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1. Reserves Committee 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.

2. 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
- 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.

3. Reserves 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.

4. 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.

5. 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 exofficio 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 his or her successor is appointed, unless he or she resigns or is removed by the Board or he or she 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 his or her position as a member of the Committee on the earliest of (i) the appointment of his or her 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.

6. 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.

7. Secretary

The Corporate Secretary of the Corporation 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.

8. 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:

(a) 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.

(b) 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.

(c) 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.

(d) Every question at a Committee meeting shall be decided by a majority of the votes cast.

(e) 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.

(f) 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.

(g) 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.

9. Notice of Meeting

Notice of the time and place of each meeting may be given orally, or by electronic means, or in writing, or by facsimile 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.

10. 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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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 plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, 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 (before income taxes, 10% discount rate - $M)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	December 31, 2019	Canada	—	2,015,860	—	**2,015,860**

6. In our opinion, the reserves data 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 reports.

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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 14, 2020

ORIGINALLY SIGNED BY

Todd J. Ikeda, P. Eng.
Vice President

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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 plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, 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 (before income taxes, 10% discount rate - Cdn. $M)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country or Foreign Geographic Area)**	**Audited**	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	December 31, 2019	U.S.A.	—	1,366,833	—	**1,366,833**

6. In our opinion, the reserves data 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 reports.

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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 14, 2020

ORIGINALLY SIGNED BY

Todd J. Ikeda, P. Eng
Vice President

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, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, 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 plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - Cdn. $M)			
Independent Qualified Reserves Evaluator or Auditor	**Effective Date of Evaluation Report**	**Location of Reserves (Country)**	**Audited (M$)**	**Evaluated (M$)**	**Reviewed (M$)**	**Total (M$)**
Sproule	December 31, 2019	Canada				
Total			Nil	8,404,263	Nil	8,404,263

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, entitled “Evaluation of Certain Saskatchewan P&NG Reserves of Crescent Point Energy Corp. (As of December 31, 2019)”.

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

Executed as to our report referred to above:

Sproule Associates Limited, Calgary, Alberta January 21, 2020

ORIGINALLY SIGNED BY

Douglas O. McNichol, P.Eng.
Senior Manager, Engineering

Vincent K. Hui, P.Eng.
Senior Petroleum Engineer

Shishir Shivhare, P.Eng.
Petroleum Engineer

Nora T. Stewart, P.Eng.
Senior Vice President, Responsible Member Engineering

Ian Kirkland, P.Geol.
Senior Geologist, Responsible Member Geoscience

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.

GLJ Petroleum Consultants and Sproule Associates Limited, each an independent qualified reserves evaluators have 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 evaluators;

(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the board of directors 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 4, 2020

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.

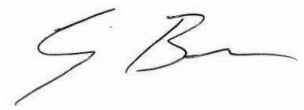
The Board of Directors, through its Audit Committee, has reviewed the consolidated financial statements including notes thereto with management and PricewaterhouseCoopers LLP. The members of the Audit Committee are composed of independent directors who are not employees of the Company. The Audit Committee 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, 2019. 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, 2019. 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, 2019, has audited the effectiveness of the Company's internal control over financial reporting as at December 31, 2019.



Craig Bryksa
President and Chief Executive Officer



Ken Lamont
Chief Financial Officer

March 4, 2020



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, 2019 and 2018, 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, 2019, 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, 2019 and 2018, and its financial performance and its cash flows for the years then ended in conformity with International Financial Reporting Standards ("IFRS") 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, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle
As discussed in Note 4 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019 due to the adoption of IFRS 16, Leases.

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 and deferred tax assets, net

As described in Notes 2, 3, 8 and 23 to the consolidated financial statements, the Company had a net balance of $7,787.6 million for development and production assets and deferred tax asset net balance of $745.3 million at December 31, 2019. Management also recorded a depletion expense of $1,087.4 million and impairment expense of $1,466.4 million for the year ended December 31, 2019. 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 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 infrastructures, the existence of common sales points, geography, geologic 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 includes 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. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Management determined the recoverable amounts 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. Deferred tax assets are recognized to the extent that temporary differences will be recoverable in future periods. The calculation of the deferred tax assets involves significant estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flows including proved plus probable oil and gas reserves estimates and the application of tax laws. Determining the Company's proved plus probable oil and gas reserves required the use of significant estimates and judgement by management related to production forecasts, commodity prices, costs and related future cash flows. 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 and deferred tax 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, determining the recoverable



amount for each CGU, and assessing the recognition of deferred tax assets. 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 used for the recoverable amounts of the CGUs as well as the recognition of deferred tax assets, and the after-tax discount rate used for the recoverable amount of the CGUs. 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, management's recognition of deferred tax assets and the calculation of DD&A expense. These procedures also included, among others, testing management's processes for determining the recoverable amount for each CGU, depletion expense for development and production assets and the recognizable amount of the deferred tax assets, which included evaluating the appropriateness of the methods used by management in making these estimates; testing the completeness, accuracy and relevance 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 and the recognition of the deferred tax assets. Professionals with specialized skill and knowledge were used to assist in evaluating the reasonableness of the recoverability analysis, including the discount rate used within the recoverability calculations 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 and objectivity were understood, as well as their methods and assumptions. The procedures performed also included tests of the data used by management's specialists and an evaluation of their 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 4, 2020

We have served as the Company's auditor since 2001.

CONSOLIDATED BALANCE SHEETS

As at December 31			
(Cdn$ millions)	Notes	**2019**	2018
ASSETS			
Cash		**56.9**	15.3
Accounts receivable		**295.9**	322.6
Prepaids and deposits		**6.9**	4.6
Derivative asset	26	**76.8**	244.1
Assets held for sale	9	**195.0**	—
Total current assets		**631.5**	586.6
Derivative asset	26	**251.1**	351.5
Other long-term assets	5	**22.4**	43.2
Exploration and evaluation	6, 7	**245.5**	472.6
Property, plant and equipment	7, 8	**7,841.6**	10,430.2
Right-of-use asset	13	**123.5**	—
Goodwill	10	**230.9**	244.0
Deferred income tax	23	**745.3**	602.3
Total assets		**10,091.8**	12,730.4
LIABILITIES			
Accounts payable and accrued liabilities		**479.4**	549.4
Current portion of long-term debt	12	**201.0**	99.8
Derivative liability	26	**18.4**	—
Other current liabilities	11	**68.6**	39.4
Liabilities associated with assets held for sale	9	**7.9**	—
Total current liabilities		**775.3**	688.6
Long-term debt	12	**2,704.1**	4,176.9
Other long-term liabilities	14	**10.8**	48.3
Lease liability	13	**149.9**	—
Decommissioning liability	15	**1,109.0**	1,203.8
Total liabilities		**4,749.1**	6,117.6
SHAREHOLDERS' EQUITY			
Shareholders' capital	16	**16,449.0**	16,546.9
Contributed surplus		**35.1**	41.4
Deficit	17	**(11,636.9)**	(10,567.2)
Accumulated other comprehensive income		**495.5**	591.7
Total shareholders' equity		**5,342.7**	6,612.8
Total liabilities and shareholders' equity		**10,091.8**	12,730.4

Commitments (Note 28)

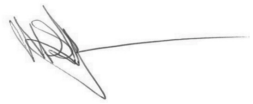
Subsequent Events (Note 32)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:



Laura A. Cillis
Director



Mike Jackson
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (Cdn$ millions, except per share amounts)	Notes	**2019**	2018 (Revised)
REVENUE AND OTHER INCOME			
Oil and gas sales	31	**3,336.0**	3,887.5
Purchased product sales		**23.9**	25.4
Royalties		**(482.8)**	(592.4)
Oil and gas revenue		**2,877.1**	3,320.5
Commodity derivative losses	19, 26	**(61.0)**	(56.4)
Other loss	20	**(159.9)**	(143.5)
		2,656.2	3,120.6
EXPENSES			
Operating		**727.6**	853.8
Purchased product		**25.4**	24.0
Transportation		**123.7**	131.7
General and administrative		**91.9**	121.9
Interest	21	**170.4**	163.7
Foreign exchange (gain) loss	22	**(61.1)**	18.7
Share-based compensation	24	**24.9**	46.0
Depletion, depreciation, amortization and impairment	6, 8, 13	**2,713.3**	5,284.7
Accretion and financing	13, 15	**32.4**	31.5
		3,848.5	6,676.0
Net income (loss) before tax		**(1,192.3)**	(3,555.4)
Tax expense (recovery)			
Current	23	**0.4**	0.3
Deferred	23	**(159.4)**	(938.8)
Net income (loss)		**(1,033.3)**	(2,616.9)
Other comprehensive income (loss)			
Items that may be subsequently reclassified to profit or loss			
Foreign currency translation of foreign operations		**(96.2)**	239.5
Comprehensive income (loss)		**(1,129.5)**	(2,377.4)
Net income (loss) per share	25		
Basic		**(1.89)**	(4.77)
Diluted		**(1.89)**	(4.77)

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, 2018		**16,546.9**	**41.4**	**(10,567.2)**	**591.7**	**6,612.8**
Adoption of accounting policy	4			**(14.4)**		**(14.4)**
Redemption of restricted shares	16	**24.7**	**(25.5)**			**(0.8)**
Common shares repurchased	16	**(122.6)**				**(122.6)**
Share-based compensation	24		**23.4**			**23.4**
Forfeit of restricted shares	24		**(4.2)**			**(4.2)**
Net income (loss)				**(1,033.3)**		**(1,033.3)**
Dividends ($0.04 per share)				**(22.0)**		**(22.0)**
Foreign currency translation adjustment					**(96.2)**	**(96.2)**
December 31, 2019		**16,449.0**	**35.1**	**(11,636.9)**	**495.5**	**5,342.7**
December 31, 2017		16,489.6	72.9	(7,751.8)	352.2	9,162.9
Redemption of restricted shares		57.3	(59.0)			(1.7)
Share-based compensation			35.1			35.1
Forfeit of restricted shares			(7.6)			(7.6)
Net income (loss)				(2,616.9)		(2,616.9)
Dividends ($0.36 per share)				(198.5)		(198.5)
Foreign currency translation adjustment					239.5	239.5
December 31, 2018		16,546.9	41.4	(10,567.2)	591.7	6,612.8

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31			
(Cdn$ millions)	Notes	**2019**	2018
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES			
Net income (loss)		**(1,033.3)**	(2,616.9)
Items not affecting cash			
Other loss	20	**189.0**	143.5
Deferred tax recovery	23	**(159.4)**	(938.8)
Share-based compensation	24	**14.9**	19.8
Depletion, depreciation, amortization and impairment	6, 8, 13	**2,713.3**	5,284.7
Accretion and financing	13, 15	**32.4**	31.5
Unrealized (gains) losses on derivatives	19, 21, 26	**269.6**	(439.4)
Translation of US dollar long-term debt	22	**(175.3)**	324.5
Other		**0.3**	(2.5)
Realized gain on cross currency swap maturity	22	**(32.4)**	(70.3)
Decommissioning expenditures		**(28.7)**	(25.3)
Change in non-cash working capital	30	**(47.5)**	37.2
		1,742.9	1,748.0
INVESTING ACTIVITIES			
Development capital and other expenditures	6, 8	**(1,306.2)**	(1,817.8)
Capital acquisitions	7	**(15.9)**	(15.4)
Capital dispositions	7	**917.1**	243.3
Other long-term assets	5	**18.8**	162.1
Change in non-cash working capital	30	**41.2**	(81.6)
		(345.0)	(1,509.4)
FINANCING ACTIVITIES			
Issue of shares, net of issue costs		**(0.8)**	(1.7)
Common shares repurchased	16	**(122.6)**	—
Decrease in bank debt, net	30	**(1,099.2)**	(360.0)
Issuance of senior guaranteed notes		**—**	267.3
Repayment of senior guaranteed notes	30	**(98.2)**	(65.0)
Realized gain on cross currency swap maturity	22	**32.4**	70.3
Payments on lease liability	13, 30	**(34.1)**	—
Cash dividends	30	**(22.0)**	(198.5)
Change in non-cash working capital	30	**(11.2)**	(0.3)
		(1,355.7)	(287.9)
Impact of foreign currency on cash balances		**(0.6)**	2.2
INCREASE (DECREASE) IN CASH		**41.6**	(47.1)
CASH AT BEGINNING OF YEAR		**15.3**	62.4
CASH AT END OF YEAR		**56.9**	15.3

See accompanying notes to the consolidated financial statements.

Supplementary Information:

Cash taxes paid	**(0.5)**	—
Cash interest paid	**(159.1)**	(177.1)

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 4, 2020.

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 4, 2020, 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$” 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. 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 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 geoscientific interpretation, 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 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, 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 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, the availability of cash flows including reserve estimates 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 of 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. Development and production assets are accumulated into CGUs and represent 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 replaced or 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 over the estimated useful lives of the related assets, ranging from5 to 16 years on a straight-line basis.

Impairment

The carrying amounts of PP&E, which includes 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 infrastructures, the existence of common sales points, geography, geologic 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 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 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. 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. 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.

Performance share units ("PSUs") are accounted for at fair value. 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, accrued dividends 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.

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.

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, 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 cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and 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 restated 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 restated to Canadian dollars at exchange rates in effect at the balance sheet date and income and expenses are restated 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, 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, 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.

Prior to January 1, 2019, leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term. Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases within property, plant and equipment.

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, 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) 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 recoveries 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

On January 1, 2019, the Company adopted IFRS 16*Leases* ("IFRS 16") using the modified retrospective approach. Under the modified retrospective approach comparative information has not been restated and continues to be reported under IAS 17 *Leases* and IFRIC 4 *Determining Whether an Arrangement Contains a Lease*. The Company has applied the following practical expedients permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets.

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a ROU asset if the underlying asset is of a lower dollar value; and
- Use of the Company's previous assessment of impairment under IAS 37*Provisions, Contingent Liabilities and Contingent Assets* for onerous contracts instead of re-assessing the ROU asset for impairment on January 1, 2019.

The lease liability is calculated as the present value of the remaining lease payments, discounted using the Company's borrowing rate on January 1, 2019. The Company records financing expense on the lease liability and depreciation expense on the ROU asset and the associated ROU asset is measured as follows on a lease-by-lease basis:

- The amount equal to the lease liability on January 1, 2019 with no impact on retained earnings; or
- The balance on January 1, 2019 as if IFRS 16 had always been applied on the commencement of the lease, using the Company's borrowing rate on January 1, 2019 and with an impact on retained earnings calculated as the difference between the lease liability and the ROU asset values.

The following table reconciles the amounts in the consolidated balance sheet as at December 31, 2018 to the opening balance sheet on transition:

($ millions)	As at December 31, 2018	Adjustments	Restated balance as at January 1, 2019
ROU asset	—	153.3	153.3
Deferred income tax	602.3	5.3	607.6
Other current liabilities [1] [2]	(39.4)	(26.4)	(65.8)
Other long-term liabilities [2]	(48.3)	44.8	(3.5)
Lease liability [1]	—	(191.4)	(191.4)
Deficit	10,567.2	14.4	10,581.6

(1) The weighted average incremental borrowing rate used to determine the lease liability on transition was 4.40%.

(2) On initial adoption, the Company elected to use the practical expedient to apply the previous assessment under IAS 37 for onerous contracts and deferred lease inducements. As a result, $11.0 million onerous contract provision and $39.8 million lease inducement were offset against the ROU asset.

The following table reconciles the commitments as at December 31, 2018 to the Company's lease liability as at January 1, 2019:

($ millions)	
Operating leases (building, vehicle, and equipment leases)	**348.6**
Transportation commitments	**90.0**
Total contractual commitments as at December 31, 2018	**438.6**
Less:	
Commitments that do not contain a lease	**(90.0)**
Non-lease components	**(122.9)**
Short-term leases	**(0.5)**
Add:	
Subleased office space recoveries	**44.8**
Impact of discounting	**(46.2)**
Lease liability as at January 1, 2019	**223.8**

New accounting standards and amendments not yet adopted

The Company has not adopted any new standards or amendments to standards that are effective beginning on or after January 1, 2020 as the Company's consolidated financial statements are not expected to be materially impacted.

5. OTHER LONG-TERM ASSETS

($ millions)	**2019**	2018
Long-term investments	**6.7**	8.7
Other receivables	**15.7**	15.8
Reclamation fund	**—**	18.7
Other long-term assets	**22.4**	43.2

a) Long-term investments

($ millions)	2019	2018
Investments in public companies, beginning of year	**8.7**	65.1
Acquired through capital dispositions	**—**	112.6
Dispositions	**—**	(152.8)
Unrealized loss recognized in other loss	**(2.0)**	(16.2)
Investments in public companies, end of year	**6.7**	8.7

Public companies

The Company holds common shares in publicly traded oil and gas companies. The investments are classified as financial assets at fair value through profit or loss and are fair valued at each period with the resulting gain or loss recorded in net income. At December 31, 2019, the investments were recorded at a fair value of $6.7 million which was $0.6 million more than the original cost of the investments. At December 31, 2018, the investments were recorded at a fair value of $8.7 million which was $2.6 million more than the original cost of the investments.

b) Other receivables

At December 31, 2019, the Company had investment tax credits of $15.7 million (December 31, 2018 - $15.8 million).

6. EXPLORATION AND EVALUATION ASSETS

($ millions)	2019	2018
Exploration and evaluation assets at cost	**1,848.1**	2,325.0
Accumulated amortization	**(1,602.6)**	(1,852.4)
Net carrying amount	**245.5**	472.6
Reconciliation of movements during the year		
Cost, beginning of year	**2,325.0**	2,305.1
Accumulated amortization, beginning of year	**(1,852.4)**	(1,670.2)
Net carrying amount, beginning of year	**472.6**	634.9
Net carrying amount, beginning of year	**472.6**	634.9
Acquisitions through business combinations, net	**7.3**	10.2
Additions	**384.9**	673.3
Dispositions	**(101.9)**	(7.5)
Transfers to property, plant and equipment	**(380.6)**	(705.9)
Amortization	**(129.1)**	(157.2)
Foreign exchange	**(7.7)**	24.8
Net carrying amount, end of year	**245.5**	472.6

Impairment test of exploration and evaluation assets

There were no indicators of impairment at December 31, 2019.

7. CAPITAL ACQUISITIONS AND DISPOSITIONS

In the year ended December 31, 2019, the Company incurred $6.3 million (year ended December 31, 2018 - $5.1 million) of transaction costs related to acquisitions through business combinations and dispositions that were recorded as general and administrative expenses.

a) Major Property Dispositions

Uinta Basin asset disposition

In the year ended December 31, 2019, the Company disposed its Uinta Basin assets for total consideration of $676.8 million. These assets were classified as held for sale at September 30, 2019 resulting in an impairment charge of $241.4 million recorded on PP&E as a component of DD&A and impairment expense. A further impairment charge of $8.7 million was recorded upon closing of the transaction in the fourth quarter of 2019.

Southeast Saskatchewan asset disposition

In the year ended December 31, 2019, the Company disposed of certain southeast Saskatchewan conventional assets for consideration of $196.9 million. These assets had a net carrying value of $390.7 million, resulting in a loss of $193.8 million.

b) Minor property acquisitions and dispositions

In the year ended December 31, 2019, the Company completed minor property acquisitions and dispositions for net consideration of $50.4 million. These assets had a net carrying value of $55.8 million, resulting in a loss of $5.4 million. During the year ended December 31,2019, the Company recorded $8.5 million of impairment related to assets held for sale at March 31, 2019. These assets have been disposed of as at December 31, 2019.

($ millions)	Uinta Basin	Southeast Saskatchewan	Other minor
Dispositions:			
Consideration			
Cash	653.9	196.9	50.4
Working capital	22.9	—	—
	676.8	196.9	50.4
Carrying Value			
Derivative asset	(16.2)	—	—
ROU asset	(3.1)	—	—
Exploration and evaluation	(90.7)	(3.2)	(0.7)
Property, plant and equipment	(670.2)	(466.4)	(85.6)
Goodwill	—	(13.1)	—
Lease liability	3.0	—	—
Decommissioning liability	100.4	92.0	30.5
	(676.8)	(390.7)	(55.8)
Loss on capital dispositions	—	(193.8)	(5.4)

8. PROPERTY, PLANT AND EQUIPMENT

($ millions)	**2019**	2018
Development and production assets	**23,038.6**	26,635.3
Corporate assets	**117.2**	114.6
Property, plant and equipment at cost	**23,155.8**	26,749.9
Accumulated depletion, depreciation and impairment	**(15,314.2)**	(16,319.7)
Net carrying amount	**7,841.6**	10,430.2
Reconciliation of movements during the year		
Development and production assets		
Cost, beginning of year	**26,635.3**	25,881.1
Accumulated depletion and impairment, beginning of year	**(16,262.2)**	(11,877.1)
Net carrying amount, beginning of year	**10,373.1**	14,004.0
Net carrying amount, beginning of year	**10,373.1**	14,004.0
Acquisitions through business combinations, net	**8.7**	12.2
Additions	**1,075.7**	1,083.6
Dispositions, net	**(1,230.9)**	(523.8)
Transfers from exploration and evaluation assets	**380.6**	705.9
Reclassified as assets held for sale	**(195.0)**	—
Depletion	**(1,087.4)**	(1,412.4)
Impairment	**(1,466.4)**	(3,704.8)
Foreign exchange	**(70.8)**	208.4
Net carrying amount, end of year	**7,787.6**	10,373.1
Cost, end of year	**23,038.6**	26,635.3
Accumulated depletion and impairment, end of year	**(15,251.0)**	(16,262.2)
Net carrying amount, end of year	**7,787.6**	10,373.1
Corporate assets		
Cost, beginning of year	**114.6**	106.4
Accumulated depreciation, beginning of year	**(57.5)**	(48.0)
Net carrying amount, beginning of year	**57.1**	58.4
Net carrying amount, beginning of year	**57.1**	58.4
Additions	**2.9**	7.7
Depreciation	**(5.9)**	(9.2)
Foreign exchange	**(0.1)**	0.2
Net carrying amount, end of year	**54.0**	57.1
Cost, end of year	**117.2**	114.6
Accumulated depreciation, end of year	**(63.2)**	(57.5)
Net carrying amount, end of year	**54.0**	57.1

At December 31, 2019, future development costs of $5.15 billion (December 31, 2018 - $7.23 billion) were included in costs subject to depletion.

Direct general and administrative costs capitalized by the Company during the year ended December 31, 2019 were $40.0 million (year ended December 31, 2018 - $48.0 million), including $4.3 million of share-based compensation costs (year ended December 31, 2018 - $7.7 million).

Impairment test of property, plant and equipment

2019 Impairment

For the year ended December 31, 2019, the decrease in forecast benchmark commodity prices in addition to losses recognized on dispositions during the year were indicators of impairment. As a result, impairment and recovery testing were required 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, 2019:

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030 [2]
WTI ($US/bbl) [1]	61.00	63.75	66.18	67.91	69.48	71.07	72.68	74.24	75.73	77.24	78.79
Exchange Rate ($US/$Cdn)	0.760	0.770	0.785	0.785	0.785	0.785	0.785	0.785	0.785	0.785	0.785
WTI ($Cdn/bbl)	80.26	82.79	84.31	86.51	88.51	90.54	92.59	94.57	96.47	98.39	100.37
AECO ($Cdn/MMbtu) [1]	2.04	2.32	2.62	2.71	2.81	2.89	2.96	3.03	3.09	3.16	3.24

(1) 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.

(2) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2030 to the end of the reserve life. Exchange rates are assumed to be constant at 0.785.

At December 31, 2019, the Company determined that the carrying amount of the Southeast Saskatchewan, Southwest Saskatchewan, Southern Alberta and Northern Alberta CGUs exceeded their recoverable amount. The full amount of the impairments were attributed to PP&E and, as a result, impairment losses of $1.21 billion were recorded as a component of DD&A and impairment expense. The impairment loss was largely due to the decrease in forecast benchmark commodity prices used in impairment testing at December 31, 2019 compared to December 31, 2018.

In future periods, the impairment can be reversed up to the original carrying value less any associated DD&A if the estimated recoverable amounts of the CGUs exceed their carrying amount. At December 31, 2019, the after tax impairment losses that can be reversed for the Canada and U.S. operating segments were $3.66 billion and $52.8 million, respectively.

The following table summarizes the impairment expense for the year ended December 31, 2019 by CGU:

CGU ($ millions, except %)	**Operating segment**	**Recoverable amount**	**Discount rate**	**Impairment**	**Impairment, net of tax**
Southeast Saskatchewan	Canada	4,087.0	15.00%	811.7	594.1
Southwest Saskatchewan	Canada	1,704.1	15.00%	333.5	244.1
Southern Alberta	Canada	858.0	15.00%	56.0	41.0
Northern Alberta	Canada	1.1	15.00%	6.6	4.8
Total impairment		6,650.2		1,207.8	884.0

Changes in any of the key judgments, such as a revision in reserves, changes in forecast benchmark commodity prices, foreign exchange rates, capital or operating costs would impact the recoverable amounts of assets and any recoveries or impairment charges would affect net income. The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price estimates at December 31, 2019, with all other variables held constant:

CGU	Discount Rate		Commodity Prices	
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%
Southeast Saskatchewan	(265.1)	291.8	489.8	(486.7)
Southwest Saskatchewan	(113.2)	124.7	215.7	(215.2)
Southern Alberta	(61.1)	67.3	118.2	(118.3)
Northern Alberta	(0.3)	0.3	0.6	(0.6)
Increase (decrease)	(439.7)	484.1	824.3	(820.8)

2018 Impairment

For the year ended December 31, 2018, the decrease in the value of the Company's market capitalization as compared to shareholders' equity was an indicator of impairment. As a result, impairment and recovery testing were required 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, 2018:

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029 [2]
WTI ($US/bbl) [1]	58.58	64.60	68.20	71.00	72.81	74.59	76.42	78.40	79.98	81.59	83.22
Exchange Rate ($US/$Cdn)	0.757	0.782	0.797	0.803	0.807	0.808	0.808	0.808	0.808	0.808	0.808
WTI ($Cdn/bbl)	77.38	82.61	85.57	88.42	90.22	92.31	94.58	97.03	98.99	100.98	103.00
AECO ($Cdn/MMbtu) [1]	1.88	2.31	2.74	3.05	3.21	3.31	3.39	3.46	3.54	3.62	3.70

(1) 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.

(2) Forecast benchmark commodity prices are assumed to increase by 2.0% in each year after 2029 to the end of the reserve life. Exchange rates are assumed to be constant at 0.808.

At December 31, 2018, the Company determined that the carrying amount of all CGUs exceeded their recoverable amount. The full amount of the impairments were attributed to PP&E and, as a result, impairment losses of $3.70 billion were recorded as a component of depletion, depreciation, amortization and impairment expense.

The following table summarizes the impairment expense for the year ended December 31, 2018 by CGU:

CGU ($ millions, except %)	**Operating segment**	**Recoverable amount**	**Discount rate**	**Impairment**	**Impairment, net of tax**
Southeast Saskatchewan	Canada	5,250.6	15.00%	1,782.1	1,300.9
Utah	U.S.	931.7	18.00%	873.5	658.4
Southwest Saskatchewan	Canada	1,975.2	15.00%	549.4	401.1
Southern Alberta [1]	Canada	872.7	15.00%	404.8	295.5
Northern U.S.	U.S.	878.7	15.00%	83.8	63.2
Northern Alberta	Canada	3.9	15.00%	11.2	8.2
Total impairment [2]		9,912.8		3,704.8	2,727.3

(1) At September 30, 2018, the Company classified certain non-core assets as held for sale. Immediately before classifying the assets as held for sale, the Company conducted a review of the assets' recoverable amounts and recorded an impairment loss of $14.1 million related to PP&E.

(2) At December 31, 2018, accumulated after tax impairment losses, net of depletion had no impairment loss been recognized in prior periods for the Canada and U.S. operating segments were $3.29 billion and $879.9 million, respectively.

Impairments were recognized in all CGUs largely due to the increase in discount rates used in impairment testing, reflecting a higher weighted average cost of capital at December 31, 2018 compared to December 31, 2017 and current market conditions in the Canadian energy sector.

Changes in any of the key judgments, such as a revision in reserves, changes in forecast benchmark commodity prices, foreign exchange rates, capital or operating costs would impact the recoverable amounts of assets and any recoveries or impairment charges would affect net income. The following sensitivities show the resulting impact on income before tax of the changes in discount rate and forecast benchmark commodity price estimates at December 31, 2018, with all other variables held constant:

CGU	Discount Rate		Commodity Prices	
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%
Southeast Saskatchewan	(350.2)	385.5	640.6	(639.8)
Utah	(46.8)	53.8	140.7	(111.0)
Southwest Saskatchewan	(135.8)	149.7	240.9	(240.6)
Southern Alberta	(70.0)	77.2	133.8	(132.5)
Northern U.S.	(57.6)	65.6	83.8	(101.0)
Northern Alberta	(0.4)	0.5	1.0	(1.0)
Increase (decrease)	(660.8)	732.3	1,240.8	(1,225.9)

9. ASSETS HELD FOR SALE

At December 31, 2019, the Company classified certain Saskatchewan gas infrastructure assets as held for sale. These assets were recorded at the lesser of their carrying value and recoverable amount, and have subsequently been disposed of in January 2020. See Note 32 - "Subsequent Events" for additional information.

($ millions)	PP&E (Note 8)	Decommissioning liability (Note 15)
Assets (liabilities) held for sale	195.0	(7.9)

10. GOODWILL

($ millions)	2019	2018
Goodwill, beginning of year	**244.0**	251.9
Southeast Saskatchewan asset dispositions	**(13.1)**	(6.2)
Other	**—**	(1.7)
Goodwill, end of year	**230.9**	244.0

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, 2019 and December 31, 2018. As a result of these tests, the Company concluded that the estimated recoverable amounts exceeded the carrying amounts and no impairments were recorded.

11. OTHER CURRENT LIABILITIES

($ millions)	2019	2018
Long-term compensation liability	**2.3**	6.5
Lease liability	**31.3**	—
Decommissioning liability	**35.0**	26.9
Lease inducement (1)	**—**	3.4
Onerous contracts provision (1)	**—**	2.6
Other current liabilities	**68.6**	39.4

(1) On adoption of IFRS 16 the Company elected to use the practical expedient to apply the previous assessment under IAS 37 for onerous contracts and deferred lease inducements. See Note 4 - "Changes in Accounting Policies" for additional information.

12. LONG-TERM DEBT

($ millions)	2019	2018
Bank debt (1)	**806.3**	1,982.1
Senior guaranteed notes (2)	**2,098.8**	2,294.6
Long-term debt	**2,905.1**	4,276.7
Long-term debt due within one year	**201.0**	99.8
Long-term debt due beyond one year	**2,704.1**	**4,176.9**

(1) The Company has London Inter-bank Offered Rate ("LIBOR") loans under its bank credit facilities. The US dollar amounts of the LIBOR loans were fixed for purposes of interest and principal repayments. At December 31, 2019, the total notional amount due upon bank debt maturity was $824.2 million (December 31, 2018 - $ 1.92 billion).

(2) The Company entered into cross currency swaps ("CCS") and a foreign exchange swap concurrent with the issuance of the US dollar senior guaranteed notes to fix the US dollar amount of the notes for the purpose of principal repayment at Canadian dollar notional amounts. At December 31, 2019, the total notional principal due on the maturity of the senior guaranteed notes was $1.82 billion (December 31, 2018 - $1.89 billion) of which $158.3 million (December 31, 2018 - $73.7 million) was due within one year.

Bank debt

The Company has combined facilities of $3.00 billion, including a $2.90 billion syndicated unsecured credit facility withfourteen banks and a $100.0 million unsecured operating credit facility with one Canadian chartered bank. The current maturity dates of the facilities is October 25, 2023. Both of these facilities constitute revolving credit facilities and are extendible annually.

The credit facilities bear interest at the applicable market rate plus a margin based on a sliding scale ratio of the Company's senior debt to earnings before interest, taxes, depletion, depreciation, amortization and impairment, adjusted for payments on lease liability and certain non-cash items including unrealized derivatives, unrealized foreign exchange, equity settled share-based compensation expense and accretion and financing expense ("adjusted EBITDA").

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, 2019.

The Company had letters of credit in the amount of $6.5 million outstanding at December 31, 2019 (December 31, 2018 - $8.0 million).

Senior guaranteed notes

The Company has closed private offerings of senior guaranteed notes raising total gross proceeds of US$1.41 billion and Cdn$270.0 million. 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	Principal Due on Maturity [1] (Cdn$ millions)	Interest Payment Dates	Maturity Date	Financial statement carrying value	
					2019	2018
Cdn$7.0	4.29%	—	November 22 and May 22	May 22, 2019	**—**	7.0
US$68.0	3.39%	—	November 22 and May 22	May 22, 2019	**—**	92.8
US$155.0	6.03%	158.3	September 24 and March 24	March 24, 2020	**201.0**	211.5
Cdn$50.0	5.53%	50.0	October 14 and April 14	April 14, 2021	**50.0**	50.0
US$82.0	5.13%	79.0	October 14 and April 14	April 14, 2021	**106.3**	111.9
US$52.5	3.29%	56.3	December 20 and June 20	June 20, 2021	**68.1**	71.6
Cdn$25.0	4.76%	25.0	November 22 and May 22	May 22, 2022	**25.0**	25.0
US$200.0	4.00%	199.1	November 22 and May 22	May 22, 2022	**259.3**	272.9
US$61.5	4.12%	80.3	October 11 and April 11	April 11, 2023	**79.7**	83.9
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	**350.1**	368.4
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	**333.8**	351.4
US$82.0	4.30%	107.0	October 11 and April 11	April 11, 2025	**106.3**	111.9
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	**298.2**	313.9
US$20.0	4.18%	25.3	October 22 and April 22	April 22, 2027	**26.0**	27.4
Senior guaranteed notes		1,817.5			**2,098.8**	2,294.6
Senior guaranteed notes due within one year					**201.0**	99.8
Senior guaranteed notes due beyond one year					**1,897.8**	2,194.8

(1) Includes underlying derivatives which manage the Company's foreign exchange exposure on its US dollar senior guaranteed notes. The Company considers this to be the economic amount due at maturity instead of the financial statement carrying amount.

Concurrent with the issuance of US$1.38 billion senior guaranteed notes, the Company entered into CCS to manage the Company's foreign exchange risk. The CCS fix the US dollar amount of the notes for purposes of interest and principal repayments at a notional amount of $1.52 billion. Concurrent with the issuance of US$30.0 million senior guaranteed notes, the Company entered a foreign exchange swap which fixed the principal repayment at a notional amount of $32.2 million. See Note 26 - “Financial Instruments and Derivatives” for additional information.

13. LEASES

Right-of-use asset

The following table reconciles the ROU asset by class as at December 31, 2019:

($ millions)	Office [1]	Fleet Vehicles	Other	Total
ROU asset at cost	120.1	17.0	10.9	148.0
Accumulated depreciation	(14.8)	(7.0)	(2.7)	(24.5)
Net carrying amount	105.3	10.0	8.2	123.5
Reconciliation of movements during the year				
Cost, beginning of year	127.7	15.9	9.7	153.3
Accumulated depreciation, beginning of year	—	—	—	—
Net carrying amount, beginning of year	127.7	15.9	9.7	153.3
Net carrying amount, beginning of year	127.7	15.9	9.7	153.3
Additions	—	3.4	2.1	5.5
Dispositions	—	(2.2)	(0.9)	(3.1)
Depreciation	(14.8)	(7.0)	(2.7)	(24.5)
Lease modification	(7.5)	—	—	(7.5)
Foreign exchange	(0.1)	(0.1)	—	(0.2)
Net carrying amount, end of year	105.3	10.0	8.2	123.5

(1) A portion of the Company's office space is subleased. During the year ended December 31, 2019, the Company recorded sublease income of $6.2 million as a component of other loss.

Lease liability

($ millions)	December 31, 2019
Lease liability, beginning of year	**223.8**
Additions	**5.5**
Dispositions	**(3.0)**
Financing	**8.9**
Payments on lease liability	**(34.1)**
Lease modification	**(19.7)**
Foreign exchange	**(0.2)**
Lease liability, end of year	**181.2**
Expected to be incurred within one year	**31.3**
Expected to be incurred beyond one year	**149.9**

Some leases contain variable payments that are not included within the lease liability as they are based on amounts determined by the lessor annually and not dependent on an index or rate. For the year ended December 31, 2019, variable lease payments of $5.2 million were included in general and administrative expenses relating to property tax payments on office leases.

During the year ended December 31, 2019, the Company recorded $1.3 million in general and administrative expenses related to short-term leases and leases for low dollar value underlying assets.

The undiscounted cash flows relating to the lease liability are as follows:

($ millions)	December 31, 2019
1 year	**36.7**
2 to 3 years	**48.6**
4 to 5 years	**38.2**
More than 5 years	**94.2**
Total [1]	**217.7**

(1) Includes both the principal and amounts representing interest.

14. OTHER LONG-TERM LIABILITIES

($ millions)	2019	2018
Long-term compensation liability [1]	**10.8**	3.5
Lease inducement [2]	**—**	36.4
Onerous contracts provision [2]	**—**	8.4
Other long-term liabilities	**10.8**	48.3

(1) Long-term compensation liability relates to share-based compensation. See Note 24 - "Share-based Compensation" for additional information.

(2) On adoption of IFRS16, the Company elected to use the practical expedient to apply the previous assessment under IAS 37 for onerous contracts and deferred lease inducements. See Note 4 - "Changes in Accounting Policies" for additional information.

15. DECOMMISSIONING LIABILITY

($ millions)	2019	2018
Decommissioning liability, beginning of year	**1,230.7**	1,344.2
Liabilities incurred	**30.7**	38.6
Liabilities acquired through capital acquisitions	**0.7**	0.4
Liabilities disposed through capital dispositions	**(223.6)**	(68.3)
Liabilities settled	**(28.7)**	(25.3)
Revaluation of acquired decommissioning liabilities [1]	**0.9**	0.6
Change in estimated future costs	**6.2**	(79.9)
Change in discount rate	**115.3**	(20.2)
Accretion expense	**23.5**	30.6
Reclassified as liabilities associated with assets held for sale	**(7.9)**	—
Foreign exchange	**(3.8)**	10.0
Decommissioning liability, end of year	**1,144.0**	1,230.7
Expected to be incurred within one year	**35.0**	26.9
Expected to be incurred beyond one year	**1,109.0**	1,203.8

(1) 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 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 $1.14 billion at December 31, 2019 (December 31, 2018 -$1.23 billion) based on total estimated undiscounted and uninflated cash flows to settle the obligation of $1.09 billion (December 31, 2018 - $1.29 billion). These obligations are expected to be settled through 2053, with the majority expected after 2036. The estimated cash flows have been discounted using a risk free rate of approximately 1.75 percent and an inflation rate of 2 percent (December 31, 2018 - approximately 2.25 percent and 2 percent, respectively).

16. SHAREHOLDERS' CAPITAL

Crescent Point has an unlimited number of common shares authorized for issuance.

	2019		2018	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Common shares, beginning of year	**550,151,561**	**16,803.0**	545,794,384	16,745.7
Issued on redemption of restricted shares	**3,321,362**	**24.7**	4,357,177	57.3
Common shares repurchased	**(24,073,000)**	**(122.6)**	—	—
Common shares, end of year	**529,399,923**	**16,705.1**	550,151,561	16,803.0
Cumulative share issue costs, net of tax	**—**	**(256.1)**	—	(256.1)
Total shareholders' capital, end of year	**529,399,923**	**16,449.0**	550,151,561	16,546.9

Normal Course Issuer Bid ("NCIB")

On January 23, 2019, 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 38,424,678 common shares, or seven percent of the Company's public float, as at January 14, 2019. The NCIB commenced on January 25, 2019 and expired on January 24, 2020.

During the year ended December 31, 2019, the Company purchased and cancelled 24.1 million common shares for total consideration of $122.6 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.

As of the date of this report, the Company has purchased, for cancellation, 26.2 million common shares for total consideration of $135.3 million.

17. DEFICIT

($ millions)	2019	2018
Accumulated earnings (deficit)	**(4,028.3)**	(2,980.6)
Accumulated gain on shares issued pursuant to DRIP [1] and SDP [2]	**8.4**	8.4
Accumulated tax effect on redemption of restricted shares	**12.1**	12.1
Accumulated dividends	**(7,629.1)**	(7,607.1)
Deficit	**(11,636.9)**	(10,567.2)

(1) Premium Dividend ™ and Dividend Reinvestment Plan.

(2) Share Dividend Plan.

18. CAPITAL MANAGEMENT

($ millions)	2019	2018
Long-term debt [1]	**2,905.1**	4,276.7
Adjusted working capital deficiency [2]	**126.1**	208.2
Unrealized foreign exchange on translation of US dollar long-term debt	**(265.9)**	(473.6)
Net debt	**2,765.3**	4,011.3
Shareholders' equity	**5,342.7**	6,612.8
Total capitalization	**8,108.0**	10,624.1

(1) Includes current portion of long-term debt.

(2) Adjusted working capital deficiency is calculated as accounts payable and accrued liabilities and long-term compensation liability, less cash, accounts receivable, prepaids and deposits and long-term investments.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations for the years ended December 31, 2019 and December 31, 2018:

($ millions)	2019	2018
Cash flow from operating activities	**1,742.9**	1,748.0
Changes in non-cash working capital	**47.5**	(37.2)
Transaction costs	**6.3**	5.1
Decommissioning expenditures	**28.7**	25.3
Adjusted funds flow from operations	**1,825.4**	1,741.2

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 and monitors its capital structure and short-term financing requirements using a measure not defined in IFRS, 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. 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 making decisions regarding financing, capital spending and dividend levels. The Company's net debt to adjusted funds flow from operations ratio at December 31, 2019 was 1.5 times (December 31, 2018 - 2.3 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, 2019. See Note 12 - "Long-term Debt" for additional information regarding the Company's financial covenant requirements.

19. COMMODITY DERIVATIVE GAINS (LOSSES)

($ millions)	2019	2018
Realized gains (losses)	**43.4**	(259.8)
Unrealized gains (losses)	**(104.4)**	203.4
Commodity derivative losses	**(61.0)**	(56.4)

20. OTHER INCOME (LOSS)

($ millions)	2019	2018
Long-term investments	**(2.0)**	(15.5)
Loss on capital dispositions	**(199.2)**	(129.1)
Lease modification	**12.2**	—
Settlement proceeds	**22.9**	—
Other	**6.2**	1.1
Other income (loss)	**(159.9)**	(143.5)

21. INTEREST EXPENSE

($ millions)	2019	2018 [1] (Revised)
Realized		
Interest expense on long-term debt	**146.8**	184.4
Unrealized (gain) loss		
CCS - Interest	**23.6**	(20.7)
Interest expense	**170.4**	163.7

(1) Comparative period revised to reflect current period presentation. Unrealized derivative gain (loss) on interest rate contracts previously included in derivative gains (losses).

22. FOREIGN EXCHANGE GAIN (LOSS)

($ millions)	2019	2018 [1] (Revised)
Realized gain (loss)		
CCS - Principal	**32.4**	88.3
US dollar long-term debt maturities	**(32.4)**	(70.3)
Other	**(3.7)**	4.3
Unrealized gain (loss)		
CCS - Principal and foreign exchange swaps	**(141.6)**	215.3
Translation of US dollar long-term debt	**207.7**	(254.2)
Other	**(1.3)**	(2.1)
Foreign exchange gain (loss) [1]	**61.1**	(18.7)

(1) Comparative period revised to reflect current period presentation. Unrealized derivative gain (loss) on CCS and foreign exchange swaps previously included in derivative gains (losses).

23. INCOME TAXES

The provision for income taxes is as follows:

($ millions)	2019	2018
Current tax:		
Canada	**0.2**	—
Luxembourg	**0.2**	0.3
Current tax expense	**0.4**	0.3
Deferred tax expense (recovery):		
Canada	**(225.6)**	(690.5)
United States	**66.2**	(248.3)
Deferred tax recovery	**(159.4)**	(938.8)
Income tax recovery	**(159.0)**	(938.5)

The following table reconciles income taxes calculated at the Canadian statutory rate with the recorded income taxes:

($ millions)	**2019**	2018
Net income (loss) before tax	**(1,192.3)**	(3,555.4)
Statutory income tax rate	**26.81%**	27.00%
Expected provision for income taxes	**(319.7)**	(960.0)
Change in corporate tax rates and tax rate variance	**18.6**	—
Tax rates in foreign jurisdictions	**(5.3)**	13.9
Restricted share bonus plan	**3.9**	1.8
Change in recognition of deferred tax assets	**108.3**	(1.1)
Recognition of capital gain on intercompany debt	**18.5**	—
Non-deductible capital losses	**4.3**	0.6
Non-deductible impairment of goodwill	**3.5**	2.1
Other	**8.9**	4.2
Income tax recovery	**(159.0)**	(938.5)

The statutory combined federal and provincial income tax rate decreased from 27 percent in 2018 to 26.81 percent in 2019 primarily due to the decrease in the Alberta corporate tax rate from 12 percent to 11 percent, effective July 1, 2019.

On June 28, 2019, the Alberta government enacted legislation which reduces the Alberta corporate income tax rate from 12 percent to 8 percent over the period of July 1, 2019 through January 1, 2022. As a result of these changes in tax rates, the Company recognized a reduction of $5.0 million in its deferred income tax asset.

The net deferred income tax assets (liabilities) are expected to be settled in the following periods:

($ millions)	**2019**	2018
Deferred income tax:		
To be settled within one year	**3.5**	(57.9)
To be settled beyond one year	**741.8**	660.2
Deferred income tax	**745.3**	602.3

The movement in deferred income tax assets (liabilities) are as follows:

($ millions)	At January 1, 2019	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	**At December 31, 2019**
Deferred income tax assets:				
Decommissioning liability	329.6	—	(38.4)	**291.2**
Income tax losses carried forward	918.1	—	14.5	**932.6**
Share issue costs	5.3	—	(2.8)	**2.5**
Risk management contracts	—	—	4.7	**4.7**
Lease liabilities	—	58.4	(11.9)	**46.5**
Other	16.3	(35.3)	25.6	**6.6**
	1,269.3	23.1	(8.3)	**1,284.1**
Deferred income tax liabilities:				
Property, plant and equipment	(633.9)	—	158.0	**(475.9)**
Risk management contracts	(33.1)	—	17.1	**(16.0)**
ROU asset	—	(39.5)	7.8	**(31.7)**
Other	—	—	(15.2)	**(15.2)**
	(667.0)	(39.5)	167.7	**(538.8)**
Net deferred income tax assets (liabilities)	602.3	(16.4)	159.4	**745.3**

($ millions)	At January 1, 2018	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	At December 31, 2018
Deferred income tax assets:				
Decommissioning liability	361.3	—	(31.7)	329.6
Income tax losses carried forward	649.5	—	268.6	918.1
Share issue costs	10.2	—	(4.9)	5.3
Risk management contracts	33.5	—	(33.5)	—
Other	22.2	21.3	(27.2)	16.3
	1,076.7	21.3	171.3	1,269.3
Deferred income tax liabilities:				
Property, plant and equipment	(1,417.5)	—	783.6	(633.9)
Risk management contracts	(17.0)	—	(16.1)	(33.1)
	(1,434.5)	—	767.5	(667.0)
Net deferred income tax assets (liabilities)	(357.8)	21.3	938.8	602.3

The approximate amounts of tax pools available as at December 31, 2019 and 2018 are as follows:

($ millions)	**2019**	2018
Tax pools:		
Canada	**7,691.8**	8,389.0
United States	**2,975.9**	3,830.0
Total	**10,667.7**	12,219.0

Deferred tax assets are recognized to the extent of expected utilization of tax attributes, based on estimated undiscounted future cashflows included in the Company's independent reserve report.

The above tax pools include estimated Canadian non-capital losses carried forward of $1.95 billion (December 31, 2018 - $1.90 billion) that expire in the years 2026 through 2039, and U.S. net operating losses of $2.26 billion (December 31, 2018 - $1.73 billion) of which $1.63 billion will expire in the years 2029 through 2037, while the remaining $630.6 million will not expire. A deferred income tax asset has not been recognized for U.S. net operating losses of $341.4 million (December 31, 2018 - $89.7 million) or for other temporary differences of $69.0 million (December 31, 2018 - $56.2 million) as there is not sufficient certainty regarding future utilization.

At December 31, 2019, 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 $1.6 billion (December 31, 2018 - $1.3 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 in response to these reassessments and management believes that it will be successful in defending its positions. Therefore, no provision for the potential income tax liability was recorded at December 31, 2019 and December 31, 2018.

24. SHARE-BASED COMPENSATION

Restricted Share Bonus Plan

The Company has a Restricted Share Bonus Plan pursuant to which the Company may grant restricted shares to directors, officers, employees and consultants. The restricted shares vest on terms up to three years from the grant date as determined by the Board of Directors. Restricted shares are settled upon vesting, at the Company's discretion, in common shares or cash. The expense is recognized over the service period and is included in shareholder's equity.

Performance Share Unit Plan

The Company has a PSU Plan for designated employees. The PSUs vest on terms up to three years from the grant date as determined by the Board of Directors. PSUs are settled in cash upon vesting based on the prevailing Crescent Point share price, accrued dividends and performance multipliers. The expense is recognized over the service period and is included in long-term compensation liability.

Deferred Share Unit Plan

The Company has a DSU Plan for directors. Each DSU vests on the date of the grant, however, the settlement of the DSU occurs following a change of control or when the individual ceases to be a director of the Company. DSUs are settled in cash based on the prevailing Crescent Point share price. The expense is recognized at fair value at each period end and is included in long-term compensation liability.

The following table reconciles the number of restricted shares, PSUs and DSUs for the year ended December 31, 2019:

	Restricted Shares	PSUs [1]	DSUs
Balance, beginning of year	3,241,684	2,246,314	301,614
Granted	4,482,755	2,607,826	239,030
Redeemed	(3,504,004)	(1,630,736)	(220,753)
Forfeited	(584,241)	(302,960)	—
Balance, end of year	3,636,194	2,920,444	319,891

(1) Based on underlying units before any effect of performance multipliers.

The following table reconciles the number of restricted shares, PSUs and DSUs for the year ended December 31, 2018:

	Restricted Shares	PSUs [1]	DSUs
Balance, beginning of year	3,589,024	4,460,046	229,470
Granted	5,219,156	1,238,518	118,999
Redeemed	(4,557,768)	(2,839,865)	(46,855)
Forfeited	(1,008,728)	(612,385)	—
Balance, end of year	3,241,684	2,246,314	301,614

(1) Based on underlying units before any effect of performance multipliers.

Stock Option Plan

The Company has a Stock Option Plan for designated employees. The Options 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 vest, 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.

The following tables provide summary information regarding stock options outstanding as at December 31, 2019:

	Stock Options (number of units)	Weighted average exercise price ($)
Balance, beginning of year	2,048,115	10.03
Granted	1,221,025	4.03
Forfeited	(374,673)	8.94
Expired	(61,125)	10.06
Balance, end of year	2,833,342	7.59

The following tables provide summary information regarding stock options outstanding as at December 31, 2018:

	Stock Options (number of units)	Weighted average exercise price ($)
Balance, beginning of year	—	—
Granted	3,158,490	10.04
Forfeited	(1,110,375)	10.06
Balance, end of year	2,048,115	10.03

The following table summarizes information regarding stock options outstanding as at December 31, 2019:

Number of stock options outstanding	Weighted average exercise price per share for options outstanding ($)	Vest year	Weighted average remaining term (years)	Number of stock options exercisable	Weighted average exercise price per share for options exercisable ($)
356,698	10.02	2019	5.05	356,698	10.02
600,903	7.59	2020	5.54	—	—
549,610	7.55	2021	5.56	—	—
872,307	8.46	2022	5.37	—	—
453,824	4.04	2023	6.27	—	—

The Company estimates the fair value of stock options on the date of the grant using a Black-Scholes option pricing model. The following weighted average assumptions were used to estimate the fair value of the stock options at their grant date:

	2019	2018
Grant date share price ($)	**4.03**	10.04
Exercise price ($)	**4.03**	10.04
Expected annual dividends ($)	**0.04**	0.36
Expected volatility (%)	**40.11%**	35.90%
Risk-free interest rate (%)	**1.64%**	2.00%
Expected life of stock option	**4.9 years**	4.9 years
Fair value per stock option ($)	**1.36**	2.34

For the year ended December 31, 2019, the Company calculated total share-based compensation of$29.2 million (year ended December 31, 2018 -$53.7 million), net of estimated forfeitures, of which $4.3 million was capitalized (year ended December 31, 2019 -$7.7 million).

At December 31, 2019, the current portion of long-term compensation liability of$2.3 million was included in other current liabilities (December 31, 2018 - $6.5 million) and $10.8 million was included in other long-term liabilities (December 31, 2018 -$3.5 million).

25. PER SHARE AMOUNTS

The following table summarizes the weighted average shares used in calculating net income per share:

	2019	2018
Weighted average shares – basic	**545,674,158**	549,109,960
Dilutive impact of share-based compensation	**—**	—
Weighted average shares – diluted [(1)]	**545,674,158**	549,109,960

(1) Excludes the impact of 310,288 weighted average shares related to share-based compensation that were anti-dilutive for the year ended December 31, 2019 (year ended December 31, 2018 - 1,086,922).

26. FINANCIAL INSTRUMENTS AND DERIVATIVES

The Company's financial assets and liabilities are comprised of cash, accounts receivable, long-term investments, derivative assets and liabilities, accounts payable and accrued liabilities and long-term debt.

Crescent Point's derivative assets and liabilities are transacted in active markets. Crescent Point's long-term investments can be transacted in active and non-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. Long-term investments are classified as Level 1, Level 2 or Level 3 depending on the valuation methods and inputs used and whether the applicable company is publicly traded or private. 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, and accounts payable and accrued liabilities 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.

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, 2019:

($ millions)	2019 Carrying Value	2019 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	327.9	327.9	—	327.9	—
Long-term investments [1]	6.7	6.7	6.7	—	—
	334.6	334.6	6.7	327.9	—
Financial liabilities					
Derivatives	18.4	18.4	—	18.4	—
Senior guaranteed notes [2]	2,098.8	2,120.1	—	2,120.1	—
	2,117.2	2,138.5	—	2,138.5	—

(1) Long-term investments are comprised of equity securities in public oil and gas companies.

(2) 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, 2018:

($ millions)	2018 Carrying Value	2018 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	595.6	595.6	—	595.6	—
Long-term investments [1]	8.7	8.7	8.7	—	—
	604.3	604.3	8.7	595.6	—
Financial liabilities					
Senior guaranteed notes [2]	2,294.6	2,273.5	—	2,273.5	—
	2,294.6	2,273.5	—	2,273.5	—

(1) Long-term investments are comprised of equity securities in public oil and gas companies.

(2) 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. 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, 2019 and the change in fair value for the year ended December 31, 2019:

($ millions)	Commodity contracts [1]	Interest contracts	CCS contracts [2]	Foreign exchange contracts	Total
Derivative assets, beginning of year	147.0	5.5	434.7	8.4	595.6
Disposed	(16.2)	—	—	—	(16.2)
Unrealized change in fair value	(104.4)	(2.7)	(160.7)	(1.8)	(269.6)
Foreign exchange	(0.3)	—	—	—	(0.3)
Derivative assets, end of year	26.1	2.8	274.0	6.6	309.5
Derivative assets, end of year	26.1	2.8	292.2	6.8	327.9
Derivative liabilities, end of year	—	—	(18.2)	(0.2)	(18.4)

(1) Includes oil and gas contracts.

(2) Includes mark-to-market on principal and interest.

The following table summarizes the fair value as at December 31, 2018 and the change in fair value for the year ended December 31, 2018:

($ millions)	Commodity contracts [1]	Interest contracts	CCS contracts	Foreign exchange contracts	Total
Derivative assets / (liabilities), beginning of year	(53.8)	9.5	198.0	5.1	158.8
Unrealized change in fair value	203.4	(4.0)	236.7	3.3	439.4
Foreign exchange	(2.6)	—	—	—	(2.6)
Derivative assets, end of year	147.0	5.5	434.7	8.4	595.6

(1) Includes oil and gas 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, 2019 and December 31, 2018:

			2019			2018
($ millions)	Asset	Liability	Net	Asset	Liability	Net
Gross amount	334.5	(25.0)	309.5	595.6	—	595.6
Amount offset	(6.6)	6.6	—	—	—	—
Net amount	327.9	(18.4)	309.5	595.6	—	595.6

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 and foreign exchange rates as well as credit and liquidity risk.

Commodity price risk

The Company is exposed to commodity price risk on crude oil, NGLs and natural gas revenues as well as power on electricity consumption.

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, with all other variables held constant:

	Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Year ended December 31, 2019		Year ended December 31, 2018	
	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Commodity price				
Crude oil	(117.1)	104.2	(75.6)	61.6
Natural gas	—	—	(0.7)	0.7

Interest rate risk

The Company is exposed to interest rate risk on bank credit facilities to the extent of changes in market interest rates. Based on the Company's floating rate debt position as at December 31, 2019, a 1 percent increase or decrease in the interest rate on floating rate debt would amount to an impact on income before tax of $5.1 million (December 31, 2018 - $16.1 million).

The following table summarizes the unrealized gains (losses) on the Company's interest derivative contracts and the resulting impact on income before tax due to the respective changes in the applicable forward interest rates, with all other variables held constant:

	Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Year ended December 31, 2019		Year ended December 31, 2018	
Forward interest rates	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Interest rate swaps	0.5	(0.5)	1.1	(1.1)

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 in relation to its crude oil sales. Crescent Point enters into various CCS and foreign exchange swaps to hedge its foreign exchange exposure on its US dollar denominated long-term debt. To partially mitigate the foreign exchange risk relating to crude oil sales, the Company has fixed crude oil contracts to settle in Cdn$ WTI.

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, 2019		Year ended December 31, 2018	
Cdn$ relative to US$		Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
US dollar long-term debt	Period End	254.8	(254.8)	394.2	(394.2)
Cross currency swaps	Forward	(264.6)	264.6	(402.3)	402.3
Foreign exchange swaps	Forward	(2.0)	2.0	(9.4)	9.4

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 and third party credit insurance. Including these assurances, approximately 95 percent of the Company's oil and gas sales are with entities considered investment grade.

At December 31, 2019, approximately 5 percent (December 31, 2018 - 5 percent) of the Company's accounts receivable balance was outstanding for more than 90 days and the Company's average expected credit loss was 0.60 percent (December 31, 2018 - 2.95 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 arrangements as well as other potential sources of capital.

At December 31, 2019, the Company had available unused borrowing capacity on bank credit facilities of approximately $2.24 billion, including $6.5 million outstanding letters of credit and cash of $56.9 million.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2019 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	479.4	—	—	—	479.4
Senior guaranteed notes [(1)]	234.6	532.3	829.2	500.5	2,096.6
Bank credit facilities [(2)]	39.9	916.8	—	—	956.7

(1) 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.

(2) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2019 and includes undiscounted cash outflows pursuant to the CCS related to LIBOR loans. The current maturity date of the Company's facilities is October 25, 2023. The Company expects that the facilities will continue to be renewed and extended prior to their maturity dates.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding as at December 31, 2018 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	549.4	—	—	—	549.4
Senior guaranteed notes [1]	156.9	486.7	767.0	843.1	2,253.7
Bank credit facilities [2]	108.2	2,128.7	—	—	2,236.9

(1) 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.

(2) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2018 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, 2019:

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar [1]

	Swap		Three-way Collar			
Term	Volume (bbls/d)	Average Price ($/bbl)	Volume (bbls/d)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)	Average Sold Put Price ($/bbl)
2020	14,249	75.52	39,730	82.67	76.48	62.72
2021 January - March	—	—	5,000	78.87	73.50	63.50

(1) The volumes and prices reported are the weighted average volumes and prices for the period.

Financial Interest Rate Derivative Contracts – Canadian Dollar

Term	Contract	Notional Principal ($ millions)	Fixed Rate (%)
January 2020 - August 2020	Swap	50.0	1.16
January 2020 - August 2020	Swap	50.0	1.16
January 2020 - August 2020	Swap	100.0	1.15
January 2020 - September 2020	Swap	50.0	1.14
January 2020 - September 2020	Swap	50.0	1.11

Financial Cross Currency Derivative Contracts

Term	Contract	Receive Notional Principal (US$ millions)	Fixed Rate (US%)	Pay Notional Principal (Cdn$ millions)	Fixed Rate (Cdn%)
January 2020	Swap	555.0	3.50	737.4	3.31
January 2020 - March 2020	Swap	155.0	6.03	158.3	6.45
January 2020 - April 2021	Swap	82.0	5.13	79.0	5.83
January 2020 - June 2021	Swap	52.5	3.29	56.3	3.59
January 2020 - May 2022	Swap	170.0	4.00	166.9	5.03
January 2020 - April 2023	Swap	61.5	4.12	80.3	3.71
January 2020 - June 2023	Swap	270.0	3.78	274.7	4.32
January 2020 - June 2024	Swap	257.5	3.75	276.4	4.03
January 2020 - April 2025	Swap	82.0	4.30	107.0	3.98
January 2020 - April 2025	Swap	230.0	4.08	291.1	4.13
January 2020 - April 2027	Swap	20.0	4.18	25.3	4.25

Financial Foreign Exchange Forward Derivative Contracts

Settlement Date	Contract	Receive Notional Principal (US$ millions)	Pay Notional Principal (Cdn$ millions)
January 2020	Swap	15.0	19.7
May 2022	Swap	30.0	32.2

27. RELATED PARTY TRANSACTIONS

Compensation of key management personnel

Key management personnel of the Company include its directors and executive officers. In 2019, the Company recorded $5.8 million (2018 - $7.7 million) relating to compensation of key management personnel and $2.3 million (2018 - $11.3 million) for severance relating to key management personnel. In 2019, share-based compensation costs relating to compensation of key management personnel and severance were $10.3 million (2018 - $22.6 million) and nil (2018 - $2.8 million), respectively.

28. COMMITMENTS

At December 31, 2019, 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]	5.6	9.7	11.7	37.9	64.9
Transportation	15.4	24.4	23.7	12.8	76.3
Capital	4.8	—	—	—	4.8
Total contractual commitments [2]	25.8	34.1	35.4	50.7	146.0

(1) Includes operating costs on the Company's office space, net of $14.3 million recoveries from subleases

(2) Excludes contracts accounted for under IFRS 16. See Note 13 - "Leases" for additional information.

At December 31, 2018, 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 (building, vehicle and equipment) [1]	35.3	64.5	54.3	194.5	348.6
Transportation	16.3	24.8	22.7	26.2	90.0
Total contractual commitments	51.6	89.3	77.0	220.7	438.6

(1) Included in operating leases are recoveries of rent expense on office space the Company has subleased of $44.8 million.

29. SIGNIFICANT SUBSIDIARIES

The Company has the following significant subsidiaries, each owned 100% directly and indirectly, at December 31, 2019:

Subsidiary Name	Country of Incorporation
Crescent Point Resources Partnership	Canada
Crescent Point Holdings Inc.	Canada
Crescent Point Energy U.S. Corp.	United States of America
Crescent Point U.S. Holdings Corp.	United States of America
Crescent Point Energy Lux S.à r.l.	Luxembourg

30. 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)	**2019**	2018
Operating	**76.6**	96.3
General and administrative	**72.8**	88.8
Share-based compensation	**24.9**	46.0
Total compensation expenses	**174.3**	231.1

Cash flow statement presentation

($ millions)	**2019**	2018
Operating activities		
Changes in non-cash working capital:		
Accounts receivable	**(31.8)**	89.8
Prepaids and deposits	**(2.4)**	—
Accounts payable and accrued liabilities	**(16.5)**	(39.6)
Other current liabilities	**(4.1)**	(11.5)
Other long-term liabilities	**7.3**	(1.5)
	(47.5)	37.2
Investing activities		
Changes in non-cash working capital:		
Accounts receivable	**54.1**	(25.0)
Accounts payable and accrued liabilities	**(12.9)**	(56.6)
	41.2	(81.6)
Financing activities		
Changes in non-cash working capital:		
Accounts payable and accrued liabilities	**(11.2)**	(0.3)

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] [3]
December 31, 2018	**16.5**	**4,276.7**	**223.8**
Changes from cash flow from financing activities:			
Decrease in bank debt, net		**(1,099.2)**	
Repayment of senior guaranteed notes		**(98.2)**	
Realized gain on cross currency swap maturity		**32.4**	
Cash dividends paid	**(33.2)**		
Payments on lease liability			**(34.1)**
Non-cash changes:			
Cash dividends declared	**22.0**		
Financing			**8.9**
Additions			**5.5**
Dispositions			**(3.0)**
Lease modification			**(19.7)**
Foreign exchange		**(206.6)**	**(0.2)**
December 31, 2019	**5.3**	**2,905.1**	**181.2**
December 31, 2017	16.8	4,111.0	—
Changes from cash flow from financing activities:			
Decrease in bank debt, net		(360.0)	
Issuance of senior guaranteed notes		267.3	
Repayment of senior guaranteed notes		(65.0)	
Realized gain on cross currency swap maturity		70.3	
Cash dividends paid	(198.8)		
Non-cash changes:			
Cash dividends declared	198.5		
Foreign exchange		253.1	
December 31, 2018	16.5	4,276.7	—

(1) Includes current portion of long-term debt.

(2) Includes current portion of lease liability.

(3) Lease liability is as at January 1, 2019. See Note 4 - "Changes in Accounting Policies" for additional information.

31. GEOGRAPHICAL DISCLOSURE

The following table reconciles oil and gas sales by country and product type:

($ millions) [1]	**2019**	2018
Canada		
Crude oil sales	**2,425.3**	2,743.6
NGL sales	**116.8**	202.1
Natural gas sales	**63.9**	54.3
Total Canada	**2,606.0**	3,000.0
U.S.		
Crude oil sales	**667.9**	811.7
NGL sales	**34.2**	41.2
Natural gas sales	**27.9**	34.6
Total U.S.	**730.0**	887.5
Total oil and gas sales	**3,336.0**	3,887.5

(1) Oil and gas sales are reported before realized derivatives .

The following table reconciles non-current assets by country:

($ millions)	**2019**	2018
Canada	**8,121.9**	9,679.1
U.S.	**1,338.4**	2,464.7
Total	**9,460.3**	12,143.8

32. SUBSEQUENT EVENTS

Gas infrastructure assets disposition

On January 20, 2020, Crescent Point closed the sale of certain gas infrastructure assets in Saskatchewan for total cash consideration of $500.0 million.

Directors

Barbara Munroe, Chair [6]

Laura Cillis [1] [2]

James Craddock [1] [3] [5]

John Dielwart [3] [4]

Ted Goldthorpe [1] [5]

Mike Jackson [1] [2] [5]

Jennifer Koury [2] [4]

Francois Langlois [3] [4] [5]

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 Environmental, Health & Safety 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

Brad Borggard
Senior Vice President, Corporate Planning and Capital Markets

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Garret Holt
Senior Vice President, Corporate Development

Head Office

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Calgary, Alberta T2P 1G1
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Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates 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

Brad Borggard
Senior Vice President, Corporate Planning and Capital Markets
(403) 693-0020

Shant Madian
Vice President, Investor Relations and Corporate Communications
(403) 693-0020

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated March 4, 2020 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2019 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, 2019 have been prepared in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standard 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 report are in Canadian dollars unless noted otherwise. References to "US$" are to United States ("U.S.") dollars.

Overview

Crescent Point's 2019 results are highlighted by continued operational execution, increased adjusted funds flow from operations and adjusted net earnings from operations, improved cost structures and a significant reduction in net debt. The Company also implemented a Normal Course Issuer Bid ("NCIB") to provide for the return of capital to shareholders through a share repurchase program.

The Company's operations were on track with production of 162,230 boe/d in 2019, in-line with guidance of 161,000-163,000 boe/d. Development capital spending totaled $1.25 billion which was in-line with guidance of $1.225 to $1.275 billion. Operating expenses were $12.29 per boe, down 6 percent from 2018 as the Company advanced cost control and efficiency initiatives including an operations by exception workflow platform in the field.

During 2019, adjusted funds flow from operations increased 5 percent to $1.83 billion and adjusted net earnings from operations increased 65 percent to $386.8 million. In the fourth quarter the Company recognized a non-cash impairment charge of $1.21 billion on its oil and gas assets, primarily due to lower forecast commodity prices, resulting in an overall net loss of $1.03 billion in 2019. Impairment charges may be reversed in future periods if there are indications of a change in value, including higher forecast commodity prices.

The Company continued to focus its asset base completing $940.0 million of asset dispositions during 2019, with the Southeast Saskatchewan and Uinta Basin dispositions accounting for the majority of the proceeds. These strategic transactions, which closed late in the third quarter and early fourth quarter respectively, meaningfully improved the Company's balance sheet and will help lower the Company's operating, royalty and general administrative expenses moving forward.

Strong operating results and proceeds from divestments allowed Crescent Point to reduce its net debt by $1.25 billion in 2019, ending the year with net debt of $2.77 billion, or 1.5 times trailing adjusted funds flow from operations. In addition, the Company was active on its share repurchase program purchasing 26.2 million common shares as of the date of this report for total consideration of $135.3 million. As a result of lower debt balances, realized interest expense was reduced by $37.6 million or 20 percent from 2018.

On January 20, 2020 the Company successfully closed the sale of certain natural gas infrastructure assets in Saskatchewan for total cash proceeds of $500 million. The proceeds were applied against debt, further strengthening the Company's financial position.

Results of Operations

Production

	2019	2018	% Change
Crude oil (bbls/d)	**126,219**	140,298	(10)
NGLs (bbls/d)	**20,746**	19,805	5
Natural gas (mcf/d)	**91,592**	108,376	(15)
Total (boe/d)	**162,230**	178,166	(9)
Crude oil and NGLs (%)	**91**	90	1
Natural gas (%)	**9**	10	(1)
Total (%)	**100**	100	—

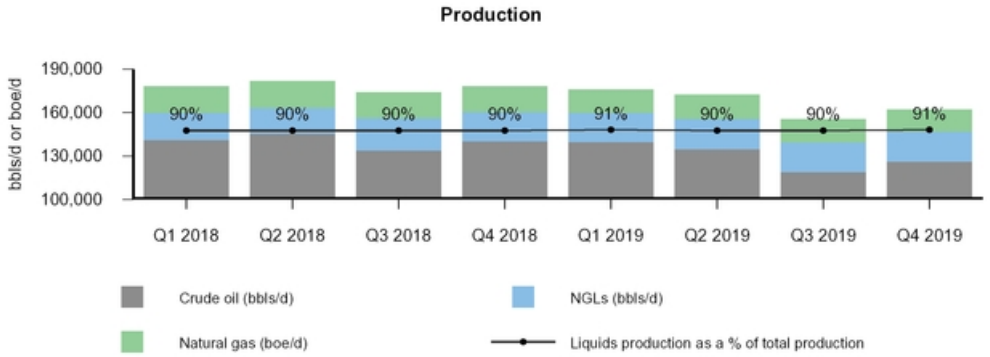
The following is a summary of Crescent Point's production by area:

Production By Area (boe/d)	**2019**	2018	% Change
Williston Basin	**97,231**	102,624	(5)
Southwest Saskatchewan	**38,378**	39,913	(4)
Uinta Basin	**16,240**	22,640	(28)
Other	**10,381**	12,989	(20)
Total	**162,230**	178,166	(9)

Total production averaged 162,230 boe/d during 2019, down 9 percent from 178,166 boe/d in 2018. Crude oil and natural gas production decreased 10 percent and 15 percent, respectively, primarily due to asset dispositions in Southeast Saskatchewan in the third quarter and the sale of the Uinta Basin assets in the fourth quarter. Natural gas liquids ("NGLs") volumes increased mainly due to growing production in North Dakota.

The Company's weighting to crude oil and NGLs remained relatively consistent with the comparative period.

Exhibit 1



Marketing and Prices

Average Selling Prices [1]	**2019**	2018	% Change
Crude oil ($/bbl)	**67.14**	69.43	(3)
NGLs ($/bbl)	**19.94**	33.66	(41)
Natural gas ($/mcf)	**2.75**	2.25	22
Total ($/boe)	**56.34**	59.78	(6)

(1) The average selling prices reported are before realized derivatives and transportation.

Benchmark Pricing	**2019**	2018	% Change
Crude Oil Prices			
WTI crude oil (US$/bbl) [1]	**57.04**	64.78	(12)
WTI crude oil (Cdn$/bbl)	**75.65**	83.91	(10)
Crude Oil Differentials			
LSB crude oil (Cdn$/bbl) [2]	**(6.03)**	(10.75)	(44)
FOS crude oil (Cdn$/bbl) [3]	**(12.79)**	(25.65)	(50)
Wax crude oil (US$/bbl) [4]	**(12.75)**	(8.97)	42
UHC crude oil (US$/bbl) [5]	**(0.66)**	(2.39)	(72)
Natural Gas Prices			
AECO daily spot natural gas (Cdn$/mcf) [6]	**1.75**	1.50	17
AECO monthly index natural gas (Cdn$/mcf)	**1.62**	1.53	6
NYMEX natural gas (US$/mmbtu) [7]	**2.63**	3.08	(15)
Foreign Exchange Rate			
Exchange rate (US$/Cdn$)	**0.754**	0.772	(2)

(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 Western Canadian Select ("WCS") prices.

(4) Wax crude oil is based on posted yellow wax prices in Salt Lake City. The crude oil differential for 2019 is based on the 10 months ended October 31, 2019, as the Uinta Basin assets were disposed of on October 18, 2019.

(5) UHC refers to the Sweet at Clearbrook crude oil price.

(6) AECO refers to the Alberta Energy Company natural gas price.

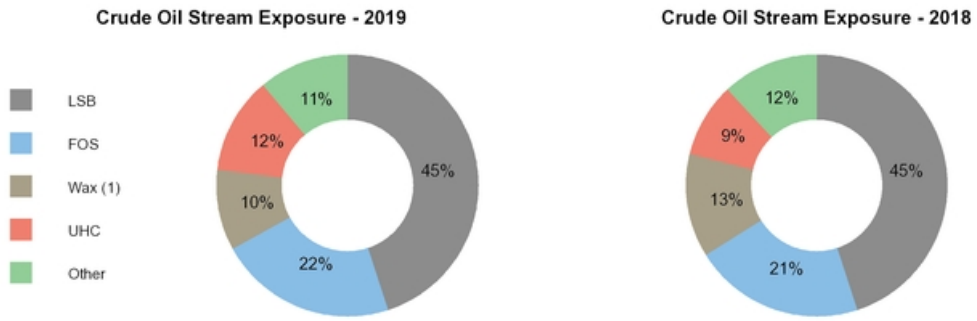
(7) NYMEX refers to the New York Mercantile Exchange natural gas price.

US$ WTI benchmark price decreased 12 percent on average in 2019. The decrease reflects increased global inventory and concerns over the state of the global economy, which put downward pressure on prices throughout the year.

Canadian natural gas prices strengthened in 2019 with the AECO daily benchmark price increasing 17 percent due to tighter natural gas supplies and shrinking inventories. In addition, TC Energy's Temporary Service Protocol enacted on the Nova Gas Transmission Limited pipeline allowed for storage during maintenance periods and reduced the volatility of AECO prices.

U.S. natural gas prices weakened in 2019 with the NYMEX benchmark price decreasing 15 percent due to continued supply growth that resulted in higher inventory levels in 2019.

Exhibit 2



(1) Utah production is priced at a negotiated discount to WTI.

Canadian crude oil differentials narrowed in 2019 primarily due to the mandatory oil production curtailments in Alberta and continued strong demand. In the U.S., yellow and black wax differentials widened due to increased supply in the Uinta Basin outpacing the local refining capacity in Salt Lake City. Overall, the Company's corporate oil differential in 2019 narrowed reflecting the quality and location of the Company's production. Additionally, the Company's production volumes were not affected by the Alberta government's mandatory production curtailment and Southeast Saskatchewan production is located downstream of apportionment points.

For the year ended December 31, 2019, the Company's average selling price for crude oil decreased 3 percent from 2018, primarily as a result of a 12 percent decrease in the US$ WTI benchmark price, partially offset by a narrower corporate oil price differential. Crescent Point's corporate oil differential relative to Cdn$ WTI for the year ended December 31, 2019 was $8.51 per bbl compared to $14.48 per bbl in 2018.

The Company's average selling price for NGLs in 2019 decreased 41 percent from $33.66 per bbl to $19.94 per bbl. Average selling prices for NGLs were impacted by the significant weakening of propane, butane and condensate prices.

The Company's average selling price for natural gas in 2019 increased 22 percent from $2.25 per mcf to $2.75 per mcf, primarily as a result of the 17 percent increase in the AECO daily benchmark price and the premium to benchmark pricing received on the Company's Saskatchewan gas production and growth in U.S. gas production which is exposed to NYMEX based pricing.

Exhibit 3

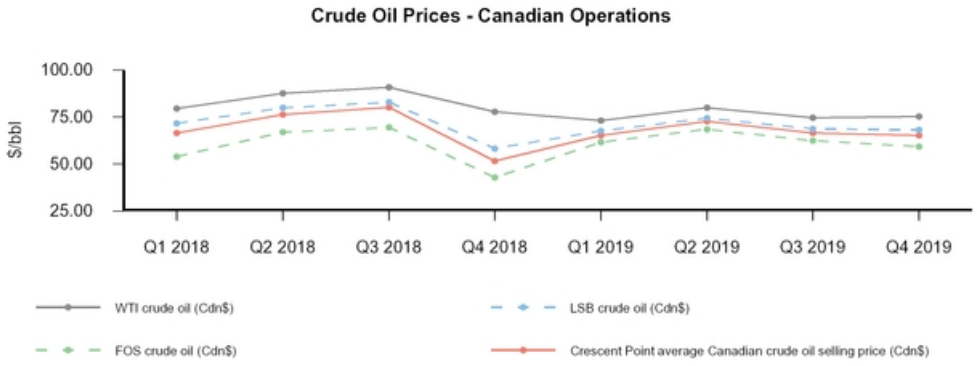
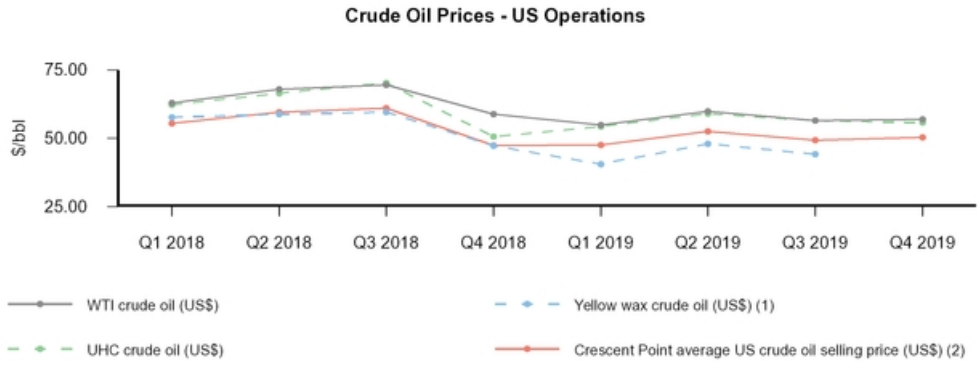


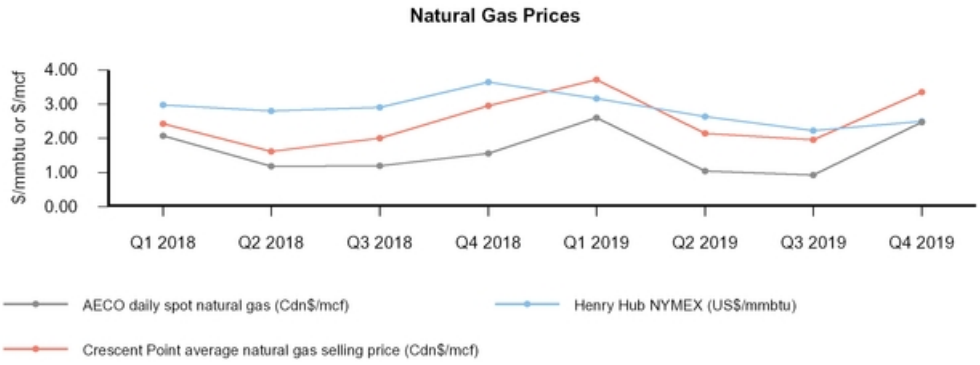
Exhibit 4



(1) Q4 2019 excludes yellow wax crude oil due to the disposition of the Uinta Basin assets in October 2019.

(2) The Company's average US crude oil selling price for Q4 2019 relates to North Dakota and excludes the Uinta Basin.

Exhibit 5



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 and reviews such conditions with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program. Crescent Point proactively manages the risk exposure inherent in movements in the price of crude oil, natural gas and power, and in fluctuations in the US/Cdn dollar exchange rate and interest rates through the use of derivatives with investment-grade counterparties.

The Company's crude oil and natural gas derivatives are referenced to WTI and the AECO monthly index, respectively, unless otherwise noted. 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 26 - "Financial Instruments and Derivatives" in the annual consolidated financial statements for the year ended December 31, 2019 for additional information on the Company's derivatives.

The following is a summary of the realized commodity derivative gains (losses):

($ millions, except volume amounts)	**2019**	2018	% Change
Average crude oil volumes hedged (bbls/d)	**62,926**	79,066	(20)
Crude oil realized derivative gain (loss)	**34.7**	(276.7)	(113)
per bbl	**0.75**	(5.40)	(114)
Average natural gas volumes hedged (GJ/d) [(1)]	**19,948**	33,973	(41)
Natural gas realized derivative gain	**8.7**	16.9	(49)
per mcf	**0.26**	0.43	(40)
Average barrels of oil equivalent hedged (boe/d)	**66,077**	84,432	(22)
Total realized derivative gains (losses)	**43.4**	(259.8)	(117)
per boe	**0.73**	(4.00)	(118)

(1) GJ/d is defined as gigajoules per day.

The Company's realized derivative gain for crude oil was $34.7 million for the year ended December 31, 2019, compared to a realized derivative loss of $276.7 million in 2018. The realized derivative gain in 2019 was largely attributable to the decrease in the Cdn$ WTI benchmark price and the increase in the Company's average derivative crude oil price. During the year ended December 31, 2019, the Company's average derivative crude oil price increased by 4 percent or $2.84 per bbl, from $74.32 per bbl in 2018 to $77.16 per bbl in 2019.

Crescent Point's realized derivative gain for gas was $8.7 million for the year ended December 31, 2019, compared to $16.9 million in 2018. The decreased realized derivative gain in 2019 was largely attributable to lower volumes hedged, an increase in the AECO monthly index price, and the decrease in the Company's average derivative gas price. During the year ended December 31, 2019, the Company's average derivative gas price decreased by 3 percent or $0.09 per GJ, from $2.82 per GJ in 2018 to $2.73 per GJ in 2019.

Exhibit 6

The following is a summary of the Company's unrealized commodity derivative gains (losses):

($ millions)	**2019**	2018	% Change
Crude oil	**(94.0)**	216.1	(143)
Natural gas	**(10.4)**	(12.7)	(18)
Total unrealized commodity derivative gains (losses)	**(104.4)**	203.4	(151)

The Company recognized a total unrealized commodity derivative loss of $104.4 million for the year ended December 31, 2019 compared to an unrealized commodity derivative gain of $203.4 million in 2018, primarily due to a $94.0 million unrealized derivative loss on crude oil contracts compared to a $216.1 million unrealized derivative gain in 2018. The unrealized crude oil derivative loss for the year ended December 31, 2019 was primarily attributable to the increase in the Cdn$ WTI forward benchmark prices at December 31, 2019 compared to December 31, 2018.

Oil and Gas Sales

($ millions) [1]	**2019**	2018	% Change
Crude oil sales	**3,093.2**	3,555.3	(13)
NGL sales	**151.0**	243.3	(38)
Natural gas sales	**91.8**	88.9	3
Total oil and gas sales	**3,336.0**	3,887.5	(14)

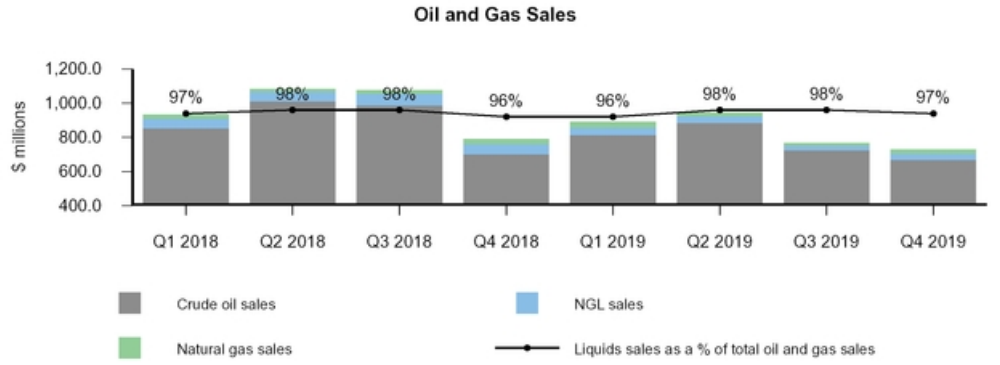
(1) Oil and gas sales are reported before realized derivatives .

Crude oil sales decreased 13 percent in 2019 primarily due to the 10 percent decrease in crude oil production from asset divestments and 3 percent decrease in realized crude oil prices.

NGL sales decreased 38 percent in 2019 primarily due to the 41 percent decrease in realized NGL prices, partially offset by the 5 percent increase in NGL production.

Natural gas sales increased 3 percent in 2019 primarily due to the 22 percent increase in realized natural gas prices, driven by the increase in the AECO daily benchmark price, partially offset by the 15 percent decrease in natural gas production.

Exhibit 7

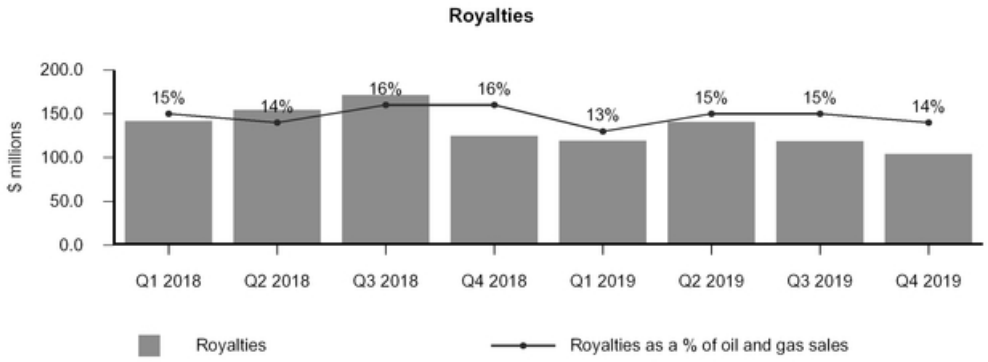


Royalties

($ millions, except % and per boe amounts)	**2019**	2018	% Change
Royalties	**482.8**	592.4	(19)
As a % of oil and gas sales	**14**	15	(1)
Per boe	**8.15**	9.11	(11)

Royalties decreased 19 percent in 2019 largely due to the 14 percent decrease in oil and gas sales. Royalties as a percentage of oil and gas sales remained relatively consistent with 2018. The one percent decrease in royalties as a percentage of oil and gas sales reflects the Uinta Basin disposition in the fourth quarter of 2019, which had higher associated royalty rates.

Exhibit 8



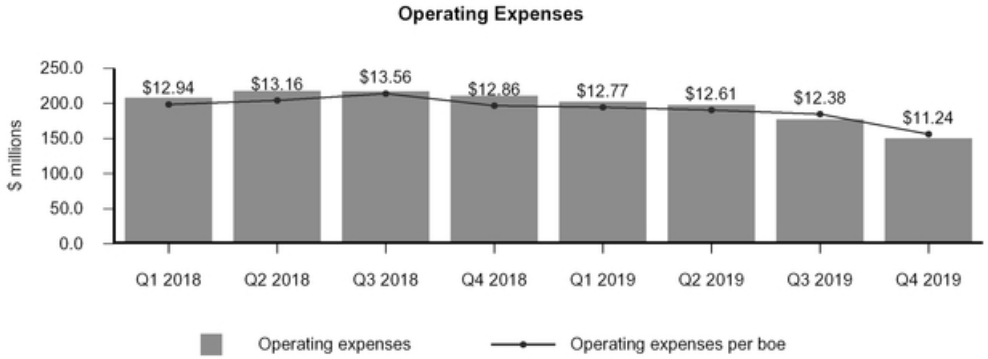
Operating Expenses

($ millions, except per boe amounts)	**2019**	2018 (1)	% Change
Operating expenses	**727.6**	853.8	(15)
Per boe	**12.29**	13.13	(6)

(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A for further information.

Operating expenses and operating expenses per boe decreased 15 percent and 6 percent, respectively, in 2019. The Company's increased focus on field efficiencies, cost control and an operations by exception platform has resulted in realized savings across its operations including labour and equipment repairs and maintenance. The decrease also reflects the Southeast Saskatchewan and Uinta Basin dispositions, which had higher average operating expenses.

Exhibit 9

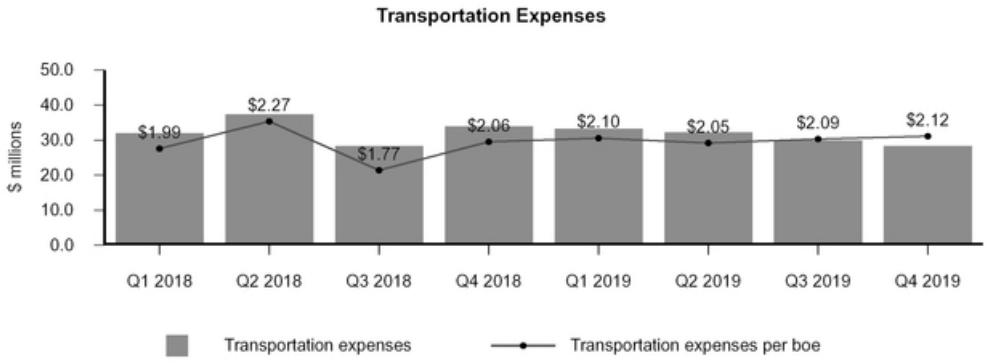


Transportation Expenses

($ millions, except per boe amounts)	**2019**	2018	% Change
Transportation expenses	**123.7**	131.7	(6)
Per boe	**2.09**	2.02	3

Transportation expenses decreased 6 percent in 2019 due to lower activity as a result of the reduction in production volumes from asset dispositions. Transportation expenses per boe increased 3 percent, primarily due to assets divestments that had lower associated transportation costs.

Exhibit 10



Netback

	2019	2018 [2]	
	Total [3] ($/boe)	Total [3] ($/boe)	% Change
Average selling price	**56.34**	59.78	(6)
Royalties	**(8.15)**	(9.11)	(11)
Operating expenses	**(12.29)**	(13.13)	(6)
Transportation expenses	**(2.09)**	(2.02)	3
Operating netback [1]	**33.81**	35.52	(5)
Realized gain (loss) on derivatives	**0.73**	(4.00)	(118)
Netback [1]	**34.54**	31.52	10

(1) Non-GAAP 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 *Non-GAAP Financial Measures* section in this MD&A for further information.

(2) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A for further information.

(3) The dominant production category for the Company's properties is crude oil. These properties 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, 2019 decreased 5 percent to $33.81 per boe from $35.52 per boe in 2018. The decrease in the Company's operating netback was primarily due to the decrease in average selling price, partially offset by lower royalties and operating expenses. The increase in the Company's netback was primarily the result of the realized gain on commodity derivatives compared to a realized loss in the same period in 2018, partially offset by the decrease in the operating netback.

Exhibit 11

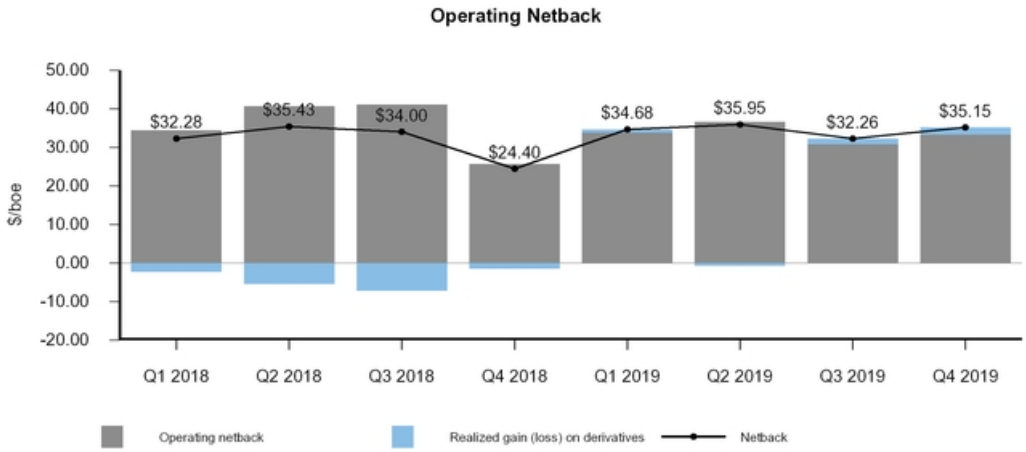
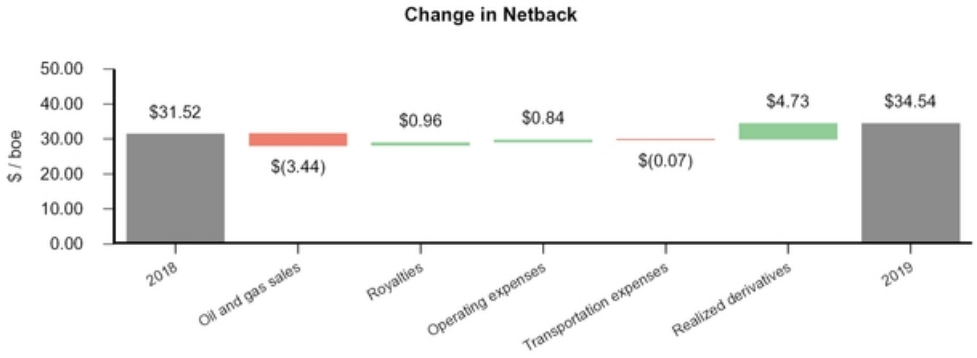


Exhibit 12



General and Administrative Expenses

($ millions, except per boe amounts)	**2019**	2018[1]	% Change
General and administrative costs	**127.6**	162.2	(21)
Capitalized	**(35.7)**	(40.3)	(11)
Total general and administrative expenses	**91.9**	121.9	(25)
Transaction costs	**(6.3)**	(5.1)	24
General and administrative expenses	**85.6**	116.8	(27)
Per boe	**1.45**	1.80	(19)

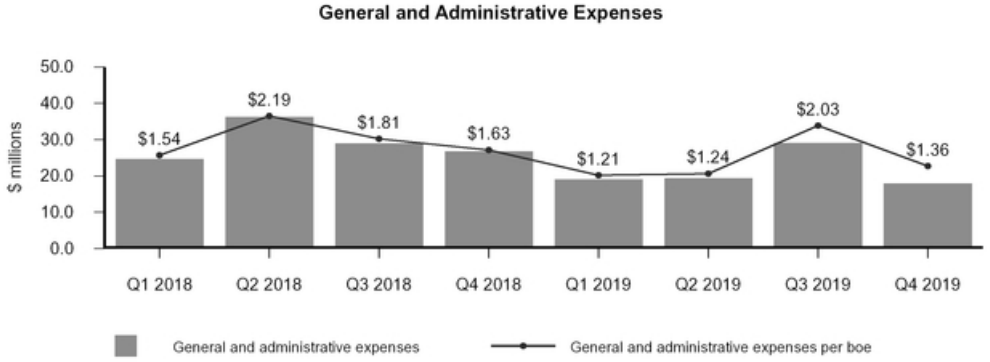
(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A.

General and administrative ("G&A") expenses decreased $31.2 million or 27 percent in 2019 primarily due to lower employee related costs, decreased shareholder costs and the reclassification of rent expense as a result of the adoption of IFRS 16, partially offset by lower overhead recoveries. In the year ended December 31, 2019, severance costs of $10.2 million were included in G&A, compared to $19.1 million in 2018. Severance costs in 2019 are related to workforce reductions as a result of asset divestments.

G&A expenses per boe decreased 19 percent in the year ended December 31, 2019 compared to 2018. The decrease is due to the decrease in total G&A as noted above, partially offset by lower production volumes.

Transaction costs incurred in the year ended December 31, 2019 relate primarily to the Uinta Basin and southeast Saskatchewan divestments. Refer to *Capital Acquisitions and Dispositions* section in this MD&A for further information.

Exhibit 13



Interest Expense

($ millions, except per boe amounts)	**2019**	2018[1] (Revised)	% Change
Realized			
Interest expense on long-term debt	**146.8**	184.4	(20)
Unrealized (gain) loss			
CCS - Interest	**23.6**	(20.7)	188
Interest expense	**170.4**	163.7	4
Per boe	**2.88**	2.52	14

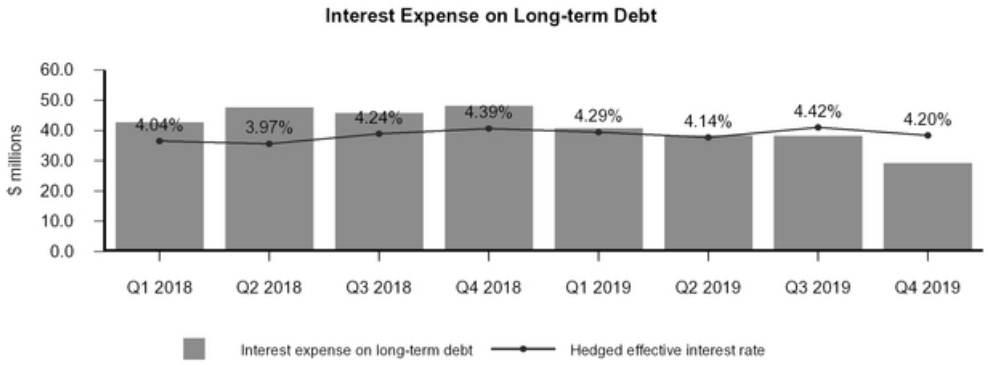
(1) Comparative period revised to reflect current period presentation. Unrealized derivative gain (loss) on interest rate contracts previously included in derivative gains (losses).

Interest expense on long-term debt decreased 20 percent in 2019 reflecting the Company's lower average debt balance. The Company's effective interest rate in 2019 increased to 4.26 percent from 4.16 percent in 2018.

The Company recorded a $23.6 million unrealized loss on interest rate derivatives in 2019 compared to a $20.7 million unrealized gain in 2018. The unrealized derivative loss in 2019 was primarily due to the impact of the stronger forward Canadian dollar at December 31, 2019 as compared to December 31, 2018 on the interest payments related to the Company's cross currency swaps ("CCS").

Crescent Point actively manages interest rate exposure through a combination of interest rate swaps and a debt portfolio including short-term floating rate bank debt and long-term fixed rate senior guaranteed notes. At December 31, 2019, 81 percent of the Company's long-term debt, including the impact of CCS and the foreign exchange swap on its US dollar senior guaranteed notes, had fixed interest rates.

Exhibit 14



Foreign Exchange Gain (Loss)

($ millions)	**2019**	2018 [1] (Revised)	% Change
Realized gain (loss)			
CCS - Principal	**32.4**	88.3	(63)
US dollar long-term debt maturities	**(32.4)**	(70.3)	(54)
Other	**(3.7)**	4.3	(186)
Unrealized gain (loss)			
CCS - Principal and foreign exchange swaps	**(141.6)**	215.3	(166)
Translation of US dollar long-term debt	**207.7**	(254.2)	(182)
Other	**(1.3)**	(2.1)	(38)
Foreign exchange gain (loss)	**61.1**	(18.7)	(427)

(1) Comparative period revised to reflect current period presentation. Unrealized derivative gain (loss) on CCS and foreign exchange swaps previously included in derivative gains (losses).

The Company has US dollar denominated debt, including London Inter-bank Offered Rate ("LIBOR") loans under its bank credit facilities and US dollar senior guaranteed notes. The Company hedges its foreign exchange exposure using a combination of CCS and foreign exchange swaps. During the year ended December 31, 2019, the Company had a realized loss on US dollar long-term debt maturities of $32.4 million, which was offset by the realized gain on CCS.

The Company records unrealized foreign exchange gains or losses on the period end translation of US dollar long-term debt and related accrued interest. The Company recorded an unrealized foreign exchange gain of $207.7 million on the translation of US dollar long-term debt and accrued interest in 2019 compared to an unrealized foreign exchange loss of $254.2 million in 2018. The unrealized foreign exchange gain from the translation of US dollar long-term debt and accrued interest in 2019 was attributable to a stronger Canadian dollar at December 31, 2019 as compared to December 31, 2018.

The Company recognized an unrealized derivative loss on CCS of $141.6 million for the year ended December 31, 2019 compared to an unrealized derivative gain of $215.3 million in 2018. The unrealized CCS derivative loss in 2019 was primarily the result of the stronger forward Canadian dollar at December 31, 2019 as compared to December 31, 2018.

Share-based Compensation Expense

($ millions, except per boe amounts)	**2019**	2018	% Change
Share-based compensation costs	**29.2**	53.7	(46)
Capitalized	**(4.3)**	(7.7)	(44)
Share-based compensation expense	**24.9**	46.0	(46)
Per boe	**0.42**	0.71	(41)

The Company recorded share-based compensation ("SBC") costs of $29.2 million in 2019, compared to $53.7 million in 2018. The 46 percent decrease in the year ended December 31, 2019 was primarily due to lower staffing levels in 2019 and the impact of the Company's share price. In addition, higher performance achievements associated with the Performance Share Unit ("PSU") Plan resulted in higher SBC costs in 2018, and the Company recorded SBC costs of $2.8 million related to an organizational restructuring during the year ended December 31, 2018.

Exhibit 15

The following table summarizes of the number of restricted shares, PSUs and Deferred Share Units ("DSUs") outstanding:

	December 31, 2019	December 31, 2018
Restricted Share Bonus Plan [1]	**3,636,194**	3,241,684
Performance Share Unit Plan [2]	**2,920,444**	2,246,314
Deferred Shared Unit Plan	**319,891**	301,614

(1) At December 31, 2019, the Company was authorized to issue up to 10,935,120 common shares (December 31, 2018 - 14,256,482 common shares)

(2) Based on underlying units before any effect of performance multipliers.

As of the date of this report, the Company had 3,107,399 restricted shares, 4,602,333 PSUs and 335,243 DSUs outstanding.

Stock Option Plan

The Company had 2,833,342 stock options outstanding at December 31, 2019 (December 31, 2018 - 2,048,115 stock options outstanding) at a weighted average exercise price of $7.59 per share.

As of the date of this report, the Company had 2,833,342 stock options outstanding.

Depletion, Depreciation, Amortization and Impairment

($ millions, except per boe amounts)	**2019**	2018 [1]	% Change
Depletion and depreciation	**1,117.8**	1,421.6	(21)
Amortization of exploration and evaluation undeveloped land	**129.1**	157.2	(18)
Depletion, depreciation and amortization	**1,246.9**	1,578.8	(21)
Impairment	**1,466.4**	3,705.9	(60)
Depletion, depreciation, amortization and impairment	**2,713.3**	5,284.7	(49)
Per boe, before impairment	**21.06**	24.28	(13)
Per boe	**45.82**	81.26	(44)

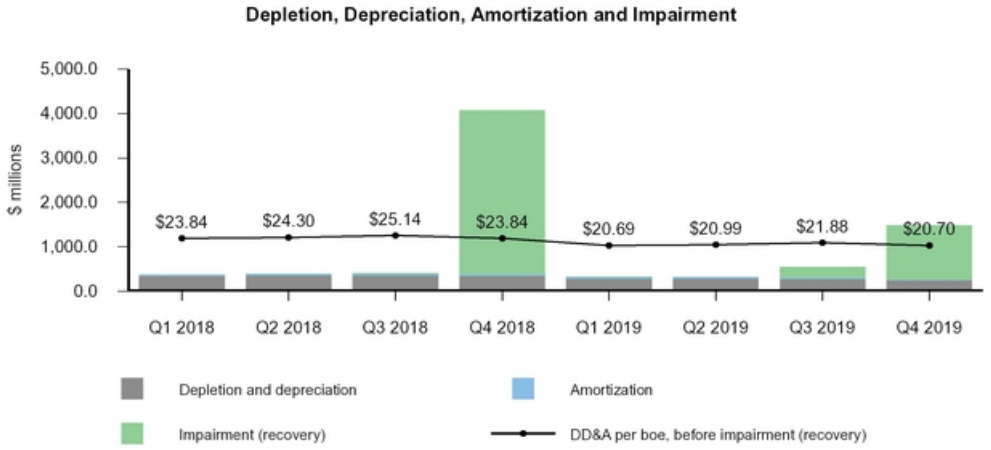
(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A for further information.

The Company's depletion, depreciation and amortization ("DD&A") rate before impairment for the year ended December 31, 2019 was $21.06 per boe compared to $24.28 per boe in 2018. The 13 percent decrease in the DD&A rate per boe in the year ended December 31, 2019 was primarily due to the impairment expense booked in the fourth quarter of 2018, which reduced the value of the Company's property, plant and equipment ("PP&E").

During the year ended December 31, 2019, the Company recorded impairment expense of $1.21 billion on its development and production assets primarily as a result of the decrease in forecast benchmark commodity prices. The value of the Company's assets was estimated based on independent evaluator pricing, proved plus probable reserves and a discount rate of 15 percent. The impairment charge does not impact the Company's adjusted funds flow, adjusted net earnings from operations or the amount of credit available under our bank credit facilities. The impairment can be reversed in future periods up to the original carrying value less any associated DD&A, should there be indicators that the value of the assets has increased.

The Company also recorded $258.6 million of impairment related to assets that were disposed in 2019, including the Company's Uinta Basin assets and other non-core assets.

Exhibit 16



Other Losses

The Company recorded other losses of $159.9 million in 2019 compared to $143.5 million in 2018. The losses in 2019 were comprised primarily of losses on asset dispositions, partially offset by proceeds received from a legal settlement and a gain recognized on lease modifications. The other losses in 2018 were comprised primarily of losses on asset dispositions and unrealized losses on long-term investments.

Taxes

($ millions)	**2019**	2018	% Change
Current tax expense	**0.4**	0.3	33
Deferred tax recovery	**(159.4)**	(938.8)	(83)

Current Tax Expense

In the year ended December 31, 2019, the Company recorded current tax expense of $0.4 million compared to a current tax expense of $0.3 million in 2018.

Deferred Tax Recovery

The Company recorded a deferred tax recovery of $159.4 million in 2019 compared to $938.8 million in 2018. The deferred tax recovery in 2019 primarily relates to the net loss before income tax and a change in estimate regarding future usable U.S. tax pools as a result of the Uinta Basin asset disposition.

The deferred tax recovery in 2018 was primarily the result of the net loss before income tax in 2018, which resulted mainly from the impairment expense recorded in the year.

Cash Flow from Operating Activities, Adjusted Funds Flow from Operations, Net Income (Loss) and Adjusted Net Earnings from Operations

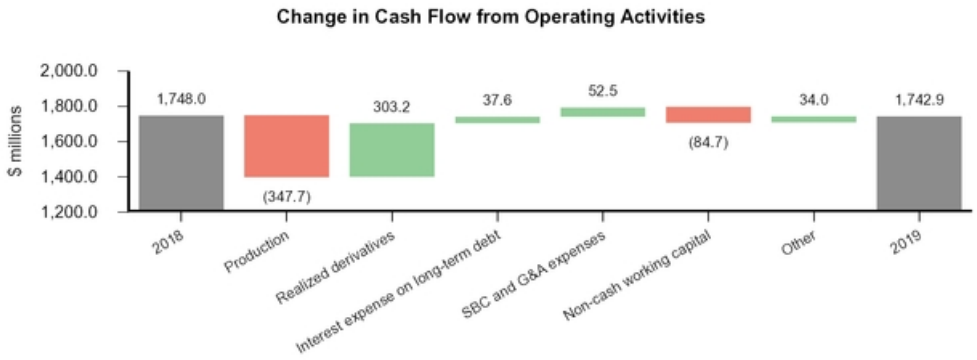
($ millions, except per share amounts)	**2019**	2018 [2]	% Change
Cash flow from operating activities	**1,742.9**	1,748.0	—
Adjusted funds flow from operations [1]	**1,825.4**	1,741.2	5
Net income (loss)	**(1,033.3)**	(2,616.9)	(61)
Net income (loss) per share - diluted	**(1.89)**	(4.77)	(60)
Adjusted net earnings from operations [1]	**386.8**	234.6	65
Adjusted net earnings from operations per share - diluted [1]	**0.71**	0.43	65

(1) Non-GAAP 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 *Non-GAAP Financial Measures* section in this MD&A for further information.

(2) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A.

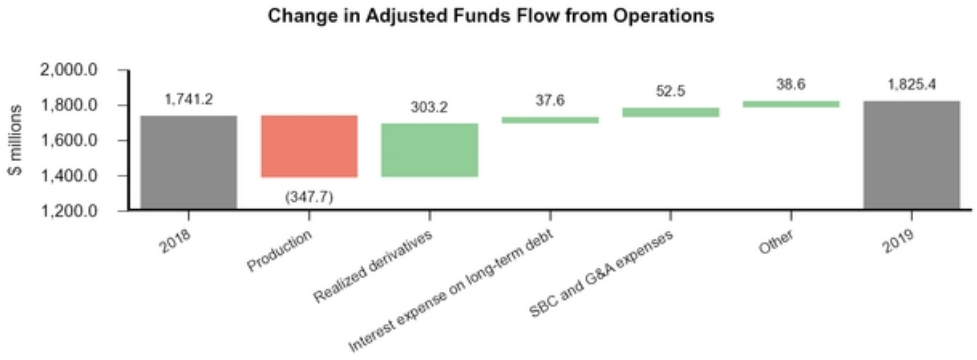
Cash flow from operating activities remained relatively consistent in the year ended December 31, 2019, compared to 2018.

Exhibit 17



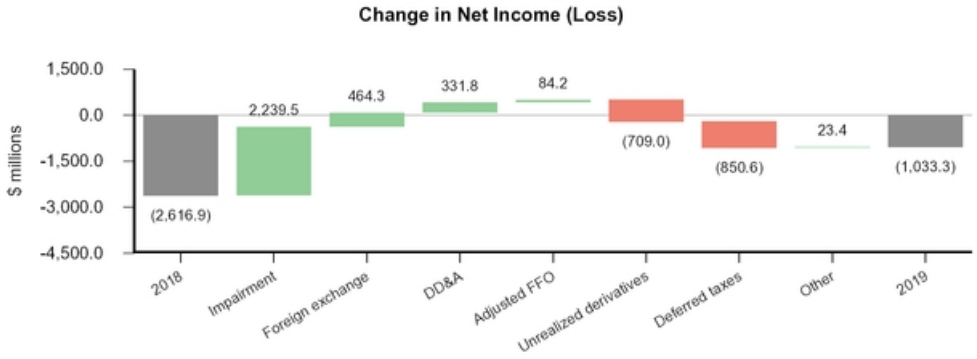
Adjusted funds flow from operations ("FFO") increased to $1.83 billion in the year ended December 31, 2019 from $1.74 billion in 2018. The increase is primarily the result of the realized derivative gain, a decrease in interest expense on long-term debt, and lower G&A expenses and cash-settled SBC costs, partially offset by the decrease in production volumes.

Exhibit 18



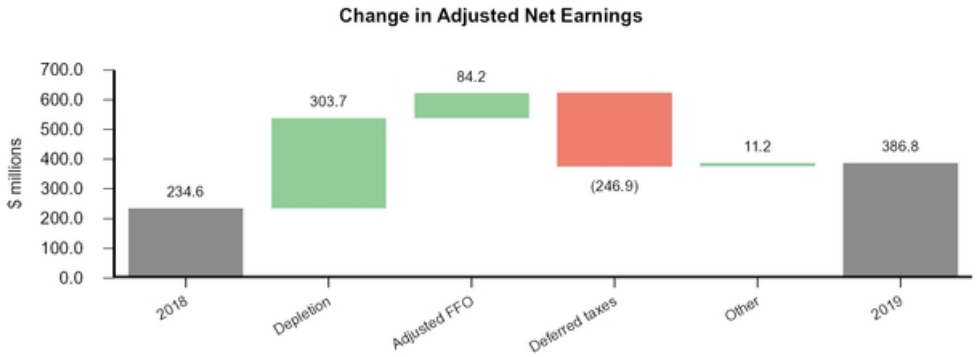
The Company reported a net loss of $1.03 billion in 2019, compared to $2.62 billion in 2018, primarily due to the decrease in impairment expense, the foreign exchange gain on long-term debt and the decrease in DD&A, partially offset by the unrealized derivative loss and fluctuations in deferred taxes. In 2019, the Company recorded net loss per share - diluted of $1.89 compared to net loss per share - diluted of $4.77 in 2018.

Exhibit 19



The Company reported adjusted net earnings from operations of $386.8 million in 2019 compared to $234.6 million in 2018, primarily due to the decrease in depletion and increase in adjusted FFO, partially offset by fluctuations in deferred taxes. Adjusted net earnings from operations per share - diluted increased 65 percent to $0.71 in 2019, compared to $0.43 in 2018.

Exhibit 20



Dividends

The following table provides a reconciliation of dividends:

($ millions, except per share amounts)	**2019**	2018	% Change
Accumulated dividends, beginning of year	**7,607.1**	7,408.6	3
Dividends declared to shareholders	**22.0**	198.5	(89)
Accumulated dividends, end of year	**7,629.1**	7,607.1	—
Accumulated dividends per share, beginning of year	**32.16**	31.80	1
Dividends declared to shareholders per share	**0.04**	0.36	(89)
Accumulated dividends per share, end of year	**32.20**	32.16	—

On January 15, 2019, the Company announced a change to the dividend policy to a quarterly cash dividend of $0.01 per share.

Other Long-Term Assets

At December 31, 2019, other long-term assets consist of $15.7 million of investment tax credits and $6.7 million of long-term investments.

Long-Term Investments

The Company holds common shares in publicly traded oil and gas companies, which were acquired through previous corporate acquisitions. The investments are recorded at fair value at each reporting period with the resulting gain or loss recorded in net income. At December 31, 2019, the investments were recorded at a fair value of $6.7 million, which was $0.6 million more than the original cost of the investments.

Related Party Transactions

Key management personnel of the Company include its directors and executive officers. In 2019, the Company recorded $5.8 million (2018 - $7.7 million) relating to compensation of key management personnel and $2.3 million (2018 - $11.3 million) for severance relating to key management personnel. In 2019, share-based compensation costs relating to compensation of key management personnel and severance were $10.3 million (2018 – $22.6 million) and nil (2018 - $2.8 million), respectively.

Capital Expenditures

($ millions)	**2019**	2018	% Change
Capital acquisitions	**15.9**	15.4	3
Capital dispositions	**(940.0)**	(355.9)	164
Development capital expenditures	**1,252.1**	1,736.6	(28)
Land expenditures	**15.5**	33.2	(53)
Capitalized administration [(1)]	**35.7**	40.3	(11)
Corporate assets	**2.9**	7.7	(62)
Total	**382.1**	1,477.3	(74)

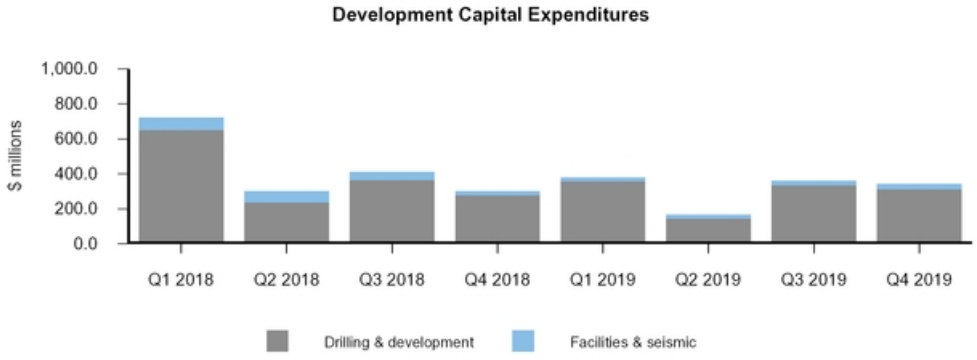
(1) Capitalized administration excludes capitalized equity-settled share-based compensation.

Development Capital Expenditures

The Company's development capital expenditures in the year ended December 31, 2019 were $1.25 billion, compared to $1.74 billion in 2018. In 2019, 510 (465.8 net) wells were drilled and $96.2 million was spent on facilities and seismic.

Crescent Point's budgeted capital expenditure guidance for 2020 is $1.10 billion to $1.20 billion, excluding any net land and property acquisitions.

Exhibit 21



Capital Acquisitions and Dispositions

Major Property Disposition

Uinta Basin Asset Disposition

On October 18, 2019, the Company sold its Uinta Basin assets, which included production of approximately 20,000 boe/d, for total consideration of $676.8 million after closing adjustments. Total consideration included cash of $653.9 million and working capital items of $22.9 million. These assets were classified as held for sale at September 30, 2019 resulting in an impairment charge of $241.4 million in the third quarter. A further impairment charge of $8.7 million was recorded upon closing of the transaction in the fourth quarter of 2019.

Southeast Saskatchewan Asset Disposition

In the third quarter of 2019, the Company sold certain southeast Saskatchewan conventional assets for total consideration of $196.9 million after closing adjustments. These non-core assets included production of approximately 7,000 boe/d. The Company recorded a loss on sale of $193.8 million in conjunction with the divestments.

Minor Property Acquisitions and Dispositions

In the year ended December 31, 2019, the Company completed minor property acquisitions and dispositions for total net consideration of $50.4 million, resulting in a loss on sale of $5.4 million.

Assets Held for Sale

In November 2019, the Company announced that it entered into a definitive agreement to sell certain gas infrastructure assets in Saskatchewan for cash consideration of $500.0 million. These assets have been classified as held for sale at December 31, 2019 at their carrying value of $187.1 million. The Company successfully closed the transaction on January 20, 2020.

Goodwill

The Company's goodwill balance is attributable to corporate acquisitions completed during the period 2003 through 2012. The goodwill balance as at December 31, 2019 was $230.9 million compared to $244.0 million at December 31, 2018. The decrease of $13.1 million is attributable to the southeast Saskatchewan conventional asset dispositions.

Other Current Liabilities

At December 31, 2019, other current liabilities consist of $2.3 million related to the current portion of long-term compensation liability, $31.3 million related to the current portion of lease liabilities, and $35.0 million related to decommissioning liability.

Other Long-Term Liabilities

At December 31, 2019, other long-term liabilities consist of $10.8 million of long-term compensation liability related to share-based compensation.

Lease Liability

At December 31, 2019, the Company had $181.2 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 $78.8 million during 2019 from $1.23 billion at December 31, 2018 to $1.15 billion at December 31, 2019. The liability was based on estimated undiscounted cash flows to settle the obligation of $1.09 billion.

Liquidity and Capital Resources

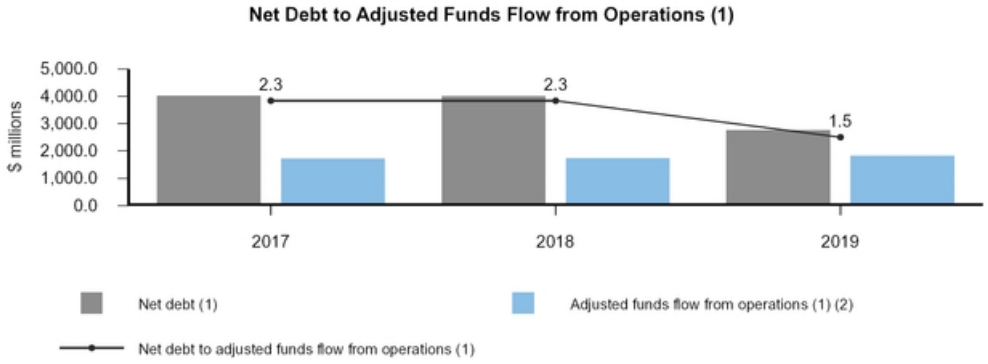
Capitalization Table ($ millions, except share, per share, ratio and percent amounts)	**December 31, 2019**	December 31, 2018
Net debt (1)	**2,765.3**	4,011.3
Shares outstanding	**529,399,923**	550,151,561
Market price at end of year (per share)	**5.79**	4.14
Market capitalization (1)	**3,065.2**	2,277.6
Enterprise value (1)	**5,830.5**	6,288.9
Net debt as a percentage of enterprise value	**47**	64
Adjusted funds flow from operations (1) (2)	**1,825.4**	1,741.2
Net debt to adjusted funds flow from operations (1)	**1.5**	2.3

(1) Non-GAAP 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 *Non-GAAP Financial Measures* section in this MD&A for further information.

(2) The sum of adjusted funds flow from operations for the trailing four quarters.

At December 31, 2019, Crescent Point's enterprise value was $5.83 billion and the Company was capitalized with 53 percent equity compared to $6.29 billion and 36 percent at December 31, 2018, respectively. The Company's net debt to adjusted funds flow from operations ratio at December 31, 2019 decreased to 1.5 times compared to 2.3 times at December 31, 2018, due to the reduction in net debt.

Exhibit 22



(1) Non-GAAP 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 *Non-GAAP Financial Measures* section in this MD&A for further information.

(2) The sum of adjusted funds flow from operations for the trailing four quarters.

The Company has combined facilities of $3.00 billion, including a $2.90 billion syndicated unsecured credit facility with fourteen banks and a $100.0 million unsecured operating credit facility with one Canadian chartered bank. The current maturity dates of the facilities is October 25, 2023. Both of these facilities constitute revolving credit facilities and are extendible annually. As at December 31, 2019, the Company had approximately $817.2 million drawn on bank credit facilities, including $6.5 million outstanding pursuant to letters of credit, leaving unutilized borrowing capacity of approximately $2.24 billion including cash of $56.9 million.

The Company has made private offerings of senior guaranteed notes raising total gross proceeds of US$1.41 billion and Cdn$270.0 million. 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 and foreign exchange swaps to hedge its foreign exchange exposure on its US dollar long-term debt.

The Company is in compliance with all debt covenants at December 31, 2019 which are listed in the table below:

Covenant Description	Maximum Ratio	**December 31, 2019**
Senior debt to adjusted EBITDA (1) (2)	3.5	**1.5**
Total debt to adjusted EBITDA (1) (3)	4.0	**1.5**
Senior debt to capital (2) (4)	0.55	**0.37**

(1) Adjusted EBITDA is calculated as earnings before interest, taxes, depletion, depreciation, amortization and impairment, 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 shareholder's equity and excludes the effect of unrealized derivative gains or losses and the adoption of IFRS 16.

The Company expects to finance its working capital deficiency and its ongoing working capital requirements through cash, adjusted funds flow from operations and its bank credit facilities.

Shareholders' Equity

At December 31, 2019, Crescent Point had 529.4 million common shares issued and outstanding compared to 550.2 million common shares at December 31, 2018. The decrease of 20.8 million shares is due to shares repurchased and cancelled under the NCIB, partially offset by shares issued pursuant to the Restricted Share Bonus Plan.

Normal Course Issuer Bid

On January 23, 2019, 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 38,424,678 common shares, or seven percent of the Company's public float, as at January 14, 2019. The NCIB commenced on January 25, 2019 and expired on January 24, 2020.

During 2019, the Company purchased and cancelled 24.1 million common shares for total consideration of $122.6 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.

As of the date of this report, the Company has purchased, for cancellation, 26.2 million common shares for total consideration of $135.3 million.

Outstanding Common Shares Data

As of the date of this report, the Company had 527,722,179 common shares outstanding.

Contractual Obligations and Commitments

The Company has assumed various contractual obligations and commitments in the normal course of operations. At December 31, 2019, 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)	5.6	9.7	11.7	37.9	64.9
Transportation	15.4	24.4	23.7	12.8	76.3
Capital	4.8	—	—	—	4.8
Total contractual commitments (2)	25.8	34.1	35.4	50.7	146.0

(1) Includes operating costs on the Company's office space, net of $14.3 million of recoveries from subleases.

(2) Excludes contracts accounted for under IFRS 16. See Note 13 - "Leases" in the annual consolidated financial statements for the year ended December 31, 2019 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]	234.6	532.3	829.2	500.5	2,096.6
Bank credit facilities [2]	39.9	916.8	—	—	956.7
Total contractual commitments	274.5	1,449.1	829.2	500.5	3,053.3

(1) These amounts include the notional principal and interest payments pursuant to the related CCS and foreign exchange swap, which fix the amounts due in Canadian dollars.

(2) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2019. The current maturity date of the Company's facilities is October 25, 2023. The Company expects that the facilities will be renewed and extended prior to their maturity dates.

Subsequent Events

Gas infrastructure assets disposition

On January 20, 2020, Crescent Point closed the sale of certain gas infrastructure assets in Saskatchewan for total cash consideration of $500.0 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, 2019. 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, 2019.

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 annual consolidated financial statements for the year ended December 31, 2019. The following discussion outlines what management believes to be 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 depletion, depreciation and amortization, decommissioning liability, deferred taxes, asset impairments 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 geoscientific interpretation, 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 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 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, the availability of cash flows 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; 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, rail 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; loss 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.

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: aboriginal 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.

Refer to the Company's Annual Information Form for the year ended December 31, 2019 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: employing qualified professional and technical staff; concentrating in a limited number of areas with low cost exploitation and development objectives; utilizing the latest 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 of commodity prices, interest and foreign exchange rates; adhering to conservative borrowing guidelines; monitoring counterparty creditworthiness and obtaining counterparty credit insurance.

Changes in Accounting Policies

On January 1, 2019, the Company adopted IFRS 16 using the modified retrospective approach. Under the modified retrospective approach comparative information has not been restated and continues to be reported under IAS 17 *Leases* and IFRIC 4 *Determining Whether an Arrangement Contains a Lease* The Company has applied the following practical expedients permitted under the standard. Some of these expedients are on a lease-by-lease basis and others are applicable by class of underlying assets.

- Account for leases with a remaining term of less than 12 months at January 1, 2019 as short-term leases;
- Account for lease payments as an expense and not recognize a right-of-use ("ROU") asset if the underlying asset is of a lower dollar value; and
- Use of the Company's previous assessment of impairment under IAS 37*Provisions, Contingent Liabilities and Contingent Assets*for onerous contracts instead of re-assessing the ROU asset for impairment on January 1, 2019.

The lease liability is calculated as the present value of the remaining lease payments, discounted using the Company's borrowing rate on January 1, 2019. The Company records financing expense on the lease liability and depreciation expense on the ROU asset and the associated ROU asset is measured as follows on a lease-by-lease basis:

- The amount equal to the lease liability on January 1, 2019 with no impact on retained earnings; or
- The balance on January 1, 2019 as if IFRS 16 had always been applied on the commencement of the lease, using the Company's borrowing rate on January 1, 2019 and with an impact on retained earnings calculated as the difference between the lease liability and the ROU asset values.

As a result of the adoption of IFRS 16, at December 31, 2019 net income (loss) before tax decreased $4.8 million and cash flow from operating activities increased $34.1 million. Refer to Note 4 - "Changes in Accounting Policies" in the audited consolidated financial statements for the year ended December 31, 2019 for additional information on the Company's adoption of IFRS 16.

Selected Annual Information

($ millions, except per share amounts)	**2019**	2018	2017
Oil and gas sales	**3,336.0**	3,887.5	3,303.9
Average daily production			
Crude oil (bbls/d)	**126,219**	140,298	139,996
NGLs (bbls/d)	**20,746**	19,805	18,250
Natural gas (mcf/d)	**91,592**	108,376	106,599
Total (boe/d)	**162,230**	178,166	176,013
Net income (loss) (1) (2)	**(1,033.3)**	(2,616.9)	(124.0)
Net income (loss) per share (1) (2)	**(1.89)**	(4.77)	(0.23)
Net income (loss) per share - diluted (1) (2)	**(1.89)**	(4.77)	(0.23)
Adjusted net earnings from operations (1) (3)	**386.8**	234.6	100.0
Adjusted net earnings from operations per share (1) (3)	**0.71**	0.43	0.18
Adjusted net earnings from operations per share – diluted (1) (3)	**0.71**	0.43	0.18
Cash flow from operating activities (1)	**1,742.9**	1,748.0	1,718.7
Adjusted funds flow from operations (1) (3)	**1,825.4**	1,741.2	1,728.8
Adjusted working capital (deficiency) (3) (4)	**(126.1)**	(208.2)	(133.3)
Total assets (1)	**10,091.8**	12,730.4	16,005.3
Total liabilities (1)	**4,749.1**	6,117.6	6,842.4
Net debt (3)	**2,765.3**	4,011.3	4,024.9
Total long-term derivative liability	**—**	—	16.6
Weighted average shares - diluted (millions)	**546.0**	550.2	546.8
Capital acquisitions	**15.9**	15.4	308.1
Capital dispositions	**(940.0)**	(355.9)	(306.3)
Development capital expenditures	**1,252.1**	1,736.6	1,625.0
Dividends declared	**22.0**	198.5	197.7
Dividends declared per share	**0.04**	0.36	0.36

(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies section* in this MD&A for further information.

(2) Net income (loss) and net income (loss) before discontinued operations are the same.

(3) Non-GAAP 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 *Non-GAAP Financial Measures* section in this MD&A for further information.

(4) Adjusted working capital deficiency is calculated as accounts payable and accrued liabilities and long-term compensation liability, less cash, accounts receivable, prepaids and deposits and long-term investments.

Crescent Point's oil and gas sales, cash flow from operating activities, adjusted funds flow from operations and total assets have fluctuated for the years 2017 through 2019, primarily due to changes in the Cdn $ WTI benchmark prices and corporate oil price differentials, numerous property acquisitions and dispositions and the Company's drilling program.

Net income over the past three years has fluctuated primarily due to unrealized derivative gains and losses on derivative contracts, which fluctuate with changes in market conditions, and net impairments to PP&E along with associated fluctuations in deferred tax expense (recovery).

Adjusted net earnings from operations has 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

	2019				2018			
($ millions, except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas sales	**729.3**	769.1	945.2	892.4	791.6	1,076.7	1,084.0	935.2
Average daily production								
Crude oil (bbls/d)	**111,394**	119,011	134,951	139,911	140,281	134,146	145,532	141,312
NGLs (bbls/d)	**21,406**	20,627	20,841	20,097	20,210	22,257	17,934	18,775
Natural gas (mcf/d)	**74,347**	96,422	100,101	95,679	106,236	107,231	110,110	109,983
Total (boe/d)	**145,191**	155,708	172,476	175,955	178,198	174,275	181,818	178,418
Net income (loss) [1]	**(932.1)**	(301.7)	198.6	1.9	(2,390.5)	30.5	(166.2)	(90.7)
Net income (loss) per share [1]	**(1.73)**	(0.55)	0.36	—	(4.35)	0.06	(0.30)	(0.17)
Net income (loss) per share – diluted [1]	**(1.73)**	(0.55)	0.36	—	(4.35)	0.06	(0.30)	(0.17)
Adjusted net earnings (loss) from operations [1] [2]	**49.9**	32.6	146.0	158.3	(16.3)	84.8	102.7	63.4
Adjusted net earnings (loss) from operations per share [1] [2]	**0.09**	0.06	0.27	0.29	(0.03)	0.15	0.19	0.12
Adjusted net earnings (loss) from operations per share – diluted [1] [2]	**0.09**	0.06	0.27	0.29	(0.03)	0.15	0.19	0.12
Cash flow from operating activities	**396.5**	402.2	527.4	416.8	359.1	474.1	452.8	462.0
Adjusted funds flow from operations [1] [2]	**418.4**	389.2	503.8	514.0	337.3	474.7	500.3	428.9
Adjusted working capital (deficiency) [3]	**(126.1)**	(100.2)	(124.7)	(139.8)	(208.2)	(139.9)	(90.4)	(339.8)
Total assets [1]	**10,091.8**	12,073.3	12,430.7	12,824.2	12,730.4	15,948.9	16,174.7	16,481.6
Total liabilities [1]	**4,749.1**	5,685.2	5,751.7	6,288.8	6,117.6	7,049.5	7,210.1	7,374.7
Net debt [2]	**2,765.3**	3,360.0	3,553.5	3,905.5	4,011.3	4,006.9	4,015.7	4,409.3
Total long-term derivative liability	**—**	—	—	5.9	—	17.9	35.3	17.4
Weighted average shares – diluted (millions)	**538.7**	548.0	548.2	550.3	550.2	551.1	551.0	548.4
Capital acquisitions	**13.5**	0.1	—	2.3	2.5	(1.8)	—	14.7
Capital dispositions	**(677.3)**	(199.3)	(58.3)	(5.1)	(45.0)	(19.6)	(267.6)	(23.7)
Development capital expenditures	**343.4**	362.3	166.2	380.2	302.3	411.1	301.2	722.0
Dividends declared	**5.4**	5.5	5.5	5.6	49.4	49.8	49.7	49.6
Dividends declared per share	**0.01**	0.01	0.01	0.01	0.09	0.09	0.09	0.09

(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies section* in this MD&A for further information.

(2) Non-GAAP 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 *Non-GAAP Financial Measures* section in this MD&A for further information.

(3) Adjusted working capital deficiency is calculated as accounts payable and accrued liabilities and long-term compensation liability, less cash, accounts receivable, prepaids and deposits and long-term investments.

Over the past eight quarters, the Company's oil and gas sales have fluctuated due to movement in the Cdn$ WTI benchmark price, changes in production and fluctuations in corporate oil price differentials. The Company's production has fluctuated due to its successful capital development program, dispositions and natural declines.

Net income has fluctuated primarily due to changes in adjusted funds flow from operations, unrealized derivative gains and losses, which fluctuate with the changes in forward market prices, impairments to PP&E recorded in the fourth quarter of 2019 and fourth quarter of 2018, and gains and losses on capital dispositions, along with associated fluctuations in deferred tax expense (recovery).

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 (recovery).

Capital expenditures fluctuated through this period as a result of timing of acquisitions, dispositions and the Company's capital development program. Cash flow from operating activities and adjusted funds flow from operations throughout the last eight quarters has allowed the Company to provide return to shareholders.

Fourth Quarter Review

- Crescent Point's production averaged 145,191 boe/d in the fourth quarter of 2019, a decrease of seven percent from third quarter 2019. Lower fourth quarter production was primarily a result of the Southeast Saskatchewan divestment that closed late in the third quarter and the Uinta Basin divestment that closed early in the fourth quarter. Production in the fourth quarter of 2019 was weighted 91 percent towards crude oil and liquids.

- Adjusted funds flow from operations totaled $418.4 million in the fourth quarter of 2019, an increase of seven percent from third quarter 2019 and adjusted net earnings totaled $49.9 million compared to $32.6 million in third quarter 2019. The increases in the fourth quarter were primarily driven by lower operating, general and administrative and interest expenses.

- The Company recognized an impairment charge of $1.21 billion due to lower forecast commodity prices.

- During the fourth quarter of 2019, the Company spent $312.7 million on drilling and development activities, drilling 137 (134.7 net) wells. Crescent Point also spent $30.7 million on facilities and seismic, for total development capital expenditures of $343.4 million.

- Net debt was reduced by $594.7 million in the fourth quarter of 2019, ending at $2.77 billion or 1.5 times trailing adjusted funds flow from operations.

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, 2019.

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, 2019, 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, 2019 based on the COSO Framework. Based on this evaluation, Management concluded that as of December 31, 2019, Crescent Point maintained effective ICFR.

The effectiveness of Crescent Point's ICFR as of December 31, 2019 was audited by PricewaterhouseCoopers LLP, as reflected in their report for 2019. There were no changes in Crescent Point's ICFR during the year ended December 31, 2019 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

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.

Outlook

Crescent Point's guidance for 2020 is as follows:

Production	
Total annual average production (boe/d)	140,000 - 144,000
% Oil and NGLs	91%
Development capital expenditures ($ millions) [(1) (2)]	$1,100 to $1,200
Drilling and development (%)	90%
Facilities and seismic (%)	10%

(1) The projection of development capital expenditures excludes property and land acquisitions, which are separately considered and evaluated.

(2) Based on US$55.00/bbl WTI, $0.75 US/CAD, MSW differential of ~US$7.00/bbl and WCS differential of ~US$19.00/bbl for 2020.

Crescent Point will continue to seek opportunities to further optimize its portfolio, while focusing on returns, capital discipline and cost saving initiatives to enhance value for shareholders.

Additional information relating to Crescent Point, including the Company's December 31, 2019 Annual Information Form, is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.shtml.

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses the terms “operating netback”, “netback”, “adjusted funds flow from operations”, “adjusted net earnings from operations”, “adjusted net earnings from operations per share”, “adjusted net earnings from operations per share - diluted”, “net debt”, “net debt to adjusted funds flow from operations”, “market capitalization” and “enterprise value”. 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.

Operating netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses. Netback is calculated on a per boe basis as operating netback plus realized derivative gains and losses. Operating netback and netback are common metrics used in the oil and gas industry and are used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis. The calculations of operating netback and netback are shown in the *Results of Operations* section in this MD&A.

Adjusted funds flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. 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. Management utilizes adjusted funds flow from operations as a key measure to assess the ability of the Company to finance dividends, 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.

The following table reconciles cash flow from operating activities to adjusted funds flow from operations:

($ millions)	**2019**	2018 [1]	% Change
Cash flow from operating activities	**1,742.9**	1,748.0	—
Changes in non-cash working capital	**47.5**	(37.2)	(228)
Transaction costs	**6.3**	5.1	24
Decommissioning expenditures	**28.7**	25.3	13
Adjusted funds flow from operations	**1,825.4**	1,741.2	5

(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A for further information.

Adjusted net earnings from operations is calculated based on net income before amortization of exploration and evaluation ("E&E") undeveloped land, impairment or impairment recoveries, 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 and gains or losses on capital acquisitions and dispositions. Adjusted net earnings from operations per share and adjusted net earnings from operations per share - diluted are calculated as adjusted net earnings from operations divided by the number of weighted average basic and diluted shares outstanding, respectively. Management utilizes adjusted net earnings from operations to present 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.

The following table reconciles net income to adjusted net earnings from operations:

($ millions)	**2019**	2018 [1]	% Change
Net income (loss)	**(1,033.3)**	(2,616.9)	(61)
Amortization of E&E undeveloped land	**129.1**	157.2	(18)
Impairment	**1,466.4**	3,705.9	(60)
Unrealized derivative (gains) losses	**269.6**	(439.4)	(161)
Unrealized foreign exchange (gain) loss on translation of hedged US dollar long-term debt	**(207.7)**	254.2	(182)
Unrealized loss on long-term investments	**2.0**	16.2	(88)
Gain on sale of long-term investments	**—**	(0.7)	(100)
Net loss on capital dispositions	**199.2**	129.1	54
Deferred tax relating to adjustments	**(438.5)**	(971.0)	(55)
Adjusted net earnings from operations	**386.8**	234.6	65

(1) On initial adoption of IFRS 16, the Company elected to use the modified retrospective approach; therefore, comparative information has not been restated. Refer to the *Changes in Accounting Policies* section in this MD&A for further information.

Net debt is calculated as long-term debt plus accounts payable and accrued liabilities and long-term compensation liability, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the unrealized foreign exchange on translation of US dollar long-term debt. Management utilizes net debt as a key measure to assess the liquidity of the Company.

The following table reconciles long-term debt to net debt:

($ millions)	**2019**	2018	% Change
Long-term debt [1]	**2,905.1**	4,276.7	(32)
Accounts payable and accrued liabilities	**479.4**	549.4	(13)
Long-term compensation liability [2]	**13.1**	10.0	31
Cash	**(56.9)**	(15.3)	272
Accounts receivable	**(295.9)**	(322.6)	(8)
Prepaids and deposits	**(6.9)**	(4.6)	50
Long-term investments	**(6.7)**	(8.7)	(23)
Excludes:			
Unrealized foreign exchange on translation of US dollar long-term debt	**(265.9)**	(473.6)	(44)
Net debt	**2,765.3**	4,011.3	(31)

(1) Includes current portion of long-term debt.

(2) Includes current portion of long-term compensation liability.

Net debt to adjusted funds flow from operations is calculated as the period end net debt divided by the sum of adjusted funds flow from operations for the trailing four quarters. The ratio of net debt to adjusted funds flow from operations is used by management to measure the Company's overall debt position and to measure the strength of the Company's balance sheet. Crescent Point monitors this ratio and uses this as a key measure in making decisions regarding financing, capital spending and dividend levels.

Market capitalization is calculated by applying the period end closing share trading price to the number of shares outstanding. Market capitalization is an indication of enterprise value. Refer to the *Liquidity and Capital Resources* section in this MD&A for further information.

Enterprise value is calculated as market capitalization plus net debt. Management uses enterprise value to assess the valuation of the Company. Refer to the *Liquidity and Capital Resources* section in this MD&A for further information.

Management believes the presentation of the Non-GAAP 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, has 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 report, 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 "Derivatives", “Liquidity and Capital Resources”, “Changes in Accounting Policies” and “Outlook”.

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, natural gas and power, fluctuations in the US/Cdn dollar exchange rate and interest rates movements through the use of derivatives with investment-grade counterparties;
- Crescent Point's use of financial commodity 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;
- Crescent Point’s 2020 average production and capital expenditure guidance;
- The Company seeking opportunities to further optimize its portfolio, while focusing on returns, capital discipline and cost saving initiatives to enhance value for shareholders;
- How the Company expects to finance its working capital deficiency and ongoing working capital requirements; and
- Estimated undiscounted cash flows to settle decommissioning liability.

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, rail blockades, outbreaks, blowouts; 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; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainty regarding the benefits and costs of dispositions; failure to complete 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; 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.

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 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.

Crude oil 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).

For the years ended December 31, 2019, 2018, 2017, 2016, and 2015 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. Therefore the difference between the reported numbers under the two disclosure standards can be material.

Directors

Barbara Munroe, Chair [6]

Laura Cillis [1] [2]

James Craddock [1] [3] [5]

John Dielwart [3] [4]

Ted Goldthorpe [1] [5]

Mike Jackson [1] [2] [5]

Jennifer Koury [2] [4]

Francois Langlois [3] [4] [5]

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 Environmental, Health & Safety 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

Brad Borggard
Senior Vice President, Corporate Planning and Capital Markets

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Garret Holt
Senior Vice President, Corporate Development

Head Office

Suite 2000, 585 - 8th Avenue S.W.
Calgary, Alberta T2P 1G1
Tel: (403) 693-0020
Fax: (403) 693-0070
Toll Free: (888) 693-0020

Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates 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

Brad Borggard
Senior Vice President, Corporate Planning and Capital Markets
(403) 693-0020

Shant Madian
Vice President, Investor Relations and Corporate Communications
(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 5, 2020

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(s) 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 5, 2020

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, 2019, 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 5, 2020

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, 2019, 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 5, 2020

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, 2019 of Crescent Point Energy Corp. of our report dated March 4, 2020, 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 S-8 (File No. 333-226210) and Form F-3D (File No. 333-205592) of Crescent Point Energy Corp. of our report dated March 4, 2020 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.

/s/ PricewaterhouseCoopers LLP
Calgary, Alberta

March 4, 2020

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

March 4, 2020

We refer to our report dated February 14, 2020 and effective December 31, 2019, evaluating the petroleum and natural gas reserves attributable to Crescent Point Energy Corp. (the "Company") and its affiliates, which is entitled "Reserves Assessment and Evaluation of Canadian and American Oil and Gas Properties (the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2019 dated March 4, 2020, 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.

Yours truly,

GLJ Petroleum Consultants Ltd.

/s/ Todd J. Ikeda
Todd J. Ikeda, P. Eng
Vice President

Exhibit 99.10

CONSENT OF INDEPENDENT ENGINEERS

March 4, 2020

We refer to our report dated January 21, 2020 and effective December 31, 2019, evaluating the petroleum and natural gas reserves attributable to Crescent Point Energy Corp. (the "Company") and its affiliates, which is entitled "Evaluation of Certain Saskatchewan P&NG Reserves of Crescent Point Energy Corp." (the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2019 dated March 4, 2020, 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.

Yours truly,

Sproule Associates Limited

/s/ Douglas O. McNichol
Douglas O. McNichol, P.Eng.
Senior Manager, Engineering

Crescent Point Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil & Gas (unaudited)
December 31, 2019

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, 2019 and 2018, 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

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.

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 subject to uncertainty 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.

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, 2019 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, 2017	327,724	47,438	229,274	413,375	47,860	5,588	75,973	66,110	375,583	53,027	305,248	479,485
Revisions of previous estimates	22,518	7,972	20,503	33,907	25,625	6,170	(12,056)	29,785	48,143	14,141	8,447	63,693
Improved recovery	6,854	1,972	6,933	9,981	—	—	—	—	6,854	1,972	6,933	9,981
Purchases of reserves in place	398	15	94	429	123	15	125	159	521	30	219	587
Extensions and discoveries	8,301	343	5,023	9,481	9,270	569	5,645	10,780	17,572	912	10,668	20,262
Production	(34,731)	(5,735)	(30,964)	(45,627)	(8,416)	(809)	(7,108)	(10,410)	(43,146)	(6,545)	(38,072)	(56,036)
Sales of reserves in place	(11,409)	(1,186)	(8,700)	(14,046)	(2,085)	(342)	(1,806)	(2,728)	(13,494)	(1,528)	(10,506)	(16,773)
December 31, 2018	319,655	50,819	222,164	407,502	72,378	11,190	60,774	93,697	392,033	62,009	282,938	501,198
Revisions of previous estimates	(20,438)	(4,954)	(23,260)	(29,269)	9,121	2,490	11,566	13,539	(11,318)	(2,464)	(11,695)	(15,730)
Improved recovery	1,058	41	534	1,188	—	—	—	—	1,058	41	534	1,188
Purchases of reserves in place	2,077	(11)	(18)	2,063	979	184	574	1,259	3,056	174	556	3,322
Extensions and discoveries	2,534	174	2,167	3,070	—	—	—	—	2,534	174	2,167	3,070
Production	(31,586)	(5,533)	(24,551)	(41,211)	(7,544)	(1,267)	(7,974)	(10,140)	(39,131)	(6,799)	(32,525)	(51,351)
Sales of reserves in place	(25,034)	(1,997)	(18,311)	(30,083)	(29,668)	(2,802)	(33,566)	(38,064)	(54,702)	(4,799)	(51,876)	(68,147)
December 31, 2019	248,266	38,540	158,726	313,260	45,266	9,796	31,374	60,291	293,531	48,336	190,100	373,550
Net Proved Developed Reserves												
December 31, 2017	227,769	33,732	168,407	289,569	29,701	3,785	43,236	40,692	257,470	37,517	211,643	330,261
December 31, 2018	228,814	38,092	163,850	294,214	36,549	5,599	38,290	48,530	265,363	43,691	202,139	342,744
December 31, 2019	193,456	31,722	126,464	246,255	16,212	4,888	15,147	23,625	209,668	36,610	141,611	269,880
Net Proved Undeveloped Reserves												
December 31, 2017	99,955	13,706	60,867	123,805	18,158	1,803	32,737	25,418	118,113	15,509	93,605	149,223
December 31, 2018	90,841	12,727	58,314	113,287	35,829	5,591	22,484	45,167	126,670	18,318	80,798	158,454
December 31, 2019	54,810	6,818	32,262	67,004	29,053	4,908	16,226	36,666	83,863	11,726	48,488	103,670

(1) Numbers may not add due to rounding.

Revisions of previous estimates - 2018

In 2018, total proved reserves increased by approximately 14.4 MMboe in Canada, and 39.8 MMboe in the United States due to increases in constant pricing for crude oil, natural gas, and NGL constituents at December 31, 2018 compared to December 31, 2017. In Canada, the majority of the remaining revisions are due to infill drilling in the Company's core areas of Viewfield (8.6 MMboe), Flat Lake in southeast Saskatchewan (7.0 MMboe), and Shaunavon in southwest Saskatchewan (4.9 MMboe), with the remainder being attributed to non-core areas (4.5 MMboe). These revisions were offset by minor negative performance based technical revisions of 5.5 MMboe. In the United States, the Company realized 13.1 MMboe of infill drilling additions from ongoing development in North Dakota. These positive adjustments were offset with the removal of low priority vertical locations in the Uinta basin in Utah (17.4 MMboe).

Revisions of previous estimates - 2019

In 2019, total proved reserves decreased by approximately 7.9 MMboe in Canada, and 2.2 MMboe in the United States due to decreases in constant pricing for crude oil, natural gas, and NGL constituents at December 31, 2019 compared to December 31, 2018. In Canada, the Company added 14.4 MMboe of total proved reserves through infill drilling, this includes the major areas of Viewfield (2.4 MMboe) and Flat Lake (3.1 MMboe) in Southeast Saskatchewan, as well as Shaunavon (5.8 MMboe) in Southwest Saskatchewan, with the remainder attributed to non-core areas (3.1 MMboe). This was offset with 19.5 MMboe of booked locations being removed due to lower than previously forecasted capital deployment in recent years. The remaining 16.3 MMboe of negative technical revisions were primarily due to a reassessment of the resource basins, which resulted in recognition of performance deviations from early forecasts. In the United States, the majority of the remaining revisions are due to continued development within North Dakota (12.3 MMboe) through infill drilling with the remainder coming from positive technical revisions of 3.4 MMboe.

Improved Recovery

In 2018, items reflected in improved recovery are due to the Company's ongoing waterflood development in the Viewfield (5.6 MMboe), Flat Lake (1.0 MMboe), Shaunavon (2.0 MMboe), and non-core areas (1.4 MMboe).

Extensions and Discoveries

In 2018, in Canada, the Company realized 9.5 MMboe of extensions, most of which are attributed to the aforementioned core areas (3.3 MMboe), the expanding Duvernay asset (2.9 MMboe), and an inventory realignment of southeast Saskatchewan conventional locations (2.8 MMboe). The Company realized an additional 10.0 MMboe in the United States due to the continued success of step out horizontal drilling in the Uinta Basin, with the remaining 0.8 MMboe from North Dakota. There were no reserves attributed to discoveries in 2018.

Sale of Reserves in Place

In 2018, the Company divested various non-core areas within Canada and the United States.

In 2019, the Company realized several key dispositions in Canada and the United States including the entirety of the Uinta Basin within Utah, as well as conventional assets within Canada including the Pinto area in Flat Lake and the Tatagwa area within Weyburn.

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, GLJ Petroleum Consultants Ltd. and Sproule Associates Limited. 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	**2019**	**2018**
WTI at Cushing Oklahoma ($US/bbl)	55.73	65.55
Edmonton ($Cdn/bbl)	66.77	70.32
Exchange Rate ($US/$Cdn)	0.7521	0.7758
AECO/NIT Spot ($Cdn/MMBTU)	2.02	1.46
Henry Hub NYMEX ($US/MMBTU)	2.54	3.02

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, 2019 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Future cash inflows	16,632	3,029	19,661
Future production costs	(6,951)	(1,158)	(8,109)
Future development costs and asset retirement obligations [2]	(2,699)	(1,063)	(3,762)
Future income taxes [3]	—	(18)	(18)
Future net cash flows	6,982	790	7,772
Deduct: 10% annual discount factor for timing of future cash flows	(2,392)	(479)	(2,871)
Standardized measure of future net cash flows	4,590	311	4,901

(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, 2019, the Company's Canadian and United States tax pools in Canadian dollars were approximately $7.7 billion and $3.0 billion, respectively.

December 31, 2018 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Future cash inflows	22,194	5,645	27,839
Future production costs	(9,083)	(1,942)	(11,025)
Future development costs and asset retirement obligations [2]	(2,952)	(1,353)	(4,305)
Future income taxes [3]	(554)	(50)	(604)
Future net cash flows	9,604	2,300	11,904
Deduct: 10% annual discount factor for timing of future cash flows	(3,528)	(1,018)	(4,547)
Standardized measure of future net cash flows	6,076	1,282	7,357

(1) Numbers may not add due to rounding.

(2) Asset retirement obligations include the costs related to future undrilled proved locations for which there were assigned proved undeveloped reserves.

(3) At December 31, 2018, the Company's Canadian and United States tax pools in Canadian dollars were approximately $8.4 billion and $3.8 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, 2019 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	6,076	1,282	7,357
Sales, net of production costs and royalties	(1,611)	(391)	(2,002)
Net change in prices and royalties related to forecast production	(429)	(305)	(734)
Development costs incurred during the period	883	349	1,232
Changes in estimated future development costs	27	2	29
Extensions, discoveries and improved recovery, net of related costs	78	—	78
Technical reserve revisions [2]	(659)	226	(433)
Purchases of reserves in place	16	7	23
Sales of reserves in place	(393)	(588)	(981)
Accretion of discount [3]	454	52	507
Net change in income taxes	236	13	250
All other changes [4]	(90)	(337)	(426)
Balance, end of year	4,590	311	4,901

(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) Estimated as 10% of the beginning of period net present value, less dispositions.

(4) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, currency exchange rates, and actual prices received in 2019 versus forecast.

December 31, 2018 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	5,420	714	6,134
Sales, net of production costs and royalties	(1,847)	(467)	(2,314)
Net change in prices and royalties related to forecast production	1,092	535	1,627
Development costs incurred during the period	1,061	589	1,650
Changes in estimated future development costs	(1)	4	3
Extensions, discoveries and improved recovery, net of related costs	318	207	526
Technical reserve revisions [2]	302	(138)	164
Purchases of reserves in place	5	2	7
Sales of reserves in place	(181)	(25)	(207)
Accretion of discount [3]	546	72	618
Net change in income taxes	(198)	(10)	(208)
All other changes [4]	(441)	(201)	(643)
Balance, end of year	6,076	1,282	7,357

(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) Estimated as 10% of the beginning of period net present value.

(4) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, currency exchange rates, and actual prices received in 2018 versus forecast.

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2019 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	21,611	1,428	23,039
Unproved properties	1,514	334	1,848
Total capital costs	23,125	1,762	24,887
Accumulated depletion, amortization and impairment	(16,051)	(803)	(16,854)
Net capitalized costs	7,074	959	8,033

As at December 31, 2018 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	22,331	4,304	26,635
Unproved properties	1,572	753	2,325
Total capital costs	23,903	5,057	28,960
Accumulated depletion, amortization and impairment	(15,057)	(3,057)	(18,114)
Net capitalized costs	8,846	2,000	10,846

Costs Incurred in Petroleum and Natural Gas Property Acquisitions, Exploration and Development Activities

Year ended December 31, 2019 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Property acquisition costs [2]			
Proved properties	1	9	10
Unproved properties	—	7	7
Development costs [3]	883	349	1,232
Exploration costs	16	19	35
Total	900	384	1,284

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $838.5 million and $101.9 million for proved and unproved properties, respectively.

(3) Costs incurred exclude capitalized administration.

Year ended December 31, 2018 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Property acquisition costs [2]			
Proved properties	6	7	13
Unproved properties	6	5	11
Development costs [3]	1,061	589	1,650
Exploration costs	32	88	120
Total	1,105	689	1,794

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $355.7 million and $7.5 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, 2019 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	2,304	550	2,854
Less:			
Operating expenses	579	149	728
Transportation expenses	114	10	124
Depletion, amortization and impairment	2,145	538	2,683
Accretion on decommissioning liability	22	2	24
Operating income (loss)	(556)	(149)	(705)
Income taxes	—	—	—
Results of operations	(556)	(149)	(705)

Year ended December 31, 2018 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	2,632	663	3,295
Less:			
Operating expenses	667	187	854
Transportation expenses	119	13	132
Depletion, amortization and impairment	3,950	1,325	5,275
Accretion on decommissioning liability	28	3	31
Operating income (loss)	(2,132)	(865)	(2,997)
Income taxes	—	—	—
Results of operations	(2,132)	(865)	(2,997)