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, 2018 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:	Name of each exchange on which registered:
Common Shares	**New York Stock Exchange**

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

None

(Title of Class)

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

None

(Title of Class)

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

☒ Annual Information Form ☒ Audited Annual Financial Statements

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

550,151,561 Common Shares (as at December 31, 2018).

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes ☐ 82-_____No ☒

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 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, 2018, 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, 2018, 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, 2018, 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, 2018, 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, 2018, 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, 2018, 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, 2018, 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, 2018, 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, 2018, 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 is an "audit committee financial expert" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee and is "independent" (as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers). For a description of Ms. L. Cillis's relevant experience in financial matters, see the biographical description for Ms. L. Cillis under "Directors and Officers" in the Registrant's Annual Information Form for the year ended December 31, 2018, which is filed as Exhibit 99.1 to this Annual Report on Form 40-F.

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 http://www.crescentpointenergy.com/responsible/governance/code-of-business-conduct-and-ethics

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, 2018, 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, 2018, 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 22 of the Registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2018, 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, 2018, 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. G. Romanzin, 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 http://www.crescentpointenergy.com/corporate-responsibility/governance. 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, 2018, 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 7, 2019

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, 2018.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2018 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, 2018.
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, 2018, 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, 2018

Dated March 6, 2019

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APPENDIX D - REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

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;
- expected director tenure and the timing and effectiveness of director appointments;
- forecast prices and the expected impact of commodity price fluctuations on cash available to pay dividends;
- our hedging strategy, including its expected outcomes, and our approval to managing physical delivery contracts;
- our risk mitigation strategy and the expected outcomes from same;
- the potential impact of competition and our working relationships with industry partners and joint operators on our 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;
- our leverage objectives for 2019;
- corporate and asset acquisitions and dispositions;
- drilling programs;
- expected location inventory development timing;
- the expected ongoing transition to horizontal wells in Utah and its anticipated impact on well bookings;
- our 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;
- our 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;
- our tax horizon;

- the impact of the Canada-United States-Mexico Agreement;
- expected trends in environmental regulation, including the anticipated impact the trends will have on our operations and our costs to comply;
- 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 ongoing normal course issuer bid;
- supply and demand for oil and natural gas;
- 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, 2018, under the headings "Risk Factors" and "Forward-Looking Information". The material assumptions and factors in making forward-looking statement are disclosed in the Management's Discussion and Analysis for the year ended December 31, 2018, 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; 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. 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. Therefore, 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 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 6, 2019 for the year ended December 31, 2018.

"**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, 2018.

"**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.

"**Shelter Bay**" means Shelter Bay Energy Inc.

"**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.

"**Tribe**" means the Ute Indian Tribe of the Uintah and Ouray Reservation.

"**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	barrel of oil equivalent of natural gas and crude oil on the basis of 1 boe for 6 (unless otherwise stated) Mcf of natural gas (this conversion factor is an industry accepted norm and is not based on either energy content or current prices)
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
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, 2018 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.

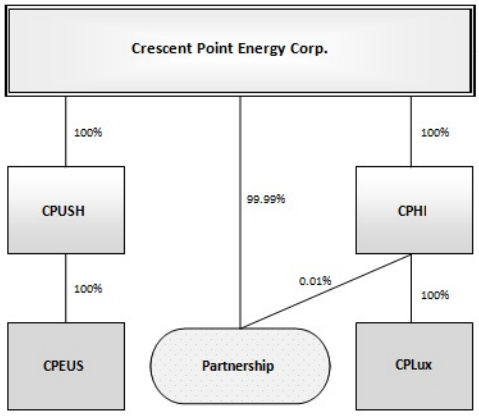
Relationships

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 intercorporate relationships among the Corporation and its material direct and indirect subsidiaries described above as at March 6, 2019. 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.

2016

On March 8, 2016, Barbara Munroe was appointed as a director of the Corporation. See " *Additional Information Respecting Crescent Point – Directors and Officers"*.

On March 8, 2016, the Corporation reduced its monthly dividend to $0.03 per share, effective with the March dividend payable on April 15, 2016.

On August 10, 2016, the terms of the Corporation's syndicated credit facility and operating credit facility were each extended to June 10, 2019 .

On September 20, 2016, the Corporation completed an equity offering of 33,700,000 Common Shares at a price of $19.30 per Common Share for aggregate gross proceeds of approximately $650 million.

In the third quarter of 2016, the Corporation completed a strategic core consolidation acquisition in its emerging-growth Flat Lake resource play and an acquisition of low-decline, conventional waterflood assets, both in southeast Saskatchewan. The Corporation also disposed of non-core assets in the Peace River Arch area of northwest Alberta for $31.0 million. Total net consideration for the acquisitions, net of the disposition was $211.7 million.

On November 9, 2016, Mike Jackson was appointed as a director of the Corporation. See " *Additional Information Respecting Crescent Point – Directors and Officers*".

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. The lands include 1,700 boe/d of production and provided the opportunity to expand the Corporation’s horizontal drilling expertise to an area with multi-zone potential.

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, of which approximately $20 million closed during the first quarter of 2018.

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 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*".

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, Montana and Utah. 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, 2018, we paid monthly dividends of $0.03 per Common Share. Commencing in 2019, we expect to pay a quarterly dividend of $0.01 per 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 American 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;

(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 2018 amounted to approximately 56% of annual production, net of royalties, consisting of approximately 58% of annual liquids production and approximately 32% of annual natural gas production, net of royalties. The Corporation recorded a realized derivative loss on crude oil and natural gas hedge contracts of $259.8 million in 2018.

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 2018, approximately 15,600 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, 2018.

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 three railcar loading facilities, serving its key producing areas of southeast Saskatchewan, southwest Saskatchewan and Utah. 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 or Utah, which diversifies 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 104 purchasers and its financial hedging portfolio consists of 16 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 U.S., Alberta, British Columbia, Manitoba and Saskatchewan. Approximately 71% of our liquids volumes are sold in Saskatchewan, 21% in the U.S., 7% in Alberta, 1% in Manitoba and less than 1% in British Columbia. Approximately 59% of our natural gas volumes are sold in Saskatchewan, 24% in the U.S., 17% in Alberta and less than 1% in British Columbia.

For 2018, our commodity production mix was approximately 90% crude oil and NGLs and 10% natural gas.

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

For Year Ended	Crude Oil and NGLs	Natural Gas
2018	98%	2%
2017	97%	3%
2016	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, 2018, the Corporation had 1,004 permanent employees: 416 employees at our head office in Calgary, 90 employees at our Denver office, 419 field employees in Canada and 79 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 by GLJ and Sproule with an effective date of December 31, 2018, and contained in the consolidated report of GLJ dated February 13, 2019 (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, 2018 forecast price and cost assumptions. GLJ evaluated approximately 45% of the assigned total Proved plus Probable reserves and 34% of the total Proved plus Probable value discounted at 10%. Sproule evaluated approximately 55% of the assigned total Proved plus

Probable reserves and 66% of the total Proved plus Probable value discounted at 10%. Sproule evaluated a majority of our southeast Saskatchewan assets including the Viewfield Bakken and Flat Lake Torquay properties in southeast Saskatchewan 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, British Columbia and Manitoba 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, as well as assets in the Uinta basin in Utah. 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 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 tax costs, and well and location abandonment costs for only those entities assigned reserves by GLJ and Sproule. 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 our operations. Crescent Point has estimated financial impacts based on current carbon pricing levels as adopted in existing and proposed legislation, and reflected these within the reserves evaluation as of December 31, 2018 as an operating cost per unit volume of production. No U.S. jurisdictions that we operate in have legislated or proposed costs associated with carbon, or greenhouse gases. The total impact of the carbon pricing in the Crescent Point Reserve Report reflects a negative impact of 940 Mboe and $161.7 MM discounted at 10% before tax for total proved plus probable reserves.

The Crescent Point Reserve Report is based on certain factual data supplied by us 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 our 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	91,754	81,711	24,625	20,295	137,025	127,961	42,290	39,023	115,594	109,379	71,226	66,717	326,831	298,339
United States	63	55	—	—	45,300	37,078	6,964	5,663	46,466	38,536	3	2	60,072	49,219
Total	91,817	81,766	24,625	20,295	182,326	165,038	49,254	44,686	162,060	147,915	71,229	66,719	386,903	347,558
Proved Developed Non-Producing														
Canada	1,784	1,625	2,619	2,293	4,439	4,133	1,075	990	3,243	3,025	1,151	928	10,649	9,700
United States	6	5	—	—	485	396	114	92	2,044	1,661	3	2	946	770
Total	1,789	1,629	2,619	2,293	4,925	4,529	1,189	1,082	5,287	4,686	1,154	930	11,595	10,470
Proved Undeveloped														
Canada	33,819	31,420	1,771	1,545	78,269	73,523	16,459	15,183	60,093	56,368	12,882	11,927	142,479	133,054
United States	—	—	—	—	59,828	48,770	8,898	7,225	59,076	48,184	—	—	78,572	64,025
Total	33,819	31,420	1,771	1,545	138,096	122,293	25,357	22,408	119,169	104,552	12,882	11,927	221,051	197,079
Total Proved														
Canada	127,356	114,756	29,015	24,133	219,734	205,617	59,824	55,196	178,930	168,773	85,259	79,572	479,960	441,093
United States	68	59	—	—	105,613	86,244	15,976	12,980	107,585	88,381	5	4	139,589	114,014
Total	127,424	114,815	29,015	24,133	325,347	291,861	75,800	68,176	286,515	257,154	85,264	79,576	619,549	555,107
Total Probable														
Canada	71,928	64,927	7,903	6,370	130,667	120,978	31,789	29,361	105,297	98,488	39,953	36,978	266,495	244,213
United States	31	27	—	—	78,820	64,376	10,513	8,544	73,380	60,060	2	2	101,594	82,957
Total	71,959	64,954	7,903	6,370	209,486	185,354	42,302	37,904	178,677	158,549	39,955	36,980	368,089	327,169
Total Proved Plus Probable														
Canada	199,284	179,683	36,918	30,502	350,400	326,595	91,613	84,556	284,228	267,261	125,212	116,550	746,455	685,305
United States	99	86	—	—	184,433	150,619	26,489	21,524	180,965	148,441	8	6	241,183	196,971
Total	199,383	179,769	36,918	30,502	534,833	477,215	118,102	106,080	465,193	415,702	125,219	116,557	987,638	882,276

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	11,993	8,873	7,701	7,090	5,947	5,152	10,994	8,300	7,274	6,734	5,713	4,992
United States	1,925	1,520	1,356	1,267	1,098	976	1,893	1,500	1,340	1,254	1,088	969
Total	13,918	10,392	9,057	8,358	7,044	6,128	12,887	9,800	8,615	7,989	6,801	5,961
Proved Developed Non-Producing												
Canada	444	304	257	234	191	162	324	227	195	179	150	131
United States	20	15	13	12	10	8	19	14	13	12	10	8
Total	463	319	270	246	201	170	343	241	208	191	160	139
Proved Undeveloped												
Canada	3,946	2,748	2,243	1,971	1,451	1,090	2,879	1,955	1,569	1,362	969	698
United States	1,566	860	606	479	257	119	1,440	799	564	446	237	107
Total	5,512	3,608	2,849	2,450	1,708	1,210	4,320	2,754	2,134	1,808	1,206	805
Total Proved												
Canada	16,383	11,924	10,202	9,295	7,589	6,404	14,197	10,482	9,039	8,276	6,832	5,821
United States	3,511	2,395	1,975	1,759	1,365	1,104	3,352	2,314	1,917	1,712	1,336	1,084
Total	19,894	14,319	12,177	11,053	8,953	7,508	17,550	12,796	10,956	9,988	8,167	6,905
Total Probable												
Canada	11,693	6,564	5,052	4,343	3,157	2,434	8,504	4,753	3,638	3,116	2,243	1,714
United States	3,696	1,949	1,435	1,199	814	590	2,781	1,500	1,123	949	663	491
Total	15,390	8,513	6,487	5,542	3,971	3,024	11,284	6,253	4,761	4,065	2,906	2,206
Total Proved Plus Probable												
Canada	28,076	18,488	15,253	13,638	10,745	8,838	22,701	15,235	12,677	11,392	9,075	7,535
United States	7,207	4,344	3,410	2,958	2,179	1,694	6,133	3,814	3,040	2,661	1,998	1,576
Total	35,283	22,832	18,663	16,596	12,925	10,532	28,834	19,049	15,718	14,053	11,073	9,111

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 (MM$)	Future Net Revenue Before Income Taxes (MM$)	Income Tax (MM$)	Future Net Revenue After Income Taxes (MM$)
Proved								
Canada	36,499	3,711	12,672	2,812	922	16,383	2,186	14,197
United States	10,690	2,557	2,876	1,635	111	3,511	158	3,352
Total	47,189	6,269	15,547	4,447	1,033	19,894	2,344	17,550
Proved Plus Probable								
Canada	59,885	6,052	20,093	4,513	1,151	28,076	5,375	22,701
United States	19,883	4,748	5,267	2,510	151	7,207	1,074	6,133
Total	79,768	10,801	25,359	7,023	1,302	35,283	6,450	28,834

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.

Future Net Revenue by Production Type (6)

	Future Net Revenue Before Income Taxes(5) (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved				
CANADA				
Light and Medium Crude Oil (1)	2,594	27.9	20.10	3.35
Heavy Crude Oil(1)	453	4.9	18.60	3.10
Tight Oil(3)	6,164	66.3	22.45	3.74
Natural Gas Liquids	—	—	—	—
Shale Gas (4)	—	—	—	—
Conventional Natural Gas (2)	84	0.9	6.40	1.07
Total Canada	9,295	100	21.07	3.51
UNITED STATES				
Light and Medium Crude Oil (1)	1	0.1	19.24	3.21
Heavy Crude Oil(1)	—	—	—	—
Tight Oil(3)	1,754	99.7	15.47	2.58
Natural Gas Liquids	—	—	—	—
Shale Gas (2)	3	0.2	5.79	0.96
Conventional Natural Gas (2)	—	—	—	—
Total United States	1,759	100	15.43	2.57
TOTAL				
Light and Medium Crude Oil (1)	2,595	23.5	20.10	3.35
Heavy Crude Oil(1)	453	4.1	18.60	3.10
Tight Oil(3)	7,918	71.6	20.41	3.40
Natural Gas Liquids	—	—	—	—
Shale Gas (2)(4)	3	—	5.79	0.96
Conventional Natural Gas (2)	84	0.8	6.40	1.07
Total Proved	11,053	100	19.91	3.32

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

	Future Net Revenue Before Income Taxes(5) (Discounted at 10% per year)	Percentage	Unit Value	
	(MM$)	*(%)*	*($/boe)*	*($/Mcfe)*
Proved Plus Probable				
CANADA				
Light and Medium Crude Oil(1)	3,885	28.5	18.88	3.15
Heavy Crude Oil(1)	545	4.0	17.73	2.96
Tight Oil(3)	9,115	66.8	21.04	3.51
Natural Gas Liquids	—	—	—	—
Shale Gas(4)	—	—	—	—
Conventional Natural Gas(2)	93	0.7	5.96	0.99
Total Canada	13,638	100	19.90	3.32
UNITED STATES				
Light and Medium Crude Oil(1)	2	0.1	17.94	2.99
Heavy Crude Oil(1)	—	—	—	—
Tight Oil(3)	2,952	99.8	15.05	2.51
Natural Gas Liquids	—	—	—	—
Shale Gas(2)	4	0.1	5.56	0.93
Conventional Natural Gas(2)	—	—	—	—
Total United States	2,958	100	15.02	2.50
TOTAL				
Light and Medium Crude Oil(1)	3,887	23.4	18.88	3.15
Heavy Crude Oil(1)	545	3.3	17.73	2.96
Tight Oil(3)	12,067	72.7	19.17	3.20
Natural Gas Liquids	—	—	—	—
Shale Gas(2)(4)	4	—	5.56	0.93
Conventional Natural Gas(2)	93	0.6	5.96	0.99
Total Proved Plus Probable	16,596	100	18.81	3.13

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

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, 2018 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										
2019	3.00	1.95	63.00	75.27	75.32	40.91	30.27	0.0%	0.0%	0.770
2020	3.25	2.44	67.00	77.89	80.00	50.25	34.51	2.0%	2.0%	0.800
2021	3.50	3.00	70.00	82.25	83.75	56.88	38.15	2.0%	2.0%	0.800
2022	3.57	3.21	71.40	84.79	85.50	58.01	39.64	2.0%	2.0%	0.800
2023	3.64	3.30	72.83	87.39	87.29	59.17	40.62	2.0%	2.0%	0.800
2024	3.71	3.39	74.28	89.14	89.11	60.36	41.62	2.0%	2.0%	0.800
2025	3.79	3.49	75.77	90.92	90.96	61.56	42.64	2.0%	2.0%	0.800
2026	3.86	3.58	77.29	92.74	92.86	62.79	43.68	2.0%	2.0%	0.800
2027	3.94	3.68	78.83	94.60	94.79	64.05	44.75	2.0%	2.0%	0.800
2028	4.02	3.78	80.41	96.49	96.76	65.33	45.83	2.0%	2.0%	0.800
2029	4.10	3.88	82.02	98.42	98.77	66.64	46.94	2.0%	2.0%	0.800
2030+	+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, 2018, the average realized sales prices before hedging were $69.17/bbl for light and medium crude oil, $57.30/bbl for heavy crude oil, $70.14/bbl for tight oil, $33.66/bbl for NGLs, $2.35/mcf for shale gas and $2.00/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, 2018 against such reserves as at December 31, 2017 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, 2017	142,531	79,797	222,328	26,335	7,237	33,571	222,676	129,610	352,286	55,361	29,298	84,659
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2)	14,731	8,858	23,590	1,613	710	2,323	24,335	15,552	39,887	5,027	3,452	8,479
Technical Revisions (4)	(832)	(7,796)	(8,628)	2,732	(37)	2,696	(4,001)	(14,374)	(18,375)	7,016	(103)	6,913
Acquisitions	22	51	73	—	—	—	499	62	561	9	1	10
Dispositions (6)	(16,587)	(9,738)	(26,325)	—	—	—	(296)	(567)	(863)	(1,377)	(936)	(2,313)
Economic Factors	1,336	756	2,093	115	(7)	108	818	384	1,202	(24)	77	53
Production (8)	(13,846)	—	(13,846)	(1,780)	—	(1,780)	(24,298)	—	(24,298)	(6,189)	—	(6,189)
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

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, 2017	169,468	87,940	257,408	110,844	54,593	165,437	493,621	269,698	763,318
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2)	19,376	19,280	38,657	3,810	2,437	6,247	49,570	32,192	81,762
Technical Revisions (4)	9,551	(2,127)	7,424	2,945	(2,754)	191	6,999	(23,123)	(16,124)
Acquisitions	285	34	319	—	—	—	577	120	697
Dispositions (6)	—	—	—	(16,725)	(12,754)	(29,479)	(21,047)	(13,367)	(34,414)
Economic Factors	416	170	586	(5,793)	(1,569)	(7,362)	1,349	976	2,326
Production (8)	(20,166)	—	(20,166)	(9,823)	—	(9,823)	(51,110)	—	(51,110)
December 31, 2018	178,930	105,297	284,228	85,259	39,953	125,212	479,960	266,495	746,455

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, 2017	1,049	4,382	5,431	—	—	—	101,023	74,641	175,664	13,729	9,741	23,470
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (3)	—	—	—	—	—	—	24,561	16,816	41,377	3,034	1,534	4,569
Technical Revisions (5)	125	28	153	—	—	—	(5,292)	(11,855)	(17,147)	937	(548)	390
Acquisitions	—	—	—	—	—	—	97	44	141	4	1	6
Dispositions (7)	(792)	(4,342)	(5,134)	—	—	—	(2,743)	(936)	(3,679)	(557)	(186)	(743)
Economic Factors	(18)	(38)	(56)	—	—	—	(1,041)	109	(933)	(132)	(30)	(162)
Production (8)	(296)	—	(296)	—	—	—	(10,990)	—	(10,990)	(1,040)	—	(1,040)
December 31, 2018	68	31	99	—	—	—	105,613	78,820	184,433	15,976	10,513	26,489

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, 2017	130,791	87,083	217,873	296	102	397	137,649	103,295	240,944
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (3)	14,182	11,957	26,139	—	—	—	29,959	20,343	50,302
Technical Revisions (5)	(23,100)	(25,516)	(48,616)	1,511	(136)	1,376	(7,827)	(16,650)	(24,478)
Acquisitions	178	89	267	—	—	—	131	61	192
Dispositions (7)	(3,147)	(1,025)	(4,172)	—	—	—	(4,617)	(5,634)	(10,251)
Economic Factors	(3,420)	792	(2,628)	(131)	36	(96)	(1,784)	179	(1,605)
Production (8)	(7,899)	—	(7,899)	(1,670)	—	(1,670)	(13,921)	—	(13,921)
December 31, 2018	107,585	73,380	180,965	5	2	8	139,589	101,594	241,183

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, 2017	143,580	84,179	227,759	26,335	7,237	33,571	323,698	204,252	527,950	69,090	39,039	108,129
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2) (3)	14,731	8,858	23,590	1,613	710	2,323	48,896	32,368	81,264	8,061	4,986	13,047
Technical Revisions (4) (5)	(707)	(7,768)	(8,474)	2,732	(37)	2,696	(9,293)	(26,229)	(35,522)	7,954	(651)	7,303
Acquisitions	22	51	73	—	—	—	596	107	702	13	3	16
Dispositions (6) (7)	(17,379)	(14,080)	(31,459)	—	—	—	(3,039)	(1,503)	(4,542)	(1,934)	(1,122)	(3,056)
Economic Factors	1,318	718	2,036	115	(7)	108	(223)	492	269	(156)	47	(109)
Production (8)	(14,141)	—	(14,141)	(1,780)	—	(1,780)	(35,288)	—	(35,288)	(7,229)	—	(7,229)
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

TOTAL	Shale Gas (5) (Natural Gas) *(MMcf)*			Conventional Natural Gas (5) (Natural Gas) *(MMcf)*			Total BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
December 31, 2017	300,259	175,023	475,281	111,140	54,695	165,834	631,270	372,993	1,004,262
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery (2) (3)	33,558	31,237	64,795	3,810	2,437	6,247	79,529	52,535	132,064
Technical Revisions (4) (5)	(13,549)	(27,643)	(41,192)	4,456	(2,889)	1,567	(829)	(39,773)	(40,602)
Acquisitions	463	122	586	—	—	—	708	180	889
Dispositions (6) (7)	(3,147)	(1,025)	(4,172)	(16,725)	(12,754)	(29,479)	(25,664)	(19,001)	(44,665)
Economic Factors	(3,004)	962	(2,042)	(5,924)	(1,534)	(7,458)	(434)	1,155	721
Production (8)	(28,064)	—	(28,064)	(11,493)	—	(11,493)	(65,031)	—	(65,031)
December 31, 2018	286,515	178,677	465,193	85,264	39,955	125,219	619,549	368,089	987,638

Notes:
(1) Numbers may not add due to rounding.
(2) The Corporation's Canadian development strategy in 2018 included both step-out and in-fill development drilling, mostly in the Bakken and Torquay resource plays in southeast Saskatchewan; the Lower Shaunavon resource play in southwest Saskatchewan; and the emerging Duvernay resource play in Alberta. The Corporation also received 21.5 MMboe additional Total Proved plus Probable Improved Recovery bookings from the qualified reserve evaluators due to ongoing waterflood development activities.
(3) The Corporation's United States development strategy in 2018 included both step-out and in-fill development drilling, mostly in the Bakken and Three Forks resource plays in North Dakota; as well as a focus on horizontal well development in the Uinta basin resource play in Utah.
(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 Viewfield Bakken, Flat Lake Torquay and Shaunavon resource assets, representing a large portion of the revisions in this category. The net Total Proved plus Probable impact represented here is only 1.6% of the prior year Corporate Total Proved plus Probable reserves.
Negative Technical Revisions were observed in the Corporations conventional assets in southeast Saskatchewan due to a full reassessment of the location inventory, which resulted in removal of a number of prior booked locations, many of which were replaced by locations in adjacent lands reflected as Extensions and Improved Recovery.
(5) In Utah, the Corporation reduced its vertical location inventory by 111 (81.8 net) locations in Total Proved reserves for a total of 6.9 MMboe; and 294 (129.1 net) locations in Total Proved plus Probable reserves for a total of 14.2 MMboe. These locations were both economic and technically feasible, however, due to a low likelihood of development within five years, are more appropriate to be considered as Contingent Resources.
(6) Various Light and Medium Crude Oil assets in southeast Saskatchewan and Viking assets in Alberta were disposed during the year.
(7) Non-core assets operated and non-operated were disposed in North Dakota.
(8) The Corporation produced an average of 140,027 boe per day in Canada, 38,139 boe per day in the United States for a total of 178,166 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 may relate to planned infill drilling, lease-line as well as 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.

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 75% 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 focus areas of Southeast Saskatchewan, Southwest Saskatchewan and Utah regions.

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
2016	3,164	43,999	—	2,006	9,944	132,528	1,406	19,813	5,535	108,708	1,866	24,915	15,748	220,617
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

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 58% of the net undeveloped location count, as well as 56% 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 de-risking current Probable locations to Proved locations during the early years of development.

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
2016	5,993	62,440	—	1,813	21,649	111,208	2,804	16,710	10,751	78,493	1,457	37,182	32,481	211,449
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

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 year-end oil and gas 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	
Year	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable
2019	770	1,010	371	489	1,141	1,498
2020	780	1,097	406	558	1,186	1,655
2021	584	997	374	655	958	1,652
2022	455	790	255	504	711	1,293
2023	193	590	227	303	420	893
2024	8	2	1	—	9	2
2025	2	2	—	—	2	2
2026	1	2	—	1	1	3
2027	4	1	—	—	4	1
2028	1	5	—	—	1	5
2029	3	1	—	—	3	1
2030	1	3	—	—	1	3
Subtotal(1)	2,800	4,498	1,635	2,510	4,435	7,008
Remainder	12	15	—	—	12	15
Total(1)	2,812	4,513	1,635	2,510	4,447	7,023
10% Discounted	2,333	3,658	1,332	2,025	3,665	5,683

Notes:

(1) Numbers may not add due to rounding.

(2) In Canada, the Corporation drilled 661 (551.1 net) wells in 2018. For 2019, the Corporation has budgeted the drilling of 487 (431 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, both the total Proved and total Proved plus Probable drilling schedule occur within a five year period. All remaining capital expenditures beyond the five year period relate to maintenance capital on existing wells and assets. The timing of this maintenance capital may shift from Proved to 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 94 (54.4 net) wells in 2018, while in 2019, the Corporation is budgeting the drilling of 67 (34 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 over 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. The Corporation has no properties where reserves are assigned, but are non-producing. Unless otherwise noted, reserve amounts are stated before deduction of royalties, based on escalating cost and price assumptions as evaluated in the Crescent Point Reserve Report as at December 31, 2018.

Viewfield Bakken Resource

Crescent Point is the largest Canadian producer across the Viewfield Bakken resource area in southeastern Saskatchewan, with 2018 average production of 44,500 boe per day. The Corporation holds more than 900 net sections of Bakken rights in the Viewfield area. 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, or is in the final stages of unitization. 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 $204 million, representing approximately 12% of its 2018 capital development program, on the Viewfield Bakken resource area including drilling 112 (102.1 net) additional wells. The Corporation also continued to focus on waterflood development and facility enhancements during the year.

At year-end 2018, the Corporation's total Proved plus Probable reserves in the Viewfield Bakken area were 246.3 MMboe, with 719 (671.8 net) locations booked to these reserves. This represents 24.9% 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. In addition, the independent qualified reserve evaluators have recognized 11.5 MMboe of incremental waterflood recoveries in the Viewfield Bakken resource basin in the 2018 year-end total Proved plus Probable reserves assessment.

In 2019, Crescent Point plans for the Viewfield Bakken resource play include drilling approximately 115 (107 net) wells, 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 plays. Both zones are medium oil quality, and they jointly cover more than 600 sections of land. Crescent Point holds rights to a large portion of the lands bearing one or both of these zones, with 2018 production averaging approximately 27,300 boe per day. Most conventional portions of the Upper Shaunavon have been under development for several decades, originally using vertical wells, with both waterfloods and enhanced recovery techniques in place. The Corporation has been developing these reservoirs using fracture stimulated horizontal wells and by advancing waterflood development that have continued to grow production in the area.

In 2018, the Corporation continued to develop the Shaunavon area by drilling 125 (123.2 net) wells, and by applying improved technologies and waterflood optimization to enhance recoveries. Total capital spent on these activities was $216 million in 2018, representing approximately 12% of the Corporation's development capital budget.

As of year-end 2018, Crescent Point has booked total Proved plus Probable reserves of 147.6 MMboe in the Shaunavon area, representing approximately 15% of the total Proved plus Probable reserves. The Corporation has 646.4 (447.1 net) locations booked to total Proved plus Probable reserves as of year-end 2018. Crescent Point expects to fully develop this location inventory within five years, with the majority of the Total Proved locations being developed in four years. The Corporation's independent qualified reserve evaluators recognized an additional 3.0 MMboe of Proved plus Probable

reserves due to incremental waterflood recoveries across the basin in the 2018 year-end total Proved plus Probable reserves assessment.

In 2019, Crescent Point plans to drill approximately 95 (95 net) horizontal wells in the Shaunavon area. As well, the Corporation plans to continue to advance waterflood optimization in the Lower and Upper Shaunavon zones.

Flat Lake Area

The Flat Lake area is situated directly north of the U.S. border in southeastern Saskatchewan, with Crescent Point holding rights to more than 700 net sections of land. The Corporation is developing the tight Bakken, Torquay and Midale light oil resource plays, as well as the conventional Ratcliffe (Oungre) play, in each case with horizontal wells. Production in the area averaged 22,200 boe per day in 2018. The Corporation has been able to utilize best practices from the Viewfield Bakken, residing directly north of Flat Lake, as well as strategies utilized in North Dakota where the Torquay resource is equivalent to the U.S. Three Forks resource play, in the development of these assets, with a focus on implementation of waterfloods to improve recoveries.

The Corporation spent $367 million, representing 20.7% of its 2018 capital development program, mostly on the Torquay and Ratcliffe plays in Flat Lake including drilling 182 (174.1 net) wells, of which 100 (97.1 net) were Ratcliffe and 72 (71 net) were Torquay. The Corporation also continued to focus on waterflood development and facility enhancements during the year including 27 (27 net) conversions to water injection.

At year-end 2018, the Corporation's total Proved plus Probable reserves in the Flat Lake area were 103.6 MMboe, representing 10.5% of the Corporation’s total. Included in these reserve volume bookings were 465 (446.4 net) locations. It is expected the majority of these Total Proved as well as the Total Proved plus Probable locations will be developed in two years with all locations being developed within four years. In addition, the independent qualified reserve evaluators recognized 4.4 MMboe of incremental waterflood recoveries in the Flat Lake area in the 2018 year-end total Proved plus Probable reserves assessment.

For 2019 Crescent Point expects to drill approximately 111 (108 net) wells focused mostly in the Torquay and Ratcliffe plays in the Flat Lake area. As in prior years, this program is designed to expand and diversify our asset base, expand waterflood development and develop our drilling inventory.

Uinta Basin

The Uinta Basin resource play sits in northeast Utah. It is a thick, multi-zone, large oil-in-place light oil resource play that has, to a large extent, been developed using vertical multi-fracture stimulated wells. Crescent Point is continuing the horizontal development of the resource using both one-mile and two-mile horizontal wells, primarily focused on the Castle Peak, Uteland Butte and Wasatch zones within this expansive reservoir package.

In 2018, Crescent Point spent $355 million of its capital budget in the area, including drilling 49 (22.4 net) wells, that focused mostly on horizontal development, representing 20.1% of the capital budget.

Total Proved plus Probable reserves in the Uinta Basin were 125.8 MMboe at year-end 2018 including 555 (340.2 net) Proved plus Probable booked locations. Of these locations, 143 (84.7 net) are horizontal locations. With the continued early success of horizontal wells in the Uinta Basin, Crescent Point is reviewing its inventory of vertical locations in order to determine an optimal development strategy, either vertically or horizontally. Reserves in the Uinta Basin represent 12.7% of the Corporation’s total Proved plus Probable reserve bookings as of December 31, 2018. Crescent Point expects to fully develop its current location inventory within five years.

For 2019, Crescent Point expects to drill approximately 41 (12 net) wells. The Corporation also plans to expand infrastructure including salt water disposal facilities and water gathering systems.

North Dakota

The Bakken and Torquay resource plays in southeastern Saskatchewan extend into North Dakota where the Torquay resource is equivalent to the United States Three Forks resource play. Crescent Point is able to utilize its expertise from developing the Viewfield Bakken and Flat Lake Torquay plays, to optimize development of its North Dakota resources and

vice versa. Production is a high quality light oil and is developed using multi-fractured horizontal wells, with 2018 average working interest production rates of approximately 15,400 boe per day.

In North Dakota, the Corporation spent $320 million representing 18.1% of its 2018 capital development program, drilling 49 (33.7 net) horizontal wells.

At year-end 2018, the Corporation's Total Proved plus Probable reserves in North Dakota were 115.3 MMboe, with 201 (149.0 net) locations booked, representing 11.7% 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.

In 2019, Crescent Point expects to drill approximately 26 (23 net) wells in North Dakota.

Oil and Gas Wells

Producing Wells				
Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	9,738	8,246	291	54
Alberta	688	562	319	232
Manitoba	153	137	—	—
British Columbia	9	6	—	—
TOTAL CANADA	10,588	8,951	610	286
U.S.				
Utah	3,494	1,119	433	146
North Dakota	324	207	—	—
Montana	25	15	40	20
TOTAL U.S.	3,843	1,341	473	166
Total	14,431	10,292	1,083	452

Non-Producing Wells				
Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Saskatchewan	3,793	3,091	564	419
Alberta	260	169	191	151
Manitoba	—	—	—	—
British Columbia	—	—	4	2
TOTAL CANADA	4,053	3,260	759	572
U.S.				
Utah	493	153	32	18
North Dakota	27	24	—	—
Montana	12	7	7	4
TOTAL U.S.	532	184	39	22
Total	4,585	3,444	798	594

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 be 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. The Corporation utilizes a portion of its operating cash flows to fund current and future decommissioning costs on a priority based system. Non-producing reserves represent only 1.9% of both the Total Proved, as well as the Total Proved plus Probable reserve categories.

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, 2018		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
CANADA			
Alberta	829,103	774,616	229,470
Saskatchewan	1,184,092	1,122,390	450,522
Manitoba	9,720	9,384	8,217
British Columbia	30,610	18,429	—
Total	2,053,525	1,924,819	688,209
U.S.			
Montana	73,262	54,966	—
North Dakota	43,790	36,631	783
Utah	423,402	219,716	5,706
Total	540,454	311,313	6,489
Total	2,593,979	2,236,132	694,698

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, 2018, in each of Canada and the United States.

	Development Wells		Exploration Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	640	533	10	9	650	541
Natural Gas wells	—	—	—	—	—	—
Service wells	6	6	—	—	6	6
Stratigraphic test	—	—	—	—	—	—
Dry Holes (3)	1	1	—	—	1	1
Total (1)	647	539	10	9	657	548

	Development Wells		Exploration Wells (2)		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	85	51	13	7	98	58
Natural Gas wells	—	—	—	—	—	—
Service wells	—	—	—	—	—	—
Stratigraphic Test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total (1)	85	51	13	7	98	58

Notes:
(1) Numbers may not add due to rounding.
(2) Exploration wells in this grouping are based on Lahee classification at the time of drilling. Not all these wells were granted reserves in the Crescent Point Reserve Report. For the wells that were included in the Corporation's year end reserves, all were included in the "Extensions and Improved Recovery" category in the "Reconciliations of Changes in Reserves" table due to them being drilled in large resource based areas, that exhibit extensive reservoir characteristics, and hence are not considered true "Discoveries".
(3) Following an operational issue, the well was abandoned downhole. The well may be reentered and sidetracked in the future.

For details on important exploration and development activities during 2018, 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 $12.2 billion at December 31, 2018 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, 2018. The total capital costs were approximately $1.8 billion in 2018.

($ millions)	Acquisition Costs (2)			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	5.9	5.5	31.5	1,061.2
U.S.	6.6	4.7	88.4	588.7
Total	12.5	10.2	119.9	1,649.9

Notes:
(1) Costs incurred exclude capitalized administration.
(2) Excludes disposition proceeds of $355.7 million and $7.5 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 2019 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							
Southeast Saskatchewan and Manitoba	21,505	—	45,297	13,717	40,301	5,423	88,140
Southwest Saskatchewan (2)	10,076	5,135	21,979	471	14,675	1,590	40,372
Alberta	7,224	—	641	2,545	742	12,043	12,541
Total CANADA(1)	38,804	5,135	67,917	16,733	55,719	19,056	141,052
U.S.							
North Dakota and Montana	26	—	12,379	2,294	6,830	1	15,838
Utah	—	—	18,755	1,461	22,173	—	23,911
Total U.S.(1)	26	—	31,134	3,755	29,003	1	39,749
Total Corporate(1)	38,830	5,135	99,051	20,488	84,722	19,057	180,801

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

Production at Viewfield in southeast Saskatchewan was approximately 51,500 boe per day in 2018, accounting for 28% of the Corporation's Proved production estimate in the Crescent Point Reserve Report. Remaining areas each account for a small portion of the Corporation's production estimates for 2019.

The following table discloses, for each product type, the gross volume of production estimated by GLJ and Sproule for 2019 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							
Southeast Saskatchewan and Manitoba	24,491	—	52,943	15,528	46,277	6,275	101,720
Southwest Saskatchewan (2)	11,260	5,278	26,198	554	17,392	1,679	46,468
Alberta	8,493	—	1,307	2,858	1,461	12,918	15,054
Total CANADA(1)	44,244	5,278	80,448	18,940	65,130	20,872	163,243
U.S.							
North Dakota and Montana	27	—	14,553	2,643	7,861	1	18,533
Utah	—	—	21,935	1,605	24,375	—	27,602
Total U.S.(1)	27	—	36,488	4,248	32,235	1	46,135
Total Corporate(1)	44,271	5,278	116,936	23,188	97,365	20,873	209,378

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

Production at Viewfield in southeast Saskatchewan was approximately 57,000 boe per day in 2018, accounting for 27% of the Corporation's total Proved plus Probable production estimate in 2019. Remaining areas each account for a small portion of the Corporation's production estimates for 2019.

Production History

The following tables disclose, on a quarterly and annual basis for the year ended December 31, 2018, 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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Light and Medium Crude Oil (bbls/d)	40,900	41,735	34,884	34,316	37,933
Heavy Crude Oil (bbls/d)	5,079	4,878	4,884	4,668	4,876
Tight Oil (bbls/d)	69,841	69,669	62,558	64,314	66,569
NGLs (bbls/d)	16,275	15,260	19,325	16,929	16,955
Shale Gas (Mcf/d)	55,389	56,484	52,991	56,150	55,249
Conventional Natural Gas (Mcf/d)	28,509	29,063	26,913	23,224	26,912
Total (boe/d)	146,078	145,800	134,968	133,456	140,027
U.S.					
Light and Medium Crude Oil (bbls/d)	891	979	902	473	810
Heavy Crude Oil (bbls/d)	—	—	—	—	—
Tight Oil (bbls/d)	24,601	28,271	30,918	36,510	30,110
NGLs (bbls/d)	2,500	2,674	2,932	3,281	2,850
Shale Gas (Mcf/d)	21,213	20,261	23,805	21,255	21,640
Conventional Natural Gas (Mcf/d)	4,872	4,302	3,522	5,607	4,575
Total (boe/d)	32,340	36,018	39,307	44,741	38,139
TOTAL					
Light and Medium Crude Oil (bbls/d)	41,791	42,714	35,786	34,789	38,743
Heavy Crude Oil (bbls/d)	5,079	4,878	4,884	4,668	4,876
Tight Oil (bbls/d)	94,442	97,940	93,476	100,824	96,679
NGLs (bbls/d)	18,775	17,934	22,257	20,210	19,805
Shale Gas (Mcf/d)	76,602	76,745	76,796	77,405	76,889
Conventional Natural Gas (Mcf/d)	33,381	33,365	30,435	28,831	31,487
Total (boe/d)	178,418	181,818	174,275	178,198	178,166

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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Prices Received – net of hedging	63.36	66.27	66.43	50.53	61.94
Royalties	(9.93)	(10.97)	(12.92)	(9.07)	(10.71)
Production Costs(1)	(14.56)	(15.06)	(16.15)	(15.30)	(15.23)
Transportation Costs(1)	(2.10)	(2.33)	(2.24)	(2.28)	(2.24)
Netback	36.77	37.91	35.12	23.88	33.76
U.S.					
Prices Received – net of hedging	64.91	72.46	76.00	58.01	69.53
Royalties	(18.12)	(19.19)	(19.83)	(16.14)	(18.69)
Production Costs(1)	(15.89)	(14.33)	(14.56)	(11.62)	(14.42)
Transportation Costs(1)	(0.95)	(0.30)	(0.22)	(0.85)	(0.54)
Netback	29.95	38.64	41.39	29.40	35.88
TOTAL					
Prices Received – net of hedging	63.39	66.41	66.67	50.63	62.10
Royalties	(10.10)	(11.16)	(13.10)	(9.16)	(10.88)
Production Costs(1)	(14.59)	(15.04)	(16.11)	(15.25)	(15.22)
Transportation Costs(1)	(2.07)	(2.28)	(2.19)	(2.27)	(2.20)
Netback	36.63	37.93	35.27	23.95	33.80

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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Prices Received	51.36	65.35	73.67	38.19	57.30
Royalties	(16.30)	(17.81)	(22.42)	(10.20)	(16.75)
Production Costs(1)	(11.10)	(13.07)	(14.97)	(10.96)	(12.53)
Transportation Costs(1)	(1.66)	(1.53)	(1.66)	(1.82)	(1.67)
Netback	22.30	32.94	34.62	15.21	26.35
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs(1)	—	—	—	—	—
Transportation Costs(1)	—	—	—	—	—
Netback	—	—	—	—	—
TOTAL					
Prices Received	51.36	65.35	73.67	38.19	57.30
Royalties	(16.30)	(17.81)	(22.42)	(10.20)	(16.75)
Production Costs(1)	(11.10)	(13.07)	(14.97)	(10.96)	(12.53)
Transportation Costs(1)	(1.66)	(1.53)	(1.66)	(1.82)	(1.67)
Netback	22.30	32.94	34.62	15.21	26.35

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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Prices Received – net of hedging	63.04	68.18	67.78	48.78	62.03
Royalties	(7.29)	(7.53)	(9.07)	(5.20)	(7.27)
Production Costs(1)	(14.49)	(15.50)	(16.48)	(14.77)	(15.29)
Transportation Costs(1)	(2.97)	(3.36)	(2.75)	(3.20)	(3.07)
Netback	38.29	41.79	39.48	25.61	36.40
U.S.					
Prices Received – net of hedging	70.46	76.98	79.87	62.50	71.98
Royalties	(19.62)	(19.23)	(20.22)	(15.13)	(18.31)
Production Costs(1)	(17.25)	(15.23)	(15.30)	(12.51)	(14.82)
Transportation Costs(1)	(0.46)	(0.78)	(0.45)	(0.90)	(0.59)
Netback	33.13	41.74	43.90	33.96	38.26
TOTAL					
Prices Received – net of hedging	64.97	70.72	71.78	53.75	65.13
Royalties	(10.50)	(10.91)	(12.76)	(8.80)	(10.71)
Production Costs(1)	(15.20)	(15.42)	(16.09)	(13.95)	(15.15)
Transportation Costs(1)	(2.32)	(2.62)	(1.99)	(2.36)	(2.30)
Netback	36.95	41.77	40.94	28.64	36.97

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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Prices Received	32.37	34.05	31.72	32.80	32.67
Royalties	(2.10)	(2.30)	(2.65)	(2.23)	(2.34)
Production Costs(1)	(6.76)	(7.25)	(6.54)	(9.12)	(7.40)
Transportation Costs(1)	(0.39)	(0.53)	(0.54)	(0.92)	(0.60)
Netback	23.12	23.97	21.99	20.53	22.33
U.S.					
Prices Received	42.46	40.63	44.07	32.59	39.57
Royalties	(9.42)	(9.56)	(9.90)	(6.93)	(8.86)
Production Costs(1)	(10.33)	(7.92)	(8.23)	(6.28)	(8.04)
Transportation Costs(1)	(0.50)	(0.50)	(0.35)	(0.33)	(0.41)
Netback	22.21	22.65	25.59	19.05	22.26
TOTAL					
Prices Received	33.71	35.04	33.35	32.76	33.66
Royalties	(3.07)	(3.38)	(3.60)	(2.99)	(3.27)
Production Costs(1)	(7.24)	(7.35)	(6.76)	(8.66)	(7.49)
Transportation Costs(1)	(0.41)	(0.53)	(0.52)	(0.82)	(0.57)
Netback	22.99	23.78	22.47	20.29	22.33

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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Prices Received - net of hedging	2.86	1.83	2.16	2.65	2.37
Royalties	(0.24)	0.01	(0.14)	(0.18)	(0.13)
Production Costs(1)	(0.60)	(0.34)	(0.49)	(0.73)	(0.54)
Transportation Costs(1)	(0.18)	(0.15)	(0.18)	(0.20)	(0.18)
Netback	1.84	1.35	1.35	1.54	1.52
U.S.					
Prices Received - net of hedging	2.99	2.69	3.36	5.71	3.69
Royalties	(0.77)	(0.87)	(0.50)	(1.87)	(0.99)
Production Costs(1)	(0.78)	(0.55)	(0.69)	(1.30)	(0.83)
Transportation Costs(1)	(0.60)	(0.98)	(0.16)	(0.31)	(0.61)
Netback	0.84	0.29	2.01	2.23	1.26
TOTAL					
Prices Received - net of hedging	2.90	2.06	2.53	3.49	2.75
Royalties	(0.38)	(0.22)	(0.25)	(0.65)	(0.38)
Production Costs(1)	(0.65)	(0.39)	(0.55)	(0.89)	(0.62)
Transportation Costs(1)	(0.30)	(0.37)	(0.18)	(0.23)	(0.30)
Netback	1.57	1.08	1.55	1.72	1.45

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, 2018	June 30, 2018	Sept. 30, 2018	Dec. 31, 2018	2018
CANADA					
Prices Received - net of hedging	2.75	2.18	2.18	2.40	2.38
Royalties(2)	0.46	0.41	0.36	0.54	0.44
Production Costs(1)	(0.58)	(0.40)	(0.50)	(0.66)	(0.53)
Transportation Costs(1)	(0.32)	(0.40)	(0.35)	(0.30)	(0.34)
Netback	2.31	1.79	1.69	1.98	1.95
U.S.					
Prices Received - net of hedging	3.41	3.41	2.58	3.35	3.24
Royalties	(0.65)	(0.57)	(0.50)	(0.69)	(0.61)
Production Costs(1)	(0.89)	(0.69)	(0.53)	(0.76)	(0.73)
Transportation Costs(1)	(0.35)	(0.37)	(0.43)	(0.24)	(0.34)
Netback	1.52	1.78	1.12	1.66	1.56
TOTAL					
Prices Received - net of hedging	2.84	2.34	2.23	2.58	2.50
Royalties(2)	0.30	0.28	0.26	0.30	0.28
Production Costs(1)	(0.63)	(0.44)	(0.50)	(0.68)	(0.56)
Transportation Costs(1)	(0.32)	(0.39)	(0.36)	(0.29)	(0.34)
Netback	2.19	1.79	1.63	1.91	1.88

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, 2018 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							
Southeast Saskatchewan and Manitoba	23,412	—	41,882	14,200	39,372	6,415	87,125
Southwest Saskatchewan (2)	7,469	4,876	23,908	490	15,401	3,618	39,914
Alberta	7,052	—	779	2,265	476	16,879	12,988
Total CANADA(1)	37,933	4,876	66,569	16,955	55,249	26,912	140,027
U.S.							
North Dakota and Montana	750	—	12,152	1,605	5,773	185	15,500
Utah	60	—	17,958	1,245	15,867	4,390	22,639
Total U.S.(1)	810	—	30,110	2,850	21,640	4,575	38,139
Total(1)	38,743	4,876	96,679	19,805	76,889	31,487	178,166

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

ADDITIONAL INFORMATION RESPECTING CRESCENT POINT

Directors and Officers

Crescent Point has a board of directors currently consisting of ten individuals. The directors are elected by 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
Derek Christie Calgary, Alberta	Senior Vice President, Exploration and Corporate Development	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
Scott Tuttle Calgary, Alberta	Senior Vice President, Human Resources and Corporate Services	Not applicable
Robert F. Heinemann Plano, Texas	Director and Chairman	2014
Rene Amirault (4) (8) Calgary, Alberta	Director	2014
Peter Bannister (3) (4) (8) Calgary, Alberta	Director	2003
Laura A. Cillis (1) (2) Calgary, Alberta	Director	2014
John P. Dielwart (7) Calgary, Alberta	Director	
Francois Langlois (3) (4) (5) (6) Calgary, Alberta	Director	2018
Ted Goldthorpe (1) (5) New York, New York	Director	2017
Mike Jackson (1) (2) (5) Calgary, Alberta	Director	2016
Barbara Munroe (2) (5) Calgary, Alberta	Director	2016
Gerald A. Romanzin (1) (3) (8) Calgary, Alberta	Director	2004

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) Mr. Langlois was elected to the Board at Crescent Point's 2018 Annual General Meeting.
(7) Mr. Dielwart's appointment to the Board will be effective March 7, 2019.
(8) Mr. Amirault, Mr. Bannister and Mr. Romanzin have indicated their intention to retire from the Board in 2019.

As at February 14, 2019, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 1,712,335 Common Shares, representing approximately 0.3% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 0.6% 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, a role he has held since September 2018. Prior to his current position, Mr. Bryksa was Vice President, Engineering West and has held a number of senior management roles with Crescent Point since joining the Corporation in 2006. Mr. Bryksa has directly overseen the development and operations of each of Crescent Point's core assets, most recently the Shaunavon, Uinta Basin, North Dakota, Viking, Swan Hills and other Alberta resource plays, including the East Shale Duvernay.

Mr. Bryksa has spent 16 years as a professional engineer in the oil and gas industry, working with companies such as Enerplus Resources Fund and McDaniel and 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, Direct Energy Marketing Ltd. and Shell Trading Gas and Power Canada Ltd. Prior to 2001, he was a senior manager at PricewaterhouseCoopers LLP.

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

Ryan Gritzfeldt, Chief Operating Officer

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

Mr. Gritzfeldt is a member of the APEGA. He holds a Bachelor of Applied Science degree in industrial systems engineering from the University of Regina.

Derek Christie, Senior Vice President, Exploration and Corporate Development

Derek Christie is the Senior Vice President, Exploration of Crescent Point, a role he has held since June 2018. He has held numerous senior management positions since January 2010 with Crescent Point, including Senior Vice President, Exploration & Geosciences, Vice President, Exploration & Geosciences and Vice President, Geosciences. Mr. Christie is a Professional Geologist with over 25 years of experience across North America in both conventional and unconventional reservoir exploration and development. He has been with Crescent Point since 2007 and has worked in the oil and gas industry since 1991, having held a variety of technical and management positions with companies including Shelter Bay, Mission Oil and Gas Inc., StarPoint Energy Ltd., Vintage Petroleum Canada Inc. and Rio Alto Exploration Ltd.

Mr. Christie is currently a member of the board of directors of Boulder Energy Ltd. and Highrock Resources Ltd. He holds a Bachelor of Science degree in Geology from the University of Calgary and is a member of the APEGA, APEGS and the Association of Professional Engineers and Geoscientists of Manitoba ("**APEGM**").

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 June 2018. Since joining the company 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.

Scott Tuttle, Senior Vice President, Human Resources and Corporate Services

Appointed as Senior Vice President, Human Resources and Corporate Services in 2018, Mr. Tuttle is a seasoned HR executive with domestic and international oil & gas experience in small, mid, and large-cap organizations. Before joining the company, he was Corporate Director (SVP), People & Organization with Repsol SA in Madrid, and prior to that he held the top global executive HR role at Talisman Energy, Calfrac Well Services and Nexen Chemicals/Canexus Ltd.

Mr. Tuttle holds Bachelor degrees in Arts & Sciences and Education from the University of Saskatchewan, an MBA from the University of New England, and is a graduate of the MIT Sloan Management & Leadership Program. He is a Chartered Professional in HR (Canada), Senior Professional in HR (USA) and a Certified HR Executive (Canada).

Robert F. Heinemann, Chairman and Director

Mr. Robert F. Heinemann is an oil and gas executive who brings more than 30 years of experience to the Board of Directors. Most recently, he served as President, Chief Executive Officer and director of Berry Petroleum Company ("**Berry**"), where he developed and executed that company's growth and capital allocation strategies. He served as a director of Berry from 2002 until 2013, and as President and Chief Executive Officer from 2004 through 2013. Previously, Mr. Heinemann worked for Halliburton Company and Mobil Corporation in a number of operational, technology, management and executive roles of increasing responsibility.

Mr. Heinemann serves on the board of directors of QEP Resources, Inc., Great Western Oil and Gas Company, LLC and Chaparral Energy, Inc. He is a member of the Society of Petroleum Engineers. He holds a Bachelor of Engineering and a Doctorate in chemical engineering from Vanderbilt University.

Rene Amirault, Director

Mr. Rene Amirault was appointed as the President and Chief Executive Officer of Secure Energy Services Inc. (" **Secure**") in March 2007 and was elected a director and appointed as Chairman of the Secure board on June 1, 2007. From January 2006 to March 2007, he was an independent businessman. Mr. Amirault held various roles at Tervita Corporation from August 1994 to January 2006, including Vice President roles in Sales and Marketing, Business Development and Corporate Development. Mr. Amirault held various positions with Imperial Oil Ltd. from 1981 to 1994. Mr. Amirault has indicated his intention to retire from the Crescent Point Board before the 2019 Annual General Meeting.

Mr. Amirault received a Certified General Accountant designation in June 1985.

Peter Bannister, Director

Mr. Peter Bannister is President of Destiny Energy Inc., a private oil and gas company. Mr. Bannister has worked in the oil and gas industry since 1982, having held a variety of roles with companies such as Mission Oil and Gas Inc., StarPoint Energy Inc., Impact Energy Inc., Startech Energy Ltd., Boomerang Resources Ltd., Laurasia Resources Ltd. and Sproule Associates Ltd. Mr. Bannister has indicated his intention to retire from the Crescent Point Board in 2019.

Mr. Bannister is a member of the APEGA and serves on the board of directors of Cequence Energy Ltd. Formerly, he was a director of Surge Energy Inc., Shelter Bay Energy Inc., Mission Oil and Gas Inc., Breaker Energy Ltd., Impact Energy Inc., Boomerang Resources Ltd., Laurasia Resources Ltd. and New Star Energy Ltd, Mr. Bannister holds a Bachelor of Science degree from the University of Calgary in geology with a minor in economics.

Laura A. Cillis, Director

Ms. Laura A. Cillis worked as an oil and gas executive with more than 25 years of leadership and financial experience in the oilfield services industry. Ms. Cillis serves on the board of directors of Solium Capital Inc., is a member of its Governance and Human Resources Committee and the chair of its Audit Committee. She previously served as a director and member of the Audit Committee of Enbridge Income Fund Holdings Inc. from July 2016 until its privatization in November 2018 and was a director and member of the Audit, Finance and Risk Committee and chair of the Safety & Reliability Committee of Enbridge Pipelines Inc. Ms. Cillis held the position of Senior Vice President, Finance and Chief Financial Officer for Calfrac Well Services Ltd. from November 2008 to June 2013.

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. She earned a Bachelor of Commerce degree from the University of Alberta.

John P. Dielwart, Director (Effective March 7, 2019)

Mr. Dielwart is one of ARC Resources Ltd.'s founders, who held the position of Chief Executive Officer from 2001 to 2013 and currently serves on its board of directors. He is also Vice-Chairman and Director of ARC Financial Corp. and a member of its Investment and Governance Committees. Mr. Dielwart received a Bachelor of Science degree in Civil Engineering with Distinction from the University of Calgary. He is a Professional Engineer, an Institute of Corporate Directors Certified Director and a Past-Chairman of the Board of Governors for the Canadian Association of Petroleum Producers. In 2015, Mr. Dielwart was inducted into the Calgary Business Hall of Fame and received the Oil and Gas Council's Canadian Lifetime Achievement Award in 2018.

Francois Langois, 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 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 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 and serves on the board of directors for Her Justice and Capitalize for Kids.

Mike Jackson, Director

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 and companies on M&A transactions aggregating over $28 billion. Mr. Jackson joined the Crescent Point Board 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.

Barbara Munroe, Director

Ms. Barbara Munroe has worked as a lawyer since being admitted to the Law Society of Alberta in 1991 and brings 26 years of legal experience and industry diversification to the Board. Currently, Ms. Munroe is serving as Executive Vice President, Corporate Services and General Counsel for WestJet Airlines, a position 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 Association of Corporate Counsel, Governance Professionals of Canada and the Institute of Corporate Directors. She holds a Bachelor of Commerce, Finance degree and a Bachelor of Laws degree both from the University of Calgary.

Gerald A. Romanzin, Director

Mr. Gerald Romanzin is an independent Calgary businessman who serves as a director of Athabasca Minerals Inc. Previously, he held a variety of senior roles with the TSX Venture Exchange, including Executive Vice President and Acting President, and was the Executive Vice President of the Alberta Stock Exchange, prior to its conversion. Mr. Romanzin has indicated his intention to retire from the Crescent Point Board in 2019.

Formerly, Mr. Romanzin served as a director of Trimac Transportation Ltd., FET Resources Ltd., Ketch Resources Ltd., Ketch Resources Trust, Cadence Energy Inc., Kereco Energy Ltd., Flowing Energy Corporation, Petrowest Corporation and Porto Energy Corp. Mr. Romanzin is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta and holds a Bachelor of Commerce degree from the University of Calgary.

Bankruptcies and Cease Trade Orders

Other than as described below, 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.

Gerald A. Romanzin

Mr. Romanzin resigned from his position as a director of Porto Energy Corp. (" **Porto**") on May 30, 2014, following the decision by Porto's directors and management to wind-down Porto's operations due to capital constraints. Cease trade orders against Porto were subsequently issued by the Alberta, British Columbia, Manitoba and Ontario Securities Commissions and such cease trade orders remain in effect.

Mr. Romanzin also resigned his position as a director of Petrowest Corporation (" **Petrowest**") on August 13, 2017 upon the appointment of a receiver. Cease trade orders against Petrowest were subsequently issued by Alberta and Ontario Securities Commissions and such cease trade orders remain in effect.

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 "**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, 2018 the Corporation is authorized to issue up to 14,256,482 Common Shares, of which the Corporation had 3,241,684 restricted shares outstanding at December 31, 2018.

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 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 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. 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 U.S. 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 corporate performance metrics over a three year performance period. For grants in 2017 and 2018, the Corporation uses three corporate performance metrics to determine PSU achievement: total shareholder return, production per share growth plus yield, and drilling and completions capital rate of return.

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 2,246,314 PSUs outstanding at December 31, 2018.

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, 2018, there are 2,048,115 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, 2018, the Corporation had a $3.5 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 June 10, 2021. The current maturity date of the Bi-Lateral Credit Facility is June 10, 2021. 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 0.50% 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, 2018, the Corporation had approximately $2.0 billion drawn under its credit facilities.

At December 31, 2018, the Corporation had approximately $2.3 billion of senior guaranteed notes outstanding of which $99.8 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$1.45 billion senior guaranteed notes, the Corporation entered into cross currency swaps to hedge its foreign exchange exposure, fixing a notional amount of $1.58 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.

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 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 National Energy Board ("**NEB**"). 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 NEB 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 by 325,000 barrels per day (the "**Curtailment**"). The Curtailment was reduced by 75,000 barrels per day commencing February 1, 2019. The Curtailment is expected to be reduced in the future as the amount of crude oil in storage in Alberta is reduced and the capacity of pipelines and shipments of crude oil by rail increases for the remainder of 2019. Curtailment will be set at the operator level, leaving the first 10,000 barrels per day from a given operator exempt from the Curtailment. It is not yet known what effect the Curtailment will have on the price and marketing of oil in Canada. Curtailment is not expected to have a particular effect on Crescent Point beyond the general effects on the industry.

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 NEB and the government of Canada and in the United States is regulated principally by the FERC and the United States Department of Energy ("**DOE**"). The FERC, which has the authority under the Natural Gas Act of 1938 (" **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 FERC-regulated transmission facilities and federally unregulated gathering facilities is the subject of on-going litigation and, therefore, is subject to change based on future determinations. The FERC regulates interstate natural gas transportation rates and service conditions under the NGA and the Natural Gas Policy Act of 1978 ("**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 NEB 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 NEB 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 NEB to import or export natural gas. Alternatively, natural gas can be imported into Canada or exported from Canada pursuant to an order from the NEB. 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 carries 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. If CUSMA is ratified it will likely take effect in 2019 or 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 all parties, Crescent Point does not anticipate any material change to its operations or marketing activities as a result of the new agreement if 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

Pursuant to the Old Framework a number of incentive programs, such as the Deep Oil Exploratory Well Program, the Enhanced Oil Recovery Royalty Program ("**EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the " **IETP**"), were created.

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.

With respect to 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 Programs ceased being accepted as of December 31, 2016; however, the EOR Program continues to apply to schemes previously approved thereunder.

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, with producing intervals that are deeper than 2,000 metres.

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

Under the Modernized Framework, two strategic programs have been recently 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 either "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 either "fourth tier oil", "third tier oil", "new oil", or "old oil". Depending on the categorization and classification of the oil, monthly production, and a prescribed reference price determined monthly by the Saskatchewan Ministry of Economy ("**SME**"), the royalty reserved to the Crown ranges from 0% to 45%.

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 either "fourth tier gas", "third tier gas", "new gas", or "old gas". Depending on the categorization and classification of the natural gas, monthly production, and a reference price, the royalty reserved to the Crown ranges from 0% to 45%. 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 ("**VWD**"); the horizontal well drilling incentive ("**HWD**"); and the exploratory gas well drilling incentive ("**EGWD**"). The VWD 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 16,000 m^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 HWD is very similar to the VWD, 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 EGWD 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 showing the well produces gas from an area which has not generally been produced from. The incentive applies to the produced volume up to 25,000,000 m^3.

Manitoba

In Manitoba, the royalty amount payable on oil produced from Crown land depends on the classification of the oil produced. Production is divided into the following categories: (i) "old oil" (being oil produced from a well that does not qualify as new oil, third tier oil or holiday oil; (ii) "new oil" (being oil that is not third tier oil and is produced from a well drilled on or after April 1, 1974 and prior to April 1, 1999, from an abandoned well re-entered during that period, from an old oil well as a result of an enhanced recovery project implemented during that period, or from a horizontal well); (iii) "third tier oil" (being oil produced from a vertical well drilled after April 1, 1999, an abandoned vertical well re-entered on or after that date, an inactive vertical well activated after that date, a marginal well that has undergone a major workover, or from an old oil well or a new oil well as a result of an enhanced recovery project implemented after that date); or (iv) "holiday oil" (being oil that is exempt from any royalty or tax payable).

Royalty rates are calculated on a sliding scale and based on the monthly oil production from a spacing unit, or oil production allocated to a unit tract under a unit agreement or unit order from the Minister of Growth, Enterprise and Trade. For horizontal wells, the royalty on oil produced from Crown lands is calculated per spacing unit based on the amount of oil production allocated to the spacing units within the drainage unit of a well in accordance with the applicable regulations.

Royalties payable on natural gas production from Crown lands are equal to 12.5% of the volume of natural gas sold, calculated monthly. There is no Crown royalty payable on gas consumed as lease fuel.

Manitoba legislation levies a tax on production from freehold oil and gas rights and provides that the operator of a well is responsible for the payment of such tax. The freehold production tax payable on oil is calculated on a sliding scale based on the monthly production volume and the classification of oil as old oil, new oil, third tier oil or holiday oil. Producers of natural gas from freehold lands in Manitoba are required to pay a monthly freehold production tax equal to 1.2% of the volume sold. There is no freehold production tax payable on gas consumed as lease fuel.

Incentive Programs

The Government of Manitoba maintains a Drilling Incentive Program (the " **Program**") with the intent of promoting investment in the development of petroleum resources. The Program provides the licensee of newly drilled wells, or qualifying wells where a major workover has been completed, with a "holiday oil volume". Under the Program, a new well drilled or a well receiving workover incentive, after December 31, 2013 and before January 1, 2019 will be required to pay a minimum Crown royalty, or if the well is producing from freehold oil and gas rights, a minimum production tax while holiday oil is produced. To date, the Government of Manitoba has not announced a successor to the Program, which was scheduled to terminate January 1, 2019.

The Program consists of the following components:

Vertical Well Incentive provides the licensee of a vertical development well or exploratory well drilled between December 31, 2013 and January 1, 2019 with 500 m^3 of holiday oil volume. To qualify the well must be drilled less than 1.6 km from the nearest well cased for production from the same or a deeper zone.

Exploration and Deep Well Incentive provides the licensee of an exploration well or a deep development well drilled between December 31, 2013 and January 1, 2019 with a holiday oil volume as follows: (i) for a well drilled more than 1.6 km from a well cased for production from the same zone or a deeper zone, a holiday oil volume of 4,000 m^3 is earned; (ii) for an exploratory well drilled below the Birdbear Formation, a holiday oil volume of 8,000 m^3 is earned; and (iii) for a development well completed for production in the Birdbear or deeper formation, a holiday oil volume of 8,000 m^3 is earned.

Horizontal Well Incentive provides the licensee of a horizontal well drilled between December 31, 2013 and January 1, 2019 with a holiday oil volume of 8,000 m^3.

Marginal Well Major Workover Incentive provides the licensee of a marginal well where a major workover is completed prior to January 1, 2019 with a holiday oil volume of 500 m^3, with a marginal oil well defined as an abandoned well or a well that was either not operated over the previous 12 months or produced oil at an average rate of less than 3 m^3 per operating day.

Pressure Maintenance Project Incentive provides a one year exemption from the payment of Crown royalty or freehold production tax on production allocated to a unit tract in which an injection well is drilled or a well is converted to water injection. Wells eligible for the incentive include those wells drilled for the purpose of injection in an approved enhanced recovery project as well as vertical or horizontal wells that are converted to injection. For wells converted to injection between December 31, 2013 and January 1, 2019 the exemption period is extended to 18 months, if the well has remaining holiday oil volume.

Solution Gas Conservation Incentive provides an exemption from the payment of Crown royalties and production taxes for new solution gas projects implemented after December 31, 2013 and effective until December 31, 2018 and subject to approval from the Director of Petroleum.

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.

Utah

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 and state royalty rates for onshore oil and gas are each 12.5%. Production in Utah may be subject to oil and gas severance taxes. Utah severance tax includes exemptions available for stripper wells, wells within their first six months of production, and wildcat wells within their first twelve months of production. Royalties payable under private oil and gas leases in Utah are determined by negotiations between the mineral owner and the lessee.

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 *Climate Change and Emissions Management 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 the Ministry of the Economy in the Licensee Liability Rating Program Guideline 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, Montana, and Utah 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.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and gas industry in general. While we believe that we are in compliance, in all material respects, with current applicable environmental laws and regulations and have not experienced any material adverse effect from compliance with these environmental requirements, there is no assurance that this trend will continue in the future.

President Trump has indicated that he would work to ease regulatory burdens on industry and on the oil and gas sector, including environmental regulations. However, any executive orders the President may issue 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. The CERCLA currently excludes petroleum from its definition of "hazardous substance".

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 has 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. In the event that the EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Any such change 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 the 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. 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 "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 Indian 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.

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 wetlands and other waters of the United States unless authorized by an appropriately issued permit. 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 will provide coverage for a five-year period and will take 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 (" **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.

Many states currently independently regulate hydraulic fracturing operations in the state, including Utah, 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 and National Emission Standards for Hazardous Air Pollutants programs. *Clean Air Act* regulations include New Source Performance Standards for completions of hydraulically fractured wells.

The Emergency Planning and Community Right-to-Know Act (" **EPCRA**") requires certain facilities to disseminate information on chemical inventories to employees as well as 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

In Alberta, GHG emissions are regulated under the *Specified Gas Reporting Regulation* ("**SGRR**") and the *Carbon Competitiveness Incentive Regulation* ("**CCIR**"). The SGRR requires facilities that emit 10,000 tonnes or more of GHGs per year to report their emissions to AEP annually. The CCIR requires Alberta facilities that emit more than 100,000 tonnes of GHGs per year in 2017 and subsequent years to reduce emissions intensity to an industry average or facility-specific benchmark. Companies may meet these requirements through improvements to their operations; by purchasing and retiring Alberta-based emission reduction or offset credits; by contributing to the provincial Climate Change and Emissions Management Fund; or by a combination of these actions. Crescent Point does not operate any facilities that are regulated by the CCIR.

In August 2015, the Alberta Government appointed a Climate Leadership Panel to provide advice to the government on the development of a comprehensive climate change strategy and to provide the AEP advice on a comprehensive set of policy measures to reduce GHG emissions in Alberta. On November 22, 2015, the government released the Climate Leadership Panel's Report to the Minister and the government announced that it would implement its recommendations on phasing out coal-fired power production, replacing two-thirds of that production with renewable energy and imposing a new economy-wide price on GHG emissions of $20 per tonne on January 1, 2017, rising to $30 per tonne on January 1, 2018. The government also enacted a new overall annual emissions limit of 100 megatons for the oil sands industry.

Alberta's *Climate Leadership Implementation Act* requires distributors of transportation and heating fuels to remit to the provincial government a carbon levy at a rate of $30 per tonne for transportation and heating fuels sold and distributed in the province. The distributors pass on the compliance costs to their customers, which results in non-agricultural and other non-exempt customers paying an additional 6.73 cents per litre for regular gasoline and $1.517 per GJ for natural gas in 2019.

Natural gas which is flared or used in the oil and gas production process will be subject to the carbon levy commencing January 1, 2023.

Methane emission reduction in the oil and gas industry is also a key to Alberta's GHG emission plan with a goal of reducing oil and gas methane emissions by 45% by 2025 from 2014 levels. New design specifications have been put in place by the AER for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards are also included in the regulatory requirements and will raise current standards for performance, monitoring, measurement and reporting. The AER has published directives requiring methane emission reductions commencing January 1, 2020.

On January 1, 2019, the Government of Saskatchewan brought into force *The Management and Reduction of Greenhouse Gases (Standards and Compliance) Regulations* (the "**MRGHGR**") to regulate greenhouse gas emissions in the province. Regulations under the MRGHGR require owners and operators of any facility that emits 25,000 tonnes or more of GHGs annually in 2017 or any subsequent year to register their facility with the Minister of Environment and establish a baseline emissions level and a baseline emissions intensity for the products produced at the facility. Registered upstream oil and gas facilities must reduce their GHG emissions intensity relative to a facility-specific baseline commencing January 1, 2020. We have facilities subject to these regulations.

On January 1, 2019 the Government of Saskatchewan brought into force *The Oil and Gas Emissions Management Regulations* (the "**OGEMR**") 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 commencing January 1, 2020. 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.

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. To date, Crescent Point does not operate any facilities that are regulated by the British Columbia GHG emissions regulations.

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**"). Previously, the federal government provided all Canadian provinces and territories a year to introduce their own carbon pricing models of either a cap and trade program or a carbon tax meeting a prescribed standard. For provinces that have failed to do so, including Saskatchewan, the federal government will begin to levy its own carbon tax on a broad set of fuels on April 1, 2019. The initial carbon tax is $20 per tonne of GHG emissions 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 addition, 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.

In June 2017, President Trump announced that the U.S. would initiate the formal process to withdraw from the Paris Agreement. Withdrawal will take a few years to implement due to the Paris Agreement's legal structure and language. 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 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 Canadian federal government is bringing into force on January 1, 2020 a new regulation under CEPA to reduce methane emissions from upstream oil and gas activities: the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)*. The regulation will impose both facility and equipment level requirements. Facilities that produce 60,000 m^3 of hydrocarbon gas in any of the past five years and facilities using pneumatic devices or compressors are covered by the proposed regulations, as well as certain hydraulic fracturing activities. The new regulations are expected to cover the majority of methane emission sources from upstream oil and gas activities.

However, the federal regulations will not apply in provinces which the federal government deems to have equivalent methane reduction regulations.

Methane emission limits will be set by the proposed federal regulations in the provinces which do not have equivalent regulations.

Beginning in 2020, operators of upstream oil and gas facilities (except single wellheads) will have to inspect their facilities three times a year with specialized infrared cameras or other devices that can detect fugitive methane leaks. Equipment found to be leaking will have to be repaired within 30 days if repairs are possible without shutting down the equipment. If repairs are not possible without shutting down the equipment, the repairs must be done before the volume of gas from the leak is larger than the volume of gas that would be released by shutting down the equipment.

In 2023, oil and gas facilities will have a limit of 1,250 m^3 per month on the volume of natural gas that they can vent during normal operations. Facilities that cannot reduce venting to the new limit will have to install conservation, flaring or incineration equipment to continue operating. Emergency venting will still be allowed.

In 2023, oil and gas facilities and ones with larger pumping rates will require controllers to be non or low methane emitting and certain pumps to be non-methane emitting. Potential exemptions may be created for operational needs or if there is no feasible technology available.

Beginning in 2020, existing and new compressors will have to meet certain methane emission limits depending on the size and type of compressor. Operators of non-compliant compressors will have to make modifications to bring their compressors into compliance. All operators will have to either continuously monitor or annually measure their emissions, excluding compressors that are equipped with emission conservation or destruction technology.

In 2020, the new regulations will require operators undertaking hydraulic fracturing activities outside of Alberta and British Columbia on wells with high gas-to-oil ratios to conserve, flare or incinerate any methane that would otherwise be vented. Alberta and British Columbia already have provincial measures which cover these activities.

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

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.

As part of Crescent Point’s ongoing commitment to reduce emissions, the Company contributed to a climate change initiatives fund directed to environmental initiatives. To date, $65.3 million has been contributed towards emissions reduction and $51.2 million has been expended to reduce emissions and to meet and exceed provincial and federal regulations. In 2018, the Company spent a total of $2.4 million on emissions reduction, primarily to upgrade facilities in Saskatchewan. These upgrades have reduced our emissions, which continue to meet or fall below provincial and federal emission limits.

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, 2018, Crescent Point owned approximately 27,182 gross (19,709 net) wells for which abandonment and/or reclamation costs are expected to be incurred. During the 2018 financial year, Crescent Point spent approximately $25.3 million on well abandonments and environmental remediation activities. Crescent Point estimates that it will spend approximately $26.9 million on well abandonments and environmental remediation and reclamation activities in 2019 and has budgeted accordingly. Crescent Point has estimated the net present value (discounted at approximately 2.25% per annum) of its total decommissioning liability (wells and facilities) to be approximately $1.2 billion as at December 31, 2018, based on estimated undiscounted cash flows of approximately $1.3 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 (OMS);
- 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.

Recent Tax Legislation in the United States

On December 22, 2017, tax legislation known as the Tax Cuts and Jobs Act ("TCJA") was enacted into law, which significantly changes existing U.S. tax law and includes numerous provisions that affect our business such as reducing the U.S. federal statutory tax rate and limiting certain deductions. The TCJA reduces the U.S. federal statutory tax rate from 35% to 21% effective January 1, 2018. The TCJA includes a base erosion anti-abuse tax ("BEAT") measure that taxes certain payments between a U.S. corporation and its non-U.S. affiliates. In addition, the TCJA limits interest deductions and also disallows deductions for interest and royalty payments from U.S. companies to non-U.S. affiliates that are hybrid payments or made to hybrid entities. In December 2018, proposed regulations to the TCJA were released which, if adopted, would further expand the scope of the anti-hybrid rules to limit interest deductions effective January 1, 2019.

During the fourth quarter of fiscal year 2017, we recorded an estimated expense of CAD $107.5 million related to the TCJA, due entirely to the impact of changes in the tax rate.

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.

Failure to achieve our transition plan goals may have a material adverse effect on our business.

In 2018, Crescent Point's new leadership team initiated a plan to transition the Corporation to a more efficient and focused business with a stronger balance sheet. This transition plan includes the revision and reprioritization of the Corporation's strategy based on key value drivers including balance sheet improvement, disciplined capital allocation and cost reductions. Management has already taken certain actions in furtherance of this plan, including allocating proceeds from recent dispositions to reduce debt, rescheduling capital investment plans and streamlining the Corporation's executive structure with fewer positions. However, as the transition remains in progress its further success is dependent on management's ability to identify and execute on further opportunities to meet the objectives of the transition plan. These opportunities may include, among other things, further streamlining of the Corporation's organizational structure and asset dispositions, including certain upstream and infrastructure assets. Furthermore, the successful realization of these opportunities may also be dependent on factors outside of the Corporation's control, including global commodity prices, political conditions in the jurisdictions in which Crescent Point operations, and general economic activity in the markets in which Crescent Point operates. There can be no assurance that the

Corporation will be able to achieve the stated objectives of its transition plan on a timely basis, and the failure to successfully execute this transition plan may have adverse consequences for the Corporation and materially affect the value of the Common Shares.

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. The AER's new Curtailment rules are unlikely to negatively impact our production and sale of oil. In addition, the Government of Saskatchewan has thus far not announced any plans to institute their own curtailment regime.

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 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, 2018, approximately 8% 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 wilful 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 or refinery capacity;
- blowouts or other accidents;
- 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 may have a material adverse effect on our business.

The Corporation has completed a number of acquisitions 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.

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 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. Recent and continuing 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.

Approximately 56% of Crescent Point's Utah assets involve tribal trust minerals. Operation of oil and gas interests on Native American tribal lands presents unique considerations and complexities that arise from the fact that Native American tribes are "dependent" sovereign nations located within states but are subject only to tribal laws and treaties with, and the laws and Constitution of, the United States. This creates an overlay of three jurisdictional regimes—Native American, federal and state. These considerations and complexities could arise around various aspects of Crescent Point's Utah operations, including real property considerations, permitting, employment practices, environmental matters and taxes.

Furthermore, because tribal property is considered to be held in trust by the federal government, before Crescent Point can take actions such as drilling, pipeline installation or similar actions, Crescent Point is required to obtain approvals from various federal agencies, including the Bureau of Indian Affairs and the BLM. Crescent Point is also required to obtain approvals from the Tribe for surface use access on certain of its properties. Gaining these approvals could result in delays in implementation of, or otherwise prevent Crescent Point from implementing, its development program.

Because of their sovereign status, Native American tribes also enjoy sovereign immunity from suit and may not be sued in their own courts or in any other court absent Congressional abrogation or a valid tribal waiver of such immunity.

Although the Tribe has sovereign immunity and generally may not be sued without its consent, a limited waiver of sovereign immunity and consent to suit has been granted in connection with the Tribe’s EDAs with Crescent Point.

These waivers were subject to various United States governmental approvals, which Crescent Point believes have been obtained. An enforceable waiver of sovereign immunity should allow Crescent Point to enforce its rights under the EDAs in a federal court. If any waiver of sovereign immunity with Crescent Point is held to be ineffective, including as a result of failing to obtain appropriate federal governmental approvals, Crescent Point and CPEUS could be precluded from judicially enforcing its rights and remedies against the Tribe.

Obtaining jurisdiction over a Native American tribe, such as the Tribe, can be difficult. Often, a commercial dispute with a Native American tribe or tribal instrumentality cannot be heard in federal court because the typical requirements for federal jurisdiction are absent. It is possible that neither a federal nor a state court would accept jurisdiction to resolve a matter involving a commercial dispute between Crescent Point or CPEUS and the Tribe, and no legal recourse to a state or federal court may be available to Crescent Point. Pursuant to the waivers of sovereign immunity previously obtained from the Tribe, the Tribe has waived its rights to have certain matters resolved in any tribal court or other proceeding of the Tribe. The Tribe has a tribal court system, and a federal or state court may defer to such tribal courts if, contrary to the waivers of sovereign immunity by the Tribe, the Tribe seeks or alleges its right to seek tribal proceedings for resolution of a dispute. The tribal courts may not reach the same conclusions that would be reached in state or federal courts.

Any state or federal court judgment requiring satisfaction or enforcement within tribal territories may require that an order for such enforcement be issued by tribal courts. Tribal courts do not have specific rules related to granting full faith and credit to judgments of courts of the United States or any state, except in limited circumstances.

Additionally, Crescent Point is subject to the Ute Tribal Employment Rights Ordinance (the " **Employment Act**"). The Employment Act requires that Crescent Point give preference in hiring to members of the Tribe meeting job description requirements. The Employment Act also requires Crescent Point to give preference to businesses owned by members of the Tribe when hiring contractors, provided they are market competitive (as defined in the Employment Act). These regulatory restrictions may negatively affect Crescent Point's ability to hire non-tribal employees and contractors.

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.

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, Montana and Utah, 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, Montana and Utah. 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. In 2015 and 2016, commodity prices were severely depressed. Continued 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;
- 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;
- 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 Saskatchewan Ministry of the Economy, the Manitoba Ministry of Conservation, Environment Canada and Climate Change, Health Canada, Transport Canada and the Department of Fisheries and Oceans, and, in the U.S., the EPA, the U.S. Bureau of Indian Affairs, the BLM, Energy and Minerals, the Tribe and the Utah Division of Oil, Gas and Mining. 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 carryout 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.

Crescent Point's oil and natural gas exploration and production operations in Utah occur on the Utah and Ouray Reservation (the " **Reservation**") lands and federal, state or private lands located outside those Reservation lands. Various federal agencies within the U.S. Department of the Interior, particularly the Bureau of Indian Affairs, the BLM and the Office of Natural Resources Revenue, may promulgate and enforce laws, regulations and/or other approval requirements addressing environmental conditions and pertaining to oil and natural gas operations on Reservation lands.

In addition, Crescent Point's oil and natural gas exploration and production operations in Utah, particularly those located outside the Reservation lands, may be subject to stringent federal, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to Crescent Point's Utah operations including the acquisition of a permit before conducting drilling or underground injection activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and the imposition of substantial liabilities for pollution resulting from operations. Numerous governmental authorities, such as the U.S. EPA, and analogous state agencies, including in Utah, 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.

The Canadian federal government brought into force on June 1, 2018 the GGPPA which imposes a carbon tax of $20 per tonne of GHG emissions beginning April 1, 2019 in each province and territory that does not have a carbon tax or cap and trade system meeting federal requirements, with the federal tax increasing $10 per tonne per year until it reaches $50 per tonne on April 1, 2022.

Further, both the Alberta and federal governments have introduced regulations to reduce methane emissions from the oil and gas sector by up to 45% by 2025 from 2014 levels. It is likely that the methane reduction regulations will materially impact the nature of oil and gas operations, including those carried out by Crescent Point. At present we have assessed the impact of the Saskatchewan methane reduction regulation and anticipate it will have minimal impact on our business and operations in the province. We are currently in the process of determining the impact of the Alberta and federal methane regulations on the business, operations and/or finances of Crescent Point.

In Saskatchewan, the MRGHGA came into force on January 1, 2019. Facilities that emit 25,000 tonnes or more of GHGs annually will be required to register their facility with the Minister of Environment and establish a baseline emissions level and a baseline emissions intensity for the products produced by the facility. Upstream oil and gas facilities that consume fuel must reduce their GHG emissions relative to a facility baseline commencing on January 1, 2019. 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. Future legislation in Manitoba, changes to federal legislation, as well as legislation in British Columbia, Alberta and Saskatchewan may require the restriction or reduction of GHG emissions or emissions intensity from our future operations and facilities, 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.

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 emissions of GHG under existing provisions of the *Federal Clean Air Act* (the "**CAA**"), including one rule that limits emissions of GHG 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 emissions of GHG, and many states have already taken legal measures to reduce emissions of GHG, 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 is issuing new regulations that limit emissions of GHG associated with our operations which will require us to incur costs to inventory and reduce emissions of GHG associated with our operations and which could adversely affect demand for the oil and natural gas that we produce. 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.*, 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 Alberta Energy Regulator (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 a recent Supreme Court of Canada 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 a great deal of 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.

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.

We do not currently own or operate rail transportation facilities or rail cars; however, 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.

The failure of the U.S. government to address 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, could afford 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 probable reserves are different than those in NI 51-101. As a consequence of the foregoing, our reserve estimates and production volumes in this AIF may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

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 (the "**Treaty**") 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.

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.

In 2018, the Corporation's payout ratio on a per Common Share diluted basis was 11%.

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

			Dividend per Common Share
January 2016	–	March 2016	$0.10
April 2016	–	December 2018	$0.03

Commencing in 2019, the Corporation expects to pay a quarterly dividend, which will be paid on the first business day of each quarter. Dividends are paid to Shareholders of record on the immediately preceding dividend record date.

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 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. The actual number of Common Shares that will be purchased under the NCIB

and the timing of any such purchases will be determined by the Corporation in management's discretion, subject to applicable securities laws. The NCIB expires on January 24, 2020.

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)
2018			
January	11.59	9.60	91,239
February	10.02	8.40	66,243
March	9.67	8.25	74,589
April	11.81	8.29	92,915
May	11.53	9.82	87,224
June	10.53	9.08	58,856
July	10.31	8.60	56,147
August	8.92	7.91	46,703
September	8.38	6.66	64,153
October	8.58	5.69	86,470
November	6.36	3.80	156,917
December	4.61	3.70	100,724
2019			
January	4.70	3.82	96,001
February	4.44	3.24	85,821

NYSE	High (US$)	Low (US$)	Volume (000's)
2018			
January	9.25	7.70	33,430
February	8.15	6.65	27,092
March	7.50	6.40	35,345
April	9.20	6.45	39,984
May	9.05	7.56	32,861
June	8.12	6.82	27,165
July	7.87	6.59	29,610
August	6.89	6.01	26,961
September	6.50	5.06	30,102
October	6.68	4.36	45,518
November	4.87	2.85	53,033
December	3.45	2.70	53,149
2019			
January	3.55	2.88	43,620
February	3.39	2.44	52,313

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.

Mr. Rene Amirault, a director of the Corporation, is the President and Chief Executive Officer of Secure Energy Services Inc., a company that provides services to the Corporation. The Board of Directors do not believe that any of the activities undertaken by Mr. Amirault or by Secure Energy Services Inc. interferes, or could be perceived to interfere, in any material way with his ability to act with a view to the best interests 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), Gerald A. Romanzin, 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 worked as an oil and gas executive with more than 25 years of leadership and financial experience in the oilfield services industry. Ms. Cillis serves on the board of directors of Solium Capital Inc., is a member of the Governance and Human Resources Committee and chair of its Audit Committee. She previously served as a director and member of the Audit Committee of Enbridge Income Fund Holdings Inc. from July 2016 until its privatization on November 2018 and was a director and member of the Audit, Finance and Risk Committee and chair of the Safety & Reliability Committee of Enbridge Pipelines Inc. Ms. Cillis held the position of Senior Vice President, Finance and Chief Financial Officer for Calfrac Well Services Ltd. from November 2008 to June 2013.
	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. She earned a Bachelor of Commerce degree from the University of Alberta.
Gerald A. Romanzin	Mr. Gerald Romanzin is an independent Calgary businessman who serves as a director of Athabasca Minerals Inc. Previously, he held a variety of senior roles with the TSX Venture Exchange, including Executive Vice President and Acting President, and was the Executive Vice President of the Alberta Stock Exchange, prior to its conversion. Mr. Romanzin has indicated his intention to retire from the Crescent Point Board in 2019.
	Formerly, Mr. Romanzin served as a director of Trimac Transportation Ltd., FET Resources Ltd., Ketch Resources Ltd., Ketch Resources Trust, Cadence Energy Inc., Kereco Energy Ltd., Flowing Energy Corporation, Petrowest Corporation and Porto Energy Corp. Mr. Romanzin is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta and holds a Bachelor of Commerce degree from the University of Calgary.
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, 2018 and 2017 PricewaterhouseCoopers LLP billed approximately $1,746,288 and $907,324, respectively, as detailed below:

	Year ended December 31	
	2018	2017
PricewaterhouseCoopers		
Audit fees	$ 1,529,983	$ 789,500
Audit-related fees	$ 216,305	$ 21,974
Tax fees	—	—
All other fees	—	$ 95,850
Total (1)	$ 1,746,288	$ 907,324

Note:
(1) The increase in 2018 is due to the timing of when invoices were billed.

The Chairman 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 6, 2019 in respect of the Corporation's consolidated financial statements as at December 31, 2018 and December 31, 2017 and the Corporation's internal control over financial reporting as at December 31, 2018. 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 May 4, 2018, 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, 2018.

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 securityholders 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 securityholders, 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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

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%, included in the reserves data of the Company evaluated for the year ended December 31, 2018, 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, 2018	Canada	—	2,712,227	—	**2,712,227**

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 13, 2019

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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

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%, included in the reserves data of the Company evaluated for the year ended December 31, 2018, 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, 2018	U.S.A.	—	2,957,634	—	**2,957,634**

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 13, 2019

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, 2018. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2018, estimated using forecast prices and costs.

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%, included in the reserves data of the Company evaluated for the year ended December 31, 2018, 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, 2018	Canada				
Total			Nil	10,925,655	Nil	10,925,655

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, 2018)”.

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, 2019

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

Charles Wong, P.Eng.
Petroleum Engineer

Alec Kovaltchouk, P.Geo.
VP, Geoscience

Nora T. Stewart, P.Eng.
Senior VP, Reserves Certification and Director

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"	*"Peter Bannister"*
FRANCOIS LANGLOIS Director	PETER BANNISTER Director

March 6, 2019

Exhibit 99.2

MANAGEMENT'S REPORT

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

The management of Crescent Point Energy Corp. is responsible for the preparation of the consolidated financial statements. The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board and include certain estimates that reflect management's best estimates and judgments. Management has determined such amounts on a reasonable basis in order to determine that the consolidated financial statements are presented fairly in all material respects.

PricewaterhouseCoopers LLP, an independent firm of chartered professional accountants, was appointed by a resolution of the Board of Directors to audit the consolidated financial statements of the Company and to provide an independent professional opinion. PricewaterhouseCoopers LLP was appointed to hold such office until the next annual meeting of the shareholders of the Company.

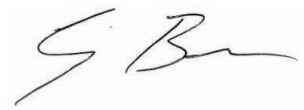
The Board of Directors, through its Audit Committee, has reviewed the consolidated financial statements including notes thereto with management and PricewaterhouseCoopers LLP. The members of the Audit Committee are composed of independent directors who are not employees of the Company. The Audit Committee meets regularly with management and PricewaterhouseCoopers LLP to review and approve the consolidated financial statements. The Board of Directors has approved the information contained in the consolidated financial statements based on the recommendation of the Audit Committee.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management has developed and maintains an extensive system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the consolidated financial statements realistically report the Company's operating and financial results, and that the Company's assets are safeguarded. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

Management has assessed the effectiveness of the Company's internal control over financial reporting as at December 31, 2018. 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, 2018. 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, 2018, has audited the effectiveness of the Company's internal control over financial reporting as at December 31, 2018.



Craig Bryksa
President and Chief Executive Officer



Ken Lamont
Chief Financial Officer

March 6, 2019

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, 2018 and 2017, and the related consolidated statements of comprehensive income, 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, 2018, 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, 2018 and 2017, and their financial performance and their cash flows for the years then ended in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board ("IFRS"). Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report On Internal Controls 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.

PricewaterhouseCoopers LLP

Chartered Professional Accountants
Calgary, Alberta, Canada
March 6, 2019

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

CONSOLIDATED BALANCE SHEETS

As at December 31			
(Cdn$ millions)	Notes	**2018**	2017
ASSETS			
Cash		**15.3**	62.4
Accounts receivable		**322.6**	380.2
Prepaids and deposits		**4.6**	4.5
Derivative asset	25	**244.1**	35.8
Assets held for sale	8, 9	**—**	26.4
Total current assets		**586.6**	509.3
Long-term investments	5	**8.7**	72.6
Derivative asset	25	**351.5**	246.9
Other long-term assets	6	**34.5**	34.5
Exploration and evaluation	7, 8	**472.6**	634.9
Property, plant and equipment	8, 9	**10,430.2**	14,062.4
Goodwill	10	**244.0**	251.9
Deferred income tax		**602.3**	192.8
Total assets		**12,730.4**	16,005.3
LIABILITIES			
Accounts payable and accrued liabilities		**532.9**	613.3
Dividends payable		**16.5**	16.8
Current portion of long-term debt	12	**99.8**	63.8
Derivative liability	25	**—**	107.3
Other current liabilities	11, 23	**39.4**	57.7
Liabilities associated with assets held for sale	14	**—**	4.6
Total current liabilities		**688.6**	863.5
Long-term debt	12	**4,176.9**	4,047.2
Derivative liability	25	**—**	16.6
Other long-term liabilities	13, 23	**48.3**	54.0
Decommissioning liability	14	**1,203.8**	1,310.5
Deferred income tax		**—**	550.6
Total liabilities		**6,117.6**	6,842.4
SHAREHOLDERS' EQUITY			
Shareholders' capital	15	**16,546.9**	16,489.6
Contributed surplus		**41.4**	72.9
Deficit	16	**(10,567.2)**	(7,751.8)
Accumulated other comprehensive income		**591.7**	352.2
Total shareholders' equity		**6,612.8**	9,162.9
Total liabilities and shareholders' equity		**12,730.4**	16,005.3

Commitments (Note 27)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:



Laura A. Cillis
Director



Gerald A. Romanzin
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31 (Cdn$ millions, except per share amounts)	Notes	2018	2017 (Revised)
REVENUE AND OTHER INCOME			
Oil and gas sales	18	**3,887.5**	3,303.9
Purchased product sales		**25.4**	27.0
Royalties		**(592.4)**	(472.2)
Oil and gas revenue		**3,320.5**	2,858.7
Derivative gains (losses)	19, 25	**179.6**	(62.4)
Other income (loss)	5, 20	**(143.5)**	27.8
		3,356.6	2,824.1
EXPENSES			
Operating		**853.8**	807.2
Purchased product		**24.0**	27.8
Transportation		**131.7**	133.8
General and administrative		**121.9**	98.0
Interest on long-term debt		**184.4**	162.3
Foreign exchange (gain) loss	21	**234.0**	(215.7)
Share-based compensation	23	**46.0**	62.0
Depletion, depreciation, amortization and impairment	7, 9	**5,284.7**	1,741.4
Accretion	13, 14	**31.5**	30.9
		6,912.0	2,847.7
Net income (loss) before tax		**(3,555.4)**	(23.6)
Tax expense (recovery)			
Current	22	**0.3**	(1.7)
Deferred	22	**(938.8)**	102.1
Net income (loss)		**(2,616.9)**	(124.0)
Other comprehensive income (loss)			
Items that may be subsequently reclassified to profit or loss			
Foreign currency translation of foreign operations		**239.5**	(160.3)
Comprehensive income (loss)		**(2,377.4)**	(284.3)
Net income (loss) per share	24		
Basic		**(4.77)**	(0.23)
Diluted		**(4.77)**	(0.23)

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, 2017		**16,489.6**	**72.9**	**(7,751.8)**	**352.2**	**9,162.9**
Redemption of restricted shares	15	**57.3**	**(59.0)**			**(1.7)**
Share-based compensation	23		**35.1**			**35.1**
Forfeit of restricted shares	23		**(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**
December 31, 2016		16,400.2	110.6	(7,432.1)	512.5	9,591.2
Redemption of restricted shares		89.6	(91.9)	2.0		(0.3)
Share issue costs, net of tax		(0.2)				(0.2)
Share-based compensation			62.1			62.1
Forfeit of restricted shares			(7.9)			(7.9)
Net income (loss)				(124.0)		(124.0)
Dividends ($0.36 per share)				(197.7)		(197.7)
Foreign currency translation adjustment					(160.3)	(160.3)
December 31, 2017		16,489.6	72.9	(7,751.8)	352.2	9,162.9

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31			
(Cdn$ millions)	Notes	**2018**	2017
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES			
Net income (loss)		**(2,616.9)**	(124.0)
Items not affecting cash			
Other (income) loss	5, 20	**143.5**	(27.8)
Deferred tax expense (recovery)	22	**(938.8)**	102.1
Share-based compensation	23	**19.8**	42.2
Depletion, depreciation, amortization and impairment	7, 9	**5,284.7**	1,741.4
Accretion	13, 14	**31.5**	30.9
Unrealized (gains) losses on derivatives	19, 25	**(439.4)**	163.6
Translation of US dollar long-term debt	21	**324.5**	(255.8)
Other	29	**(2.5)**	(2.1)
Realized (gain) loss on cross currency swap maturity	21	**(70.3)**	54.6
Decommissioning expenditures		**(25.3)**	(25.1)
Change in non-cash working capital	29	**37.2**	18.7
		1,748.0	1,718.7
INVESTING ACTIVITIES			
Development capital and other expenditures	7, 9	**(1,817.8)**	(1,854.7)
Capital acquisitions, net	8	**(15.4)**	(308.1)
Capital dispositions	8	**243.3**	266.1
Other long-term assets	6	**—**	2.2
Long-term investments	5	**162.1**	0.1
Change in non-cash working capital	29	**(81.6)**	(65.8)
		(1,509.4)	(1,960.2)
FINANCING ACTIVITIES	29		
Issue of shares, net of issue costs		**(1.7)**	(2.6)
Increase (decrease) in bank debt, net		**(360.0)**	635.9
Issuance of senior guaranteed notes		**267.3**	—
Repayment of senior guaranteed notes		**(65.0)**	(90.3)
Realized gain (loss) on cross currency swap maturity	21	**70.3**	(54.6)
Cash dividends		**(198.5)**	(197.7)
Change in non-cash working capital	29	**(0.3)**	0.5
		(287.9)	291.2
Impact of foreign currency on cash balances		**2.2**	(0.7)
INCREASE (DECREASE) IN CASH		**(47.1)**	49.0
CASH AT BEGINNING OF YEAR		**62.4**	13.4
CASH AT END OF YEAR		**15.3**	62.4

See accompanying notes to the consolidated financial statements.

Supplementary Information:

Cash taxes paid	**—**	(0.3)
Cash interest paid	**(177.1)**	(159.2)

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 6, 2019.

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 6, 2019, 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 spending on the project requires unanimous consent of all parties that collectively control the arrangement 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 costs accumulated within major areas 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 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, adjusted for 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.

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.

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, adjusted for the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves as described in the PP&E impairment test. 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) Reclamation Fund

The Company established a voluntary reclamation fund to fund future decommissioning costs and environmental initiatives. Effective January 1, 2018, the Board of Directors approved contributions of $0.40 per barrel of oil equivalent of production. There were contributions to the fund of $27.6 million during 2018. Additional contributions can be made at the discretion of management.

f) 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, adjusted for the discounted abandonment and reclamation costs on proved plus probable undeveloped oil and gas reserves as described in the PP&E impairment test, E&E assets and goodwill and comparing this to the recoverable amount. 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. Any excess of the carrying amount over the recoverable amount is the impairment amount. 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.

g) 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.

h) 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.

i) 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.

Prior to January 1, 2018, the Company recorded the financial asset at carrying value with any expected loss provided for through the use of an allowance account.

j) 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.

k) 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 the average exchange rate 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 the average exchange rate 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.

l) 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.

Prior to January 1, 2018, the Company recorded oil and gas revenue for the sale of crude oil, natural gas and natural gas liquids when the risks and rewards of ownership had been substantially transferred.

m) Cash and Cash Equivalents

Cash and cash equivalents include short-term investments with original maturities of three months or less.

n) Leases

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.

All of the Company's current leases are treated as operating leases and are recognized in net income on a straight-line basis.

o) 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.

p) Assets Held for Sale

PP&E and E&E assets are classified as held for sale if it is highly probable their carrying amounts will be recovered through a capital disposition rather than through future operating cash flows. Before PP&E and E&E assets are classified as held for sale, they are assessed for indicators of impairment or reversal of previously recorded impairments and are measured at the lower of their carrying amount and fair value less costs of disposal. Any impairment charges or 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

In the current accounting period, the Company adopted the July 2014 amendment to IFRS 9 *Financial Instruments* and IFRS 15 *Revenue from Contracts with Customers*. On January 1, 2019, the Company will adopt IFRS 16 *Leases*.

IFRS 9 *Financial Instruments*

On January 1, 2018, the Company adopted the July 2014 amendment to IFRS 9, which included guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The adoption of this amendment did not have a material impact on the valuation of the Company's financial assets. Comparative periods have not been restated as the Company has elected to apply the limited exemption on transition.

The Company had previously early adopted IFRS 9 with a date of initial application of January 1, 2010 and the amendment to IFRS 9 which presented a new hedge accounting model.

IFRS 15 *Revenue from Contracts with Customers*

On January 1, 2018, the Company adopted IFRS 15 using the modified retrospective approach. The Company elected to use the following practical expedients:

- IFRS 15 was only applied retrospectively to contracts which were not completed as at January 1, 2018; and
- Modifications to any existing contracts will be assessed in aggregate with the original contract at the original date.

The Company reviewed contracts with customers for its major revenue streams and concluded that the adoption of IFRS 15 did not have a material impact on the consolidated financial statements. The adoption of IFRS 15 required the Company to expand its disclosures in the notes to the consolidated financial statements, including the disaggregation of revenue streams by product type.

As part of the review of contracts for compliance with IFRS 15, the Company performed a review of the presentation of its revenue transactions. The cost of purchases from third parties to fulfill the Company's sales commitments is presented as purchased product expense. The subsequent sales of these commodity products to customers is presented as purchased product sales. Previously, these transactions were presented on a net basis in oil and gas sales. The following table summarizes the amounts revised in the

consolidated statements of comprehensive income for the year ended December 31, 2017:

($ millions)	2017
Oil and gas sales - previously reported	3,303.1
Purchased product sales	(27.0)
Purchased product	27.8
Oil and gas sales - revised	3,303.9

IFRS *16 Leases*

IFRS 16 was issued January 2016 and replaces IAS 17*Leases* and IFRIC 4 *Determining Whether an Arrangement Contains a Lease* The standard introduces a single lessee accounting model for leases with required recognition of assets and liabilities for most leases, where the Company is acting as a lessee. The adoption of IFRS 16 for lessees eliminates the dual classification model of leases as either operating leases or finance leases, effectively treating almost all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from recognition and will continue to be treated as operating leases. There is no significant impact from the adoption of IFRS 16 for lessors as the dual classification model of leases and the accounting for lessors remains virtually unchanged. The standard is effective for fiscal years beginning on or after January 1, 2019 with early adoption permitted if the Company is also applying IFRS 15. The standard is required to be adopted either retrospectively or using a modified retrospective approach.

On January 1, 2019, the Company adopted IFRS 16 using the modified retrospective approach. 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 for onerous contracts instead of re-assessing the ROU asset for impairment on January 1, 2019.

The Company has completed a detailed assessment on the impact of the standard on the consolidated financial statements. A number of leases have been identified with the most significant impact being the recognition of lease obligations on operating leases for office space and the corresponding ROU assets. 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 will record accretion expense on the lease liability and depreciation expense on the ROU asset and the associated ROU asset will be 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.

Adoption of the new standard will result in the recognition of lease liabilities of approximately $220.0 million.

5. LONG-TERM INVESTMENTS

($ millions)	2018	2017
Investments in public companies, beginning of year	**65.1**	28.3
Acquired through capital dispositions	**112.6**	40.2
Dispositions	**(152.8)**	—
Unrealized loss recognized in other income (loss)	**(16.2)**	(3.4)
Investments in public companies, end of year	**8.7**	65.1
Investment in private company, beginning of year	**7.5**	7.5
Dispositions	**(7.5)**	—
Investment in private company, end of year	**—**	7.5
Long-term investments, end of year	**8.7**	72.6

a) 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, 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. At December 31, 2017, the investments were recorded at a fair value of $65.1 million which was $14.4 million more than the original cost of the investments.

b) Private company

During the year ended December 31, 2018, the Company disposed of its common shares in a private oil and gas company. The investment was classified as financial assets at fair value through profit or loss and was fair valued at each period with the resulting gain or loss recorded in net income. At December 31, 2017, the investment was recorded at a fair value of $7.5 million which was $17.5 million less than the original cost of the investment.

6. OTHER LONG-TERM ASSETS

($ millions)	2018	2017
Reclamation fund	**18.7**	18.7
Other receivables	**15.8**	15.8
Other long-term assets	**34.5**	34.5

a) Reclamation fund

The following table reconciles the reclamation fund:

($ millions)	2018	2017
Balance, beginning of year	**18.7**	22.7
Contributions	**27.6**	22.5
Expenditures	**(27.6)**	(26.5)
Balance, end of year	**18.7**	18.7

b) Other receivables

At December 31, 2018, the Company had investment tax credits of$15.8 million (December 31, 2017 - $15.8 million).

7. EXPLORATION AND EVALUATION ASSETS

($ millions)	**2018**	2017
Exploration and evaluation assets at cost	**2,325.0**	2,305.1
Accumulated amortization	**(1,852.4)**	(1,670.2)
Net carrying amount	**472.6**	634.9
Reconciliation of movements during the year		
Cost, beginning of year	**2,305.1**	2,080.7
Accumulated amortization, beginning of year	**(1,670.2)**	(1,582.6)
Net carrying amount, beginning of year	**634.9**	498.1
Net carrying amount, beginning of year	**634.9**	498.1
Acquisitions through business combinations, net	**10.2**	116.9
Additions	**673.3**	729.1
Dispositions	**(7.5)**	(12.9)
Transfers to property, plant and equipment	**(705.9)**	(541.4)
Amortization	**(157.2)**	(134.3)
Foreign exchange	**24.8**	(20.6)
Net carrying amount, end of year	**472.6**	634.9

Exploration and evaluation ("E&E") assets consist of the Company's undeveloped land and exploration projects which are pending the determination of technical feasibility. At December 31, 2018, $472.6 million remained in E&E assets after $705.9 million was transferred to property, plant and equipment ("PP&E") following the determination of technical feasibility during the year ended December 31, 2018 (year ended December 31, 2017 - $634.9 million and $541.4 million, respectively).

Impairment test of exploration and evaluation assets

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 testing was required and the Company prepared estimates of future cash flows and fair market values of undeveloped land to determine the recoverable amount of the respective assets. As a result of these tests, the Company concluded that the estimated recoverable amounts exceeded the carrying amounts and no impairments were recorded.

8. CAPITAL ACQUISITIONS AND DISPOSITIONS

In the year ended December 31, 2018, the Company incurred $5.1 million (year ended December 31, 2017 - $3.7 million) of transaction costs related to acquisitions through business combinations and dispositions that were recorded as general and administrative expenses.

a) Major Property Disposition

Southeast Saskatchewan asset disposition

In the year ended December 31, 2018, the Company completed the disposition of non-core assets in southeast Saskatchewan and southwest Manitoba for total proceeds of $213.4 million. This disposition was completed with full tax pools and no working capital items.

($ millions)	
Exploration and evaluation	(2.4)
Property, plant and equipment	(288.7)
Goodwill	(6.2)
Decommissioning liability	26.8
	(270.5)
Proceeds	
Cash	112.5
Long-term investments	100.9
	213.4
Loss on capital dispositions	(57.1)

b) Minor property acquisitions and dispositions

In the year ended December 31, 2018, the Company completed minor property acquisitions and dispositions including assets and associated liabilities held for sale at December 31, 2017 for total proceeds received of $127.1 million. These minor property acquisitions and dispositions were completed with full tax pools and no working capital items.

($ millions)	
Acquisitions	
Exploration and evaluation	10.2
Property, plant and equipment	12.2
Decommissioning liability	(0.4)
	22.0
Dispositions	
Exploration and evaluation	(5.1)
Property, plant and equipment [(1)]	(261.5)
Goodwill	(0.6)
Decommissioning liability [(1)]	46.1
	(221.1)
Proceeds received, net	
Cash	115.4
Long-term investments	11.7
	127.1
Loss on capital dispositions	(72.0)

(1) Includes assets and associated liabilities classified as held for sale at December 31, 2017.

9. PROPERTY, PLANT AND EQUIPMENT

($ millions)	2018	2017
Development and production assets	**26,635.3**	25,881.1
Corporate assets	**114.6**	106.4
Property, plant and equipment at cost	**26,749.9**	25,987.5
Accumulated depletion, depreciation and impairment	**(16,319.7)**	(11,925.1)
Net carrying amount	**10,430.2**	14,062.4
Reconciliation of movements during the year		
Development and production assets		
Cost, beginning of year	**25,881.1**	24,846.9
Accumulated depletion and impairment, beginning of year	**(11,877.1)**	(10,735.5)
Net carrying amount, beginning of year	**14,004.0**	14,111.4
Net carrying amount, beginning of year	**14,004.0**	14,111.4
Acquisitions through business combinations, net	**12.2**	220.2
Additions	**1,083.6**	1,211.8
Dispositions, net	**(523.8)**	(332.7)
Transfers from exploration and evaluation assets	**705.9**	541.4
Reclassified as assets held for sale	**—**	(26.4)
Depletion	**(1,412.4)**	(1,394.4)
Impairment	**(3,704.8)**	(203.6)
Foreign exchange	**208.4**	(123.7)
Net carrying amount, end of year	**10,373.1**	14,004.0
Cost, end of year	**26,635.3**	25,881.1
Accumulated depletion and impairment, end of year	**(16,262.2)**	(11,877.1)
Net carrying amount, end of year	**10,373.1**	14,004.0
Corporate assets		
Cost, beginning of year	**106.4**	102.4
Accumulated depreciation, beginning of year	**(48.0)**	(38.9)
Net carrying amount, beginning of year	**58.4**	63.5
Net carrying amount, beginning of year	**58.4**	63.5
Additions	**7.7**	4.2
Depreciation	**(9.2)**	(9.1)
Foreign exchange	**0.2**	(0.2)
Net carrying amount, end of year	**57.1**	58.4
Cost, end of year	**114.6**	106.4
Accumulated depreciation, end of year	**(57.5)**	(48.0)
Net carrying amount, end of year	**57.1**	58.4

At December 31, 2018, future development costs of $7.23 billion (December 31, 2017 - $7.00 billion) were included in costs subject to depletion.

Direct general and administrative costs capitalized by the Company during the year ended December 31, 2018 were $48.0 million (year ended December 31, 2017 - $50.4 million), including $7.7 million of share-based compensation costs (year ended December 31, 2017 - $12.0 million).

Impairment test of property, plant and equipment

For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment or its reversal, management exercises their judgment in estimating future cash flows for the recoverable amount, being the higher of fair value less costs of disposal and value in use. These key judgments include estimates about recoverable reserves, forecast benchmark commodity prices, royalties, operating costs, capital costs and discount rates. 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.

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 [3]
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 the higher industry weighted average cost of capital at December 31, 2018 compared to December 31, 2017 and current economic factors. The increased industry weighted average cost of capital is the result of increased volatility in the Canadian energy sector due to limited crude oil market access and the current regulatory environment, causing industry participants to have limited access to new capital.

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)

2017 Impairment and recovery

For the year ended December 31, 2017, the decrease in near-term forecast benchmark commodity prices as compared to December 31, 2016 and the value of the Company's market capitalization as compared to net asset value were indicators of impairment. In addition, the significant changes to U.S. tax legislation in December 2017 including, among other things, a significant decrease to the federal corporate income tax rate, was an indicator of recovery in the U.S. operating segment. 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, 2017:

	2018	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028** [(2)]
WTI ($US/bbl) [(1)]	55.00	65.00	70.00	73.00	74.46	75.95	77.47	79.02	80.60	82.21	83.85
Exchange Rate ($US/$Cdn)	0.790	0.820	0.850	0.850	0.850	0.850	0.850	0.850	0.850	0.850	0.850
WTI ($Cdn/bbl)	69.62	79.27	82.35	85.88	87.60	89.35	91.14	92.96	94.82	96.72	98.65
AECO ($Cdn/MMbtu) [(1)]	2.85	3.11	3.65	3.80	3.95	4.05	4.15	4.25	4.36	4.46	4.57

(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 2028 to the end of the reserve life. Exchange rates are assumed to be constant at 0.850.

At December 31, 2017, the Company determined that the carrying amount of the Southeast Saskatchewan, Southwest Saskatchewan and Southern Alberta CGUs exceeded their recoverable amount. In addition, the recoverable amount of the Northern U.S. and Utah CGUs exceeded their carrying amount. The full amount of the impairments and recoveries were attributed to PP&E and, as a result, net impairment losses of $203.6 million were recorded as a component of depletion, depreciation, amortization and impairment expense.

The following table summarizes the impairment and recovery for the year ended December 31, 2017 by CGU:

CGU ($ millions, except %)	**Operating segment**	**Recoverable amount**	**Discount rate**	**(Impairment) / Recovery**	**(Impairment) / Recovery, net of tax**
Southeast Saskatchewan	Canada	6,946.2	10.25%	(281.7)	(206.1)
Southwest Saskatchewan	Canada	2,412.6	10.25%	(164.1)	(120.0)
Southern Alberta	Canada	1,217.9	11.00%	(109.6)	(80.2)
Northern U.S.	U.S.	976.5	10.50%	87.9	54.6
Utah	U.S.	1,482.4	10.25%	263.9	164.0
Total impairment		13,035.6		(203.6)	(187.7)

The impairments in the Southeast Saskatchewan, Southwest Saskatchewan and Southern Alberta CGUs were largely a result of the decrease in near-term forecast benchmark commodity prices and the increase in discount rates, partially offset by the positive impact of technical and development reserve additions. The recoveries in the Northern U.S. and Utah CGUs were largely a result of the positive impact of technical and development reserve additions and the positive impact of the changes to U.S. tax legislation, partially offset by the decrease in near-term forecast benchmark commodity prices and the increase in discount rates.

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, 2017, with all other variables held constant:

CGU	Discount Rate		Commodity Prices	
($ millions)	Increase 1%	Decrease 1%	Increase 5%	Decrease 5%
Southeast Saskatchewan	(559.4)	627.7	831.9	(839.6)
Southwest Saskatchewan	(209.6)	235.6	306.0	(305.7)
Southern Alberta	(114.3)	128.1	176.7	(175.8)
Northern U.S.	—	—	—	—
Utah	(103.6)	116.4	174.9	(173.6)
Increase (decrease)	(986.9)	1,107.8	1,489.5	(1,494.7)

10. GOODWILL

($ millions)	**2018**	2017
Goodwill, beginning of year	**251.9**	251.9
Southeast Saskatchewan asset disposition	**(6.2)**	—
Minor property dispositions	**(0.6)**	—
Transferred to assets held for sale [(1)]	**(1.1)**	—
Goodwill, end of year	**244.0**	251.9

(1) At September 30, 2018, the Company classified certain non-core assets in the Canadian operating segment 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 $1.1 million related to goodwill. These assets have been disposed of prior to December 31, 2018.

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, 2018 and December 31, 2017. As a result of these tests, the Company concluded that the estimated recoverable amounts exceeded the carrying amounts and no impairments were recorded. The recoverable amount estimates is categorized as Level 3 according to the IFRS 13 fair value hierarchy. Refer to Note 9 - "Property, Plant and Equipment" for a description of the key input estimates and the methodology used in the determination of the estimated recoverable amount related to goodwill.

11. OTHER CURRENT LIABILITIES

($ millions)	**2018**	2017
Long-term compensation liability	**6.5**	17.7
Lease inducement	**3.4**	3.4
Onerous contracts provision	**2.6**	2.9
Decommissioning liability	**26.9**	33.7
Other current liabilities	**39.4**	57.7

12. LONG-TERM DEBT

The following table reconciles long-term debt:

($ millions)	**2018**	2017
Bank debt	**1,982.1**	2,179.0
Senior guaranteed notes [(1)]	**2,294.6**	1,932.0
Long-term debt	**4,276.7**	4,111.0
Long-term debt due within one year	**99.8**	63.8
Long-term debt due beyond one year	**4,176.9**	4,047.2

(1) The Company entered into cross currency swaps 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, 2018, the total notional principal due on the maturity of the senior guaranteed notes was $1.89 billion (December 31, 2017 - $1.67 billion) of which $73.7 million (December 31, 2017 - $50.3 million) was due within one year.

Bank debt

The Company has combined credit facilities of $3.60 billion, including a $3.50 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 date of the syndicated unsecured credit facility and the unsecured operating credit facility is June 10, 2021. 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 certain non-cash items including unrealized derivatives, unrealized foreign exchange, equity settled share-based compensation expense and accretion ("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, 2018.

The Company had letters of credit in the amount of $8.0 million outstanding at December 31, 2018 (December 31, 2017 - $7.5 million).

The Company manages its credit facilities through a combination of bankers' acceptance loans, US dollar London Inter-bank Offered Rate ("LIBOR") loans and interest rate swaps.

Senior guaranteed notes

The Company has closed private offerings of senior guaranteed notes raising total gross proceeds of US$1.48 billion and Cdn$277.0 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 terms, rates, amounts due on maturity and carrying amounts of the Company's outstanding 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	
					2018	2017
US$31.0	4.58%	—	October 14 and April 14	April 14, 2018	**—**	38.8
US$20.0	2.65%	—	December 12 and June 12	June 12, 2018	**—**	25.0
Cdn$7.0	4.29%	7.0	November 22 and May 22	May 22, 2019	**7.0**	7.0
US$68.0	3.39%	66.7	November 22 and May 22	May 22, 2019	**92.8**	85.1
US$155.0	6.03%	158.3	September 24 and March 24	March 24, 2020	**211.5**	194.0
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	**111.9**	102.7
US$52.5	3.29%	56.3	December 20 and June 20	June 20, 2021	**71.6**	65.7
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	**272.9**	250.4
US$61.5	4.12%	80.3	October 11 and April 11	April 11, 2023	**83.9**	—
Cdn$80.0	3.58%	80.0	October 11 and April 11	April 11, 2023	**80.0**	—
Cdn$10.0	4.11%	10.0	December 12 and June 12	June 12, 2023	**10.0**	10.0
US$270.0	3.78%	274.7	December 12 and June 12	June 12, 2023	**368.4**	338.0
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	**351.4**	322.4
US$82.0	4.30%	107.0	October 11 and April 11	April 11, 2025	**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	**313.9**	287.9
US$20.0	4.18%	25.3	October 22 and April 22	April 22, 2027	**27.4**	25.0
Senior guaranteed notes		1,891.2			**2,294.6**	1,932.0
Senior guaranteed notes due within one year					**99.8**	63.8
Senior guaranteed notes due beyond one year					**2,194.8**	1,868.2

(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$1.45 billion senior guaranteed notes, the Company entered into cross currency swaps ("CCS") to manage the Company's foreign exchange risk. The CCS fix the US dollar amount of the notes for purposes of interest and principal repayments at a notional amount of $1.58 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 25 - “Financial Instruments and Derivatives” for additional information.

13. OTHER LONG-TERM LIABILITIES

($ millions)	**2018**	2017
Long-term compensation liability [1]	**3.5**	5.2
Lease inducement [2]	**36.4**	40.0
Onerous contracts provision [3] [4]	**8.4**	8.8
Other long-term liabilities	**48.3**	54.0

(1) Long-term compensation liability relates to share-based compensation. See Note 23 - "Share-based Compensation" for additional information.

(2) The Company's lease inducement is associated with the building lease for Crescent Point's corporate office. This non-cash liability is amortized on a straight-line basis over the term of the lease to June 2030.

(3) Onerous contracts provision is related to the estimated unrecoverable portion of building leases.

(4) For the year ended December 31, 2018, the Company recorded $0.9 million of accretion expense related to the onerous contract provision (year ended December 31, 2017 - $0.6 million).

14. DECOMMISSIONING LIABILITY

The following table reconciles the decommissioning liability:

($ millions)	**2018**	2017
Decommissioning liability, beginning of year	**1,344.2**	1,314.4
Liabilities incurred	**38.6**	39.9
Liabilities acquired through capital acquisitions	**0.4**	25.1
Liabilities disposed through capital dispositions	**(68.3)**	(66.5)
Liabilities settled	**(25.3)**	(25.1)
Revaluation of acquired decommissioning liabilities [1]	**0.6**	42.8
Change in estimated future costs	**(79.9)**	2.8
Change in discount rate	**(20.2)**	(7.2)
Accretion expense	**30.6**	30.3
Reclassified as liabilities associated with assets held for sale	**—**	(4.6)
Foreign exchange	**10.0**	(7.7)
Decommissioning liability, end of year	**1,230.7**	1,344.2
Expected to be incurred within one year	**26.9**	33.7
Expected to be incurred beyond one year	**1,203.8**	1,310.5

(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 $1.23 billion at December 31, 2018 (December 31, 2017 - $1.34 billion) based on total estimated undiscounted cash flows to settle the obligation of $1.29 billion (December 31, 2017 - $1.41 billion). These obligations are expected to be settled through 2053, with the majority expected after 2039. The estimated cash flows have been discounted using a risk free rate of approximately 2.25 percent and an inflation rate of 2 percent (December 31, 2017 - approximately 2.25 percent and 2 percent, respectively).

15. SHAREHOLDERS' CAPITAL

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

	2018		2017	
	Number of shares	**Amount ($ millions)**	Number of shares	Amount ($ millions)
Common shares, beginning of year	**545,794,384**	**16,745.7**	541,742,592	16,656.1
Issued on redemption of restricted shares [1]	**4,357,177**	**57.3**	4,051,792	89.6
Common shares, end of year	**550,151,561**	**16,803.0**	545,794,384	16,745.7
Cumulative share issue costs, net of tax	**—**	**(256.1)**	—	(256.1)
Total shareholders' capital, end of year	**550,151,561**	**16,546.9**	545,794,384	16,489.6

(1) The amount of shares issued on redemption of restricted shares is net of employee withholding taxes.

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 is due to expire on January 24, 2020.

As of the date of this report, the Company has purchased, for cancellation,1,284,400 common shares for total consideration of$5.0 million.

16. DEFICIT

($ millions)	**2018**	2017
Accumulated earnings (deficit)	**(2,980.6)**	(363.7)
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	**(7,607.1)**	(7,408.6)
Deficit	**(10,567.2)**	(7,751.8)

(1) Premium Dividend ™ and Dividend Reinvestment Plan.

(2) Share Dividend Plan.

17. CAPITAL MANAGEMENT

The Company's capital structure is comprised of shareholders' equity, long-term debt and adjusted working capital. The balance of each of these items is as follows:

($ millions)	**2018**	2017
Long-term debt	**4,276.7**	4,111.0
Adjusted working capital deficiency [1]	**208.2**	133.3
Unrealized foreign exchange on translation of US dollar long-term debt	**(473.6)**	(219.4)
Net debt	**4,011.3**	4,024.9
Shareholders' equity	**6,612.8**	9,162.9
Total capitalization	**10,624.1**	13,187.8

(1) Adjusted working capital deficiency is calculated as accounts payable and accrued liabilities, dividends payable 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, 2018 and December 31, 2017:

($ millions)	**2018**	2017
Cash flow from operating activities	**1,748.0**	1,718.7
Changes in non-cash working capital	**(37.2)**	(18.7)
Transaction costs	**5.1**	3.7
Decommissioning expenditures	**25.3**	25.1
Adjusted funds flow from operations	**1,741.2**	1,728.8

Crescent Point's objective for managing capital 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 is calculated as long-term debt plus accounts payable and accrued liabilities, dividends payable 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. Adjusted funds flow from operations is calculated as cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. 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, 2018 was 2.3 times (December 31, 2017 - 2.3 times).

Crescent Point strives to fund its capital expenditures, decommissioning expenditures and dividends over time by managing risks associated with the oil and gas industry. To accomplish this, the Company aims to maintain a conservative balance sheet with significant liquidity and unutilized lines of credit, manages its exposure to fluctuating interest rates and foreign exchange rates on its long-term debt, and actively hedges commodity prices through its risk management program. See Note 25 - "Financial Instruments and Derivatives" for additional information regarding the Company's derivative contracts.

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, 2018. See Note 12 - "Long-term Debt" for additional information regarding the Company's financial covenant requirements.

18. OIL AND GAS SALES

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

($ millions) [1]	**2018**	2017
Canada		
Crude oil sales	**2,743.6**	2,581.9
NGL sales	**202.1**	158.2
Natural gas sales	**54.3**	70.6
Total Canada	**3,000.0**	2,810.7
U.S.		
Crude oil sales	**811.7**	435.3
NGL sales	**41.2**	27.0
Natural gas sales	**34.6**	30.9
Total U.S.	**887.5**	493.2
Total oil and gas sales	**3,887.5**	3,303.9

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

19. DERIVATIVE GAINS (LOSSES)

($ millions)	**2018**	2017
Realized gains (losses)	**(259.8)**	101.2
Unrealized gains (losses)	**439.4**	(163.6)
Derivative gains (losses)	**179.6**	(62.4)

20. OTHER INCOME (LOSS)

($ millions)	**2018**	2017
Long-term investments	**(15.5)**	(3.4)
Gain (loss) on capital dispositions	**(129.1)**	31.1
Dividend income	**1.1**	—
Other gain	**—**	0.1
Other income (loss)	**(143.5)**	27.8

21. FOREIGN EXCHANGE GAIN (LOSS)

($ millions)	2018	2017
Realized gain (loss)		
CCS - US dollar long-term debt maturities and interest payments	**88.3**	(39.3)
US dollar long-term debt maturities	**(70.3)**	54.6
Other	**4.3**	(0.6)
Unrealized gain (loss)		
Translation of US dollar long-term debt	**(254.2)**	201.2
Other	**(2.1)**	(0.2)
Foreign exchange gain (loss)	**(234.0)**	215.7

22. INCOME TAXES

The provision for income taxes is as follows:

($ millions)	2018	2017
Current tax:		
Canada	**—**	(1.9)
Luxembourg	**0.3**	0.2
Current tax expense (recovery)	**0.3**	(1.7)
Deferred tax:		
Canada	**(690.5)**	(99.2)
United States	**(248.3)**	201.3
Deferred tax expense (recovery)	**(938.8)**	102.1
Income tax expense (recovery)	**(938.5)**	100.4

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

($ millions)	2018	2017
Net income (loss) before tax	**(3,555.4)**	(23.6)
Statutory income tax rate	**27.00%**	26.85%
Expected provision for income taxes	**(960.0)**	(6.3)
Effect of change in corporate tax rates	**—**	106.9
Effect of tax rates in foreign jurisdictions	**13.9**	22.9
Effect of restricted share bonus plan	**1.8**	(2.7)
Effect of change in recognition of deferred tax assets	**(1.1)**	(14.7)
Effect of non-taxable capital (gains) losses	**0.6**	(1.1)
Non-deductible disposition of goodwill	**2.1**	—
Other	**4.2**	(4.6)
Income tax recovery	**(938.5)**	100.4

The statutory combined federal and provincial income tax rate decreased from 27.00% in 2016 to 26.85% in 2017 primarily due to the decrease in the Saskatchewan corporate tax rate from 12.00% to 11.50%, effective July 1, 2017. The Saskatchewan corporate tax rate was subsequently changed back to 12.00% effective January 1, 2018, resulting in an increase in the combined federal and provincial income tax rate from 26.85% in 2017 to 27.00% in 2018.

On December 22, 2017, the United States government enacted the Tax Cuts and Jobs Act which implemented significant changes to the U.S. tax legislation including, among other changes, a decrease to the federal corporate income tax rate from 35% to 21% effective January 1, 2018. As a result, the Company reduced its deferred income tax asset by $107.5 million at December 31, 2017 and recognized a corresponding deferred income tax expense.

The composition of net deferred income tax asset (liability) is as follows:

($ millions)	**2018**	2017
Deferred income tax assets	**602.3**	192.8
Deferred income tax liabilities	**—**	(550.6)
Net deferred income tax assets (liabilities)	**602.3**	(357.8)

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

($ millions)	**2018**	2017
Deferred income tax:		
To be settled within one year	**(57.9)**	29.1
To be settled beyond one year	**660.2**	(386.9)
Deferred income tax	**602.3**	(357.8)

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

($ 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**
Debt financing costs	—	—	—	**—**
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**

($ millions)	At January 1, 2017	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	At December 31, 2017
Deferred income tax assets:				
Decommissioning liability	361.8	—	(0.5)	361.3
Income tax losses carried forward	632.4	—	17.1	649.5
Debt financing costs	4.8	—	(4.8)	—
Share issue costs	15.3	0.1	(5.2)	10.2
Risk management contracts	18.3	—	15.2	33.5
Other	16.6	(26.7)	32.3	22.2
	1,049.2	(26.6)	54.1	1,076.7
Deferred income tax liabilities:				
Property, plant and equipment	(1,286.7)	—	(130.8)	(1,417.5)
Risk management contracts	8.4	—	(25.4)	(17.0)
	(1,278.3)	—	(156.2)	(1,434.5)
Net deferred income tax liabilities	(229.1)	(26.6)	(102.1)	(357.8)

The approximate amounts of tax pools available as at December 31, 2018 and 2017 are as follows:

($ millions)	**2018**	2017
Tax pools:		
Canada	**8,389.0**	8,746.2
United States	**3,830.0**	3,287.6
Total	**12,219.0**	12,033.8

Deferred income tax assets have been recognized in both Canada and the U.S. as it is probable given the Company's anticipated future earnings that the tax pools will be utilized in the future against future profits. The above tax pools include estimated Canadian non-capital losses carried forward of $1.90 billion (December 31, 2017 - $1.40 billion) that expire in the years 2026 through 2038, and U.S. net operating losses of $1.73 billion (December 31, 2017 - $1.20 billion) which expire in the years 2024 through 2037. A deferred income tax asset has not been recognized for U.S. net operating losses of $89.7 million (December 31, 2017 - $82.3 million) or for other temporary differences of $56.2 million (December 31, 2017 - $33.2 million) as there is not sufficient certainty regarding future utilization.

At December 31, 2017, a deferred tax asset has not been recognized in respect of certain unrealized capital losses and capital losses carried forward for Canadian tax purposes in the amount of $1.2 million. Recognition is dependent on the realization of future taxable capital gains.

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 $1.3 billion (December 31, 2017 - $555.2 million).

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, 2018 and December 31, 2017.

23. 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 Performance Share Unit ("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 Deferred Share Unit ("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, 2018:

	Restricted Shares	Performance Share Units [(1)]	Deferred Share Units
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.

The following table reconciles the number of restricted shares, PSUs and DSUs for the year ended December 31, 2017:

	Restricted Shares	Performance Share Units [1]	Deferred Share Units
Balance, beginning of year	5,188,358	—	204,653
Granted	3,424,610	4,460,046	70,609
Redeemed	(4,195,754)	—	(45,792)
Forfeited	(235,162)	—	—
Modified to PSUs	(593,028)	—	—
Balance, end of year	3,589,024	4,460,046	229,470

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

Stock Option Plan

In May 2018, the Company approved 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 table reconciles the number of stock options and the related weighted average exercise prices for the year ended December 31, 2018:

	Stock Options (number of units)	Weighted average exercise price ($)
Balance, beginning of year	—	—
Granted	3,158,490	10.04
Exercised	—	—
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, 2018:

Number of stock options outstanding	Weighted average exercise price per share for options outstanding ($)	Vest year	Weighted average remaining term (years)	Number of stock options exercisable	Weighted average exercise price per share for options exercisable ($)
621,323	10.04	2019	6.03	—	—
356,698	10.02	2020	6.05	—	—
356,698	10.02	2021	6.05	—	—
713,396	10.02	2022	6.05	—	—

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:

	2018	2017
Grant date share price ($)	**10.04**	—
Exercise price ($)	**10.04**	—
Expected annual dividends ($)	**0.36**	—
Expected volatility (%)	**35.9%**	—
Risk-free interest rate (%)	**2.00%**	—
Expected life of stock option	**4.9 years**	—
Fair value per stock option ($)	**2.34**	—

For the year ended December 31, 2018, the Company calculated total share-based compensation of $53.7 million (year ended December 31, 2017 - $74.0 million), net of estimated forfeitures, of which $7.7 million was capitalized (year ended December 31, 2017 - $12.0 million).

At December 31, 2018, the current portion of long-term compensation liability of $6.5 million was included in other current liabilities (December 31, 2017 - $17.7 million) and $3.5 million was included in other long-term liabilities (December 31, 2017 - $5.2 million).

24. PER SHARE AMOUNTS

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

	2018	2017
Weighted average shares – basic	**549,109,960**	545,162,580
Dilutive impact of share-based compensation	**—**	—
Weighted average shares – diluted [1]	**549,109,960**	545,162,580

(1) Excludes the impact of 1,086,922 weighted average shares related to share-based compensation that were anti-dilutive for the year ended December 31, 2018 (year ended December 31, 2017 - 1,603,575).

25. FINANCIAL INSTRUMENTS AND DERIVATIVES

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

Crescent Point's derivative assets and liabilities are transacted in active markets. Crescent Point's long-term investments are 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, reclamation fund, accounts payable and accrued liabilities and dividends payable approximate their carrying amount due to the short-term nature of those instruments. The fair value of the amounts drawn on bank credit facilities is equal to its carrying amount as the facilities bear interest at floating rates and credit spreads that are indicative of market rates. These financial instruments are classified as financial assets and liabilities at amortized cost and are reported at amortized cost.

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.

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, 2017:

($ millions)	2017 Carrying Value	2017 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	282.7	282.7	—	282.7	—
Long-term investments [1]	72.6	72.6	65.1	—	7.5
	355.3	355.3	65.1	282.7	7.5
Financial liabilities					
Derivatives	123.9	123.9	—	123.9	—
Senior guaranteed notes [2]	1,932.0	1,951.3	—	1,951.3	—
	2,055.9	2,075.2	—	2,075.2	—

(1) Long-term investments are comprised of equity securities in public and private 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, 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.

The following table summarizes the fair value as at December 31, 2017 and the change in fair value for the year ended December 31, 2017:

($ millions)	Commodity contracts [1]	Interest contracts	CCS contracts	Foreign exchange contracts	Total
Derivative assets / (liabilities), beginning of year	(60.6)	2.1	373.3	6.9	321.7
Unrealized change in fair value	6.1	7.4	(175.3)	(1.8)	(163.6)
Foreign exchange	0.7	—	—	—	0.7
Derivative assets / (liabilities), end of year	(53.8)	9.5	198.0	5.1	158.8
Derivative assets, end of year	23.2	9.5	244.9	5.1	282.7
Derivative liabilities, end of year	(77.0)	—	(46.9)	—	(123.9)

(1) Includes oil, gas and power 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, 2018 and December 31, 2017:

			2018			2017
($ millions)	Asset	Liability	Net	Asset	Liability	Net
Gross amount	595.6	—	595.6	283.5	(124.7)	158.8
Amount offset	—	—	—	(0.8)	0.8	—
Net amount	595.6	—	595.6	282.7	(123.9)	158.8

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.

Market risk

Market risk is the risk that the fair value or future cash flows of a derivative will fluctuate because of changes in market prices. Market risk is comprised of commodity price risk, interest rate risk and foreign exchange risk as discussed below.

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. As a means to mitigate the exposure to commodity price volatility, the Company has entered into various derivative agreements and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors. Unless otherwise approved by the Board of Directors, the Company can hedge benchmark prices on up to 65 percent of after royalty volumes using a portfolio of swaps, collars and put option instruments and can hedge price differentials on up to 35 percent of after royalty volumes using a combination of financial derivatives and fixed differential physical contracts.

Crude oil - To partially mitigate exposure to crude oil commodity price risk, the Company enters into option contracts and swaps to manage the Cdn$ and US$ WTI price fluctuations. The Company also enters physical delivery and derivative WTI price differential contracts which manage the spread between US$ WTI and various stream prices. The Company manages physical delivery contracts with fixed differentials on a month-to-month spot and on a term contract basis. As at December 31, 2018, Crescent Point had committed, on a term contract basis, to deliver an average of approximately 14,900 bbl/d of liquids for calendar 2019, 9,900 bbl/d of crude oil for calendar 2020,9,500 bbl/d of crude oil for calendar 2021,6,500 bbl/d of crude oil for calendar 2022 and 4,000 bbl/d of crude oil for calendar 2023 to 2027.

Natural gas - To partially mitigate exposure to natural gas commodity price risk, the Company enters into AECO natural gas swaps, which manage the AECO natural gas price fluctuations.

Power - To partially mitigate exposure to electricity price changes, the Company enters into swaps or fixed price physical delivery contracts which fix the power price.

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at December 31, 2018 and December 31, 2017 to fluctuations in commodity prices or differentials, with all other variables held constant. When assessing the potential impact of these commodity price or differential changes, the Company believes a 10 percent near-term volatility is a reasonable measure. Fluctuations in commodity prices or differentials potentially would have resulted in unrealized gains (losses) impacting income before tax as follows:

	Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Year ended December 31, 2018		Year ended December 31, 2017	
	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Commodity price				
Crude oil	(75.6)	61.6	(150.9)	139.4
Natural gas	(0.7)	0.7	(2.9)	2.9

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, 2018, a 1% increase or decrease in the interest rate on floating rate debt would amount to an impact on income before tax of $16.1 million (December 31, 2017 - $17.8 million, respectively).

The Company partially mitigates its exposure to interest rate changes by entering into interest rate swap transactions. The following sensitivities show the resulting unrealized gains (losses) and the impact on income before tax of the respective changes in the applicable forward interest rates as at December 31, 2018 and December 31, 2017 with all other variables held constant:

	Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Year ended December 31, 2018		Year ended December 31, 2017	
Forward interest rates	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Interest rate swaps	1.1	(1.1)	1.9	(1.9)

Foreign exchange risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. 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.

The Company partially mitigates its exposure to foreign exchange rate changes by entering into US dollar swaps. Crescent Point entered 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 sensitivities show the resulting unrealized gains (losses) and the impact on income before tax of the respective changes in the period end and applicable forward foreign exchange rates at December 31, 2018 and December 31, 2017 with all other variables held constant:

		Impact on Income Before Tax		Impact on Income Before Tax	
($ millions)	Exchange Rate	Year ended December 31, 2018		Year ended December 31, 2017	
Cdn$ relative to US$		Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
US dollar long-term debt	Period End	394.2	(394.2)	390.1	(390.1)
Cross currency swaps	Forward	(402.3)	402.3	(402.5)	402.5
Foreign exchange swaps	Forward	(9.4)	9.4	(3.7)	3.7

Credit risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. 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. The Company monitors the creditworthiness and concentration of credit with customers of its physical oil and gas sales. 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% of the Company's oil and gas sales are with entities considered investment grade.

The Company is authorized to transact derivative contracts with counterparties rated A (or equivalent) or better, based on the lowest rating of the three ratings providers. Should one of the Company's financial counterparties be downgraded below the A rating limit, the Chief Financial Officer will advise the Audit Committee and provide recommendations to minimize the Company's credit risk to that counterparty. The maximum credit exposure associated with accounts receivable is the total carrying amount and the maximum exposure associated with the derivative instruments approximates their fair value.

At December 31, 2018, approximately 5 percent (December 31, 2017 - 4 percent) of the Company's accounts receivable balance was outstanding for more than 90 days and the Company's average expected credit loss was 2.95% on a portion of the Company's accounts receivable balance relating to joint venture receivables.

Liquidity risk

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. 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, 2018, the Company had available unused borrowing capacity on bank credit facilities of approximately $1.62 billion, including $8.0 million outstanding letters of credit and cash of $15.3 million.

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	532.9	—	—	—	532.9
Dividends payable	16.5	—	—	—	16.5
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. The current maturity date of the Company's facilities is June 10, 2021. 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, 2017 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	613.3	—	—	—	613.3
Dividends payable	16.8	—	—	—	16.8
Derivative liabilities [1]	55.6	2.5	—	—	58.1
Senior guaranteed notes [2]	126.0	371.1	512.0	1,048.9	2,058.0
Bank credit facilities [3]	98.3	2,316.7	—	—	2,415.0

(1) These amounts exclude undiscounted cash outflows pursuant to the CCS and foreign exchange swap related to the senior guaranteed notes, and the CCS related to LIBOR loans.

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

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2017 and includes undiscounted cash outflows pursuant to the CCS related to LIBOR loans.

c) Derivative contracts

The Company enters into derivative crude oil, natural gas, power, interest rate, cross currency and foreign exchange contracts along with crude oil differential contracts to manage its exposure to fluctuations in the price of crude oil, gas, power, foreign exchange and interest on debt.

The following is a summary of the derivative contracts in place as at December 31, 2018:

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar [1]					
		Swap	Three-way Collar		
Term	Volume (bbls/d)	Average Price ($/bbl)	Average Sold Call Price ($/bbl)	Average Bought Put Price ($/bbl)	Average Sold Put Price ($/bbl)
2019	47,151	73.51	82.31	77.24	66.52
2020 January - June	8,470	—	92.08	84.77	71.00

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

Financial WTI Crude Oil Derivative Contracts – US Dollar [1]				
		Three-way Collar		
Term	Volume (bbls/d)	Average Sold Call Price (US$/bbl)	Average Bought Put Price (US$/bbl)	Average Sold Put Price (US$/bbl)
2019 January - June	8,972	56.01	49.89	43.00

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

Financial AECO Natural Gas Derivative Contracts – Canadian Dollar [1]		
Term	Average Volume (GJ/d)	Average Swap Price ($/GJ)
2019	19,948	2.71

(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 2019 - August 2020	Swap	50.0	1.16
January 2019 - August 2020	Swap	50.0	1.16
January 2019 - August 2020	Swap	100.0	1.15
January 2019 - September 2020	Swap	50.0	1.14
January 2019 - 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 2019	Swap	250.0	4.54	327.9	3.80
January 2019	Swap	230.0	4.54	301.8	3.80
January 2019	Swap	100.0	4.54	131.1	3.80
January 2019	Swap	200.0	4.54	262.5	3.80
January 2019	Swap	150.0	4.54	196.6	3.81
January 2019	Swap	200.0	4.52	265.7	3.75
January 2019	Swap	100.0	4.52	132.9	3.75
January 2019	Swap	90.0	4.52	119.5	3.73
January 2019	Swap	90.0	4.52	119.6	3.74
January 2019 - May 2019	Swap	68.0	3.39	66.7	4.53
January 2019 - March 2020	Swap	155.0	6.03	158.3	6.45
January 2019 - April 2021	Swap	82.0	5.13	79.0	5.83
January 2019 - June 2021	Swap	52.5	3.29	56.3	3.59
January 2019 - May 2022	Swap	170.0	4.00	166.9	5.03
January 2019 - April 2023	Swap	61.5	4.12	80.3	3.71
January 2019 - June 2023	Swap	270.0	3.78	274.7	4.32
January 2019 - June 2024	Swap	257.5	3.75	276.4	4.03
January 2019 - April 2025	Swap	82.0	4.30	107.0	3.98
January 2019 - April 2025	Swap	230.0	4.08	291.1	4.13
January 2019 - 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 2019	Swap	39.3	53.1
May 2022	Swap	30.0	32.2

26. RELATED PARTY TRANSACTIONS

All related party transactions are recorded at the exchange amount.

During the year ended December 31, 2018, Crescent Point recorded $11.6 million (year ended December 31, 2017 - $12.9 million) of expenditures in the normal course of business to an oilfield services company of which a director of Crescent Point is a director and officer. The oilfield services company is one of only a few specialized service providers in their area of expertise with capacity and geographical presence to meet the Company's needs. The service company was selected, along with a few other key vendors, to provide goods and services as part of a comprehensive and competitive request for proposal process with key factors of its success including the unique nature of proprietary products, the ability to service specific geographic regions, proven safety performance and competitive pricing.

Compensation of Key Management Personnel

Key management personnel of the Company consists of its directors and executive officers. In addition to the directors fees and salaries paid to the directors and officers, respectively, the directors participate in the Restricted Share Bonus Plan and DSU Plan and the officers participate in the Restricted Share Bonus Plan and PSU Plan. The Company recorded $7.7 million (year ended December 31, 2017 - $7.5 million) relating to compensation of key management personnel and $11.3 million (year ended December 31, 2017 - nil) relating to executive severance as general and administrative expenses for the year ended December 31, 2018. Share-based compensation costs relating to compensation of key management personnel and severance were $22.6 million (year ended December 31, 2017 –$21.7 million) and $2.8 million (year ended December 31, 2017 - nil), respectively.

27. COMMITMENTS

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 leases (building, vehicle and equipment) (1)	35.3	64.5	54.3	194.5	348.6
Transportation commitments	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.

At December 31, 2017, 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 leases (building and vehicle) (1)	30.2	53.1	52.1	217.0	352.4
Transportation commitments	17.8	29.6	22.9	37.4	107.7
Total contractual commitments	48.0	82.7	75.0	254.4	460.1

(1) Included in operating leases are recoveries of rent expense on office space the Company has subleased of $50.6 million.

28. SIGNIFICANT SUBSIDIARIES

The Company has the following significant subsidiaries, each owned100% directly and indirectly, at December 31, 2018:

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

29. SUPPLEMENTAL DISCLOSURES

Comprehensive Income Statement Presentation

The Company's statements of comprehensive income are prepared primarily by nature of expense, with the exception of compensation expenses which are included in the operating, general and administrative and share-based compensation line items, as follows:

($ millions)	**2018**	2017
Operating	**96.3**	92.9
General and administrative	**88.8**	69.6
Share-based compensation	**46.0**	62.0
Total compensation expenses	**231.1**	224.5

Cash flow statement presentation

($ millions)	**2018**	2017
Operating activities		
Changes in non-cash working capital:		
Accounts receivable	**89.8**	(21.6)
Prepaids and deposits	**—**	0.9
Accounts payable and accrued liabilities	**(39.6)**	13.9
Other current liabilities	**(11.5)**	24.0
Other long-term liabilities	**(1.5)**	1.5
	37.2	18.7
Investing activities		
Changes in non-cash working capital:		
Accounts receivable	**(25.0)**	(26.0)
Accounts payable and accrued liabilities	**(56.6)**	(39.8)
	(81.6)	(65.8)
Financing activities		
Changes in non-cash working capital:		
Dividends payable	**(0.3)**	0.5

($ millions)	**2018**	2017
Other		
Lease inducement	**(3.6)**	(3.6)
Onerous contract provision	**(1.5)**	2.2
Translation of US dollar derivatives	**2.6**	(0.7)
	(2.5)	(2.1)

Supplementary Financing Cash Flow Information

The Company's reconciliation of cash flow from financing activities is outlined in the table below:

($ millions)	Dividends payable	Current portion of long-term debt	Long-term debt	Shareholders' capital
December 31, 2017	**16.8**	**63.8**	**4,047.2**	**16,489.6**
Changes from cash flow from financing activities:				
Redemption of restricted shares				**(1.7)**
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		**14.7**	**55.6**	
Cash dividends paid	**(198.8)**			
Non-cash changes:				
Redemption of restricted shares				**59.0**
Reclassified to current		**94.2**	**(94.2)**	
Cash dividends declared	**198.5**			
Foreign exchange		**(7.9)**	**261.0**	
December 31, 2018	**16.5**	**99.8**	**4,176.9**	**16,546.9**
December 31, 2016	16.3	90.6	3,730.1	16,400.2
Changes from cash flow from financing activities:				
Redemption of restricted shares				(2.3)
Share issue costs				(0.3)
Increase in bank debt, net			635.9	
Repayment of senior guaranteed notes		(90.3)		
Realized gain (loss) on cross currency swap maturity		21.4	(76.0)	
Cash dividends paid	(197.2)			
Non-cash changes:				
Redemption of restricted shares				91.9
Deferred taxes on share issue costs				0.1
Reclassified to current		68.3	(68.3)	
Cash dividends declared	197.7			
Foreign exchange		(26.2)	(174.5)	
December 31, 2017	16.8	63.8	4,047.2	16,489.6

30. GEOGRAPHICAL DISCLOSURE

As at December 31, 2018, Crescent Point's non-current assets related to the U.S. foreign operations was $2.46 billion (December 31, 2017 - $2.74 billion). See Note 18 - "Oil and Gas Sales" for Crescent Point's oil and gas sales related to the U.S. foreign operations.

Directors

Robert Heinemann, Chairman

Rene Amirault [4]

Peter Bannister [3] [4]

Laura Cillis [1] [2]

John Dielwart [6]

Ted Goldthorpe [1] [5]

Mike Jackson [1] [2] [5]

Francois Langlois [3] [4] [5]

Barbara Munroe [2] [5]

Gerald Romanzin [1] [3]

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] Member effective March 7, 2019

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

Derek Christie
Senior Vice President, Exploration and Corporate Development

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Scott Tuttle
Senior Vice President, Human Resources and Corporate Services

Head Office

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Calgary, Alberta T2P 1G1
Tel: (403) 693-0020
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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

Exhibit 99.3

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated March 6, 2019 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2018 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, 2018 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.

Results of Operations

Production

	2018	2017	% Change
Crude oil (bbls/d)	**140,298**	139,996	—
NGLs (bbls/d)	**19,805**	18,250	9
Natural gas (mcf/d)	**108,376**	106,599	2
Total (boe/d)	**178,166**	176,013	1
Crude oil and NGLs (%)	**90**	90	—
Natural gas (%)	**10**	10	—
Total (%)	**100**	100	—

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

Production By Area (boe/d)	**2018**	2017	% Change
Williston Basin	**102,624**	103,070	—
Southwest Saskatchewan	**39,913**	41,737	(4)
Uinta Basin	**22,640**	18,040	25
Other	**12,989**	13,166	(1)
Total	**178,166**	176,013	1

Total production remained relatively consistent in 2018 compared to 2017, as the impact of non-core dispositions in Canada and natural declines was largely offset by new production added through the Company's capital development program and growing production in the United States. Natural gas liquids ("NGLs") volumes increased mainly due to additional wells drilled in the year and processing efficiencies realized through expanded infrastructure.

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

In the year ended December 31, 2018, the Company drilled 755 (605.4 net) wells, focused primarily in the Williston Basin, southwest Saskatchewan and the Uinta Basin.

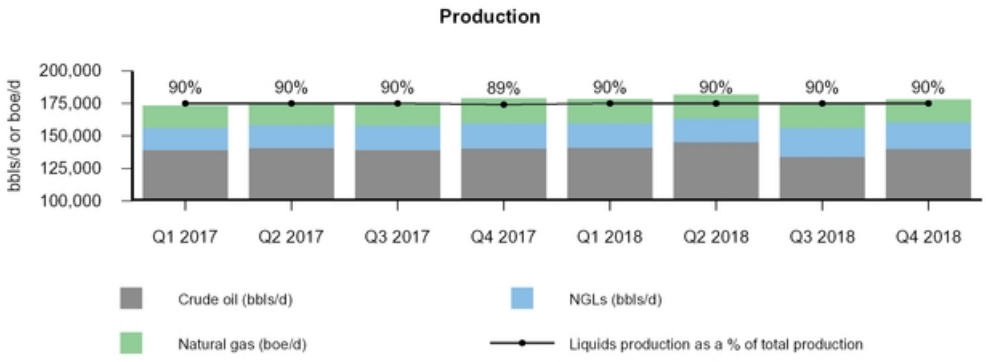


Exhibit 1

Marketing and Prices

Average Selling Prices [1]	2018	2017	% Change
Crude oil ($/bbl)	**69.43**	59.05	18
NGLs ($/bbl)	**33.66**	27.80	21
Natural gas ($/mcf)	**2.25**	2.61	(14)
Total ($/boe)	**59.78**	51.43	16

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

Benchmark Pricing	2018	2017	% Change
Crude Oil Prices			
WTI crude oil (US$/bbl) [1]	**64.78**	50.95	27
WTI crude oil (Cdn$/bbl)	**83.91**	66.08	27
Crude Oil Differentials			
LSB crude oil (Cdn$/bbl) [2]	**(10.75)**	(4.04)	166
FOS crude oil (Cdn$/bbl) [3]	**(25.65)**	(13.73)	87
Wax crude oil (US$/bbl) [4]	**(8.97)**	(4.75)	89
UHC crude oil (US$/bbl) [5]	**(2.39)**	0.15	(1,693)
Natural Gas Prices			
AECO daily spot natural gas (Cdn$/mcf) [6]	**1.50**	2.15	(30)
AECO monthly index natural gas (Cdn$/mcf)	**1.53**	2.42	(37)
NYMEX natural gas (US$/mmbtu) [7]	**3.08**	3.11	(1)
Foreign Exchange Rate			
Exchange rate (US$/Cdn$)	**0.772**	0.771	—

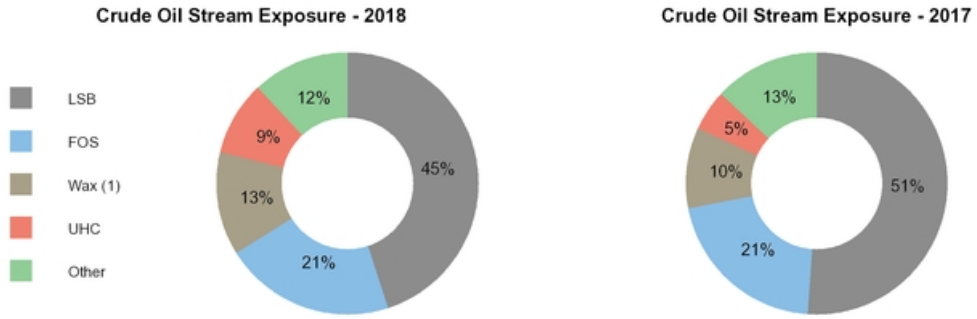
(1) WTI refers to the West Texas Intermediate crude oil price.
(2) LSB refers to the Light Sour Blend crude oil price.
(3) FOS refers to the Fosterton crude oil price, which typically receives a premium to Western Canadian Select ("WCS") prices.
(4) Wax crude oil is based on posted yellow wax prices in Salt Lake City. Black wax pricing is relatively consistent with yellow wax.
(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.

WTI benchmark price increased 27 percent in 2018, reflecting geopolitical fears and potential supply disruptions. U.S. sanctions on Iran and OPEC cuts from Saudi Arabia and Russia, as well as declines in Venezuela helped ease global oil supply and bring back balance to the market.

Canadian natural gas prices weakened in 2018 with the AECO daily benchmark price decreasing 30 percent compared to 2017. The decrease was due to increased production of liquid rich plays in northeast British Columbia and northwest Alberta, which came with an increase in natural gas production flooding the Alberta market with limited increases in export capacity.

U.S. natural gas prices remained relatively consistent with the average NYMEX benchmark price decreasing only 1 percent due to increased LNG exports throughout 2018.

Exhibit 2



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

The Company's crude oil production is exposed to differentials primarily based on the geography and quality of its production base. For the year ended December 31, 2018, 45 percent of the Company's crude oil production was in southeast Saskatchewan and was exposed to LSB crude oil pricing. 21 percent of the Company's crude oil production was in southwest Saskatchewan, weighted to medium crude oil, and was exposed to FOS crude oil pricing. 13 percent of the Company's crude oil production was in the Uinta Basin, priced at a negotiated discount to WTI that is primarily based on yellow and black wax posted prices. 9 percent of the Company's crude oil production was in North Dakota, exposed to UHC crude oil pricing. The remainder of the Company's crude oil production was exposed to Alberta-indexed crude oil pricing.

Canadian crude oil differentials widened in 2018 due to increased oil supply in Western Canada and lack of adequate pipeline and rail capacity. In the U.S., yellow and black wax differentials widened due to increased production in the Uinta Basin and periodic, temporary outages in the Salt Lake City refining complex. The Company's 2018 corporate oil differential widened with these market differentials. However, Crescent Point's realized pricing was stronger than Canadian index prices due to the quality and location of its production. Additionally, the Company was not affected by the Alberta government's mandatory production curtailment.

For the year ended December 31, 2018, the Company's average selling price for crude oil increased 18 percent from 2017, primarily as a result of a 27 percent increase in the US$ WTI benchmark price, partially offset by a wider corporate oil price differential. Crescent Point's corporate oil differential relative to Cdn$ WTI for the year ended December 31, 2018 was $14.48 per bbl compared to $7.03 per bbl in 2017.

The Company's average selling price for NGLs in 2018 increased 21 percent from $27.80 per bbl to $33.66 per bbl. Average selling prices for NGLs were impacted by the strengthening of propane, butane and condensate prices resulting from the increases in crude oil prices and offshore propane exports.

The Company's average selling price for natural gas in 2018 decreased 14 percent from $2.61 per mcf to $2.25 per mcf, primarily as a result of the 30 percent decrease in the AECO benchmark price, partially offset by growth in U.S gas production which is exposed to NYMEX pricing.

Exhibit 3

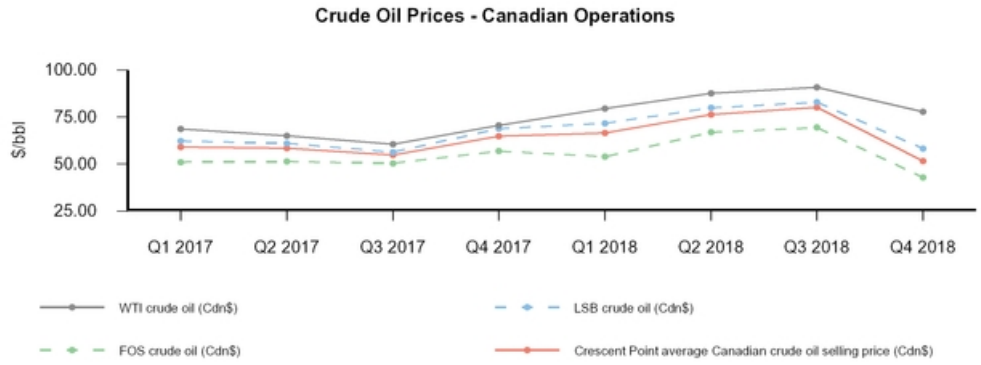


Exhibit 4

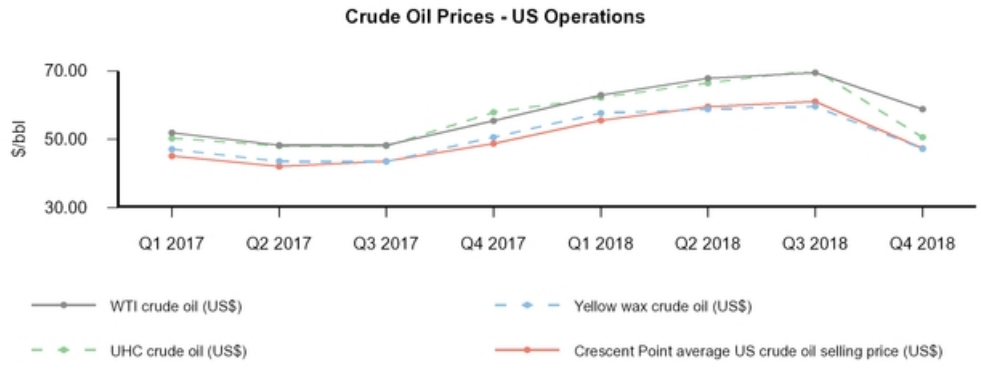


Exhibit 5

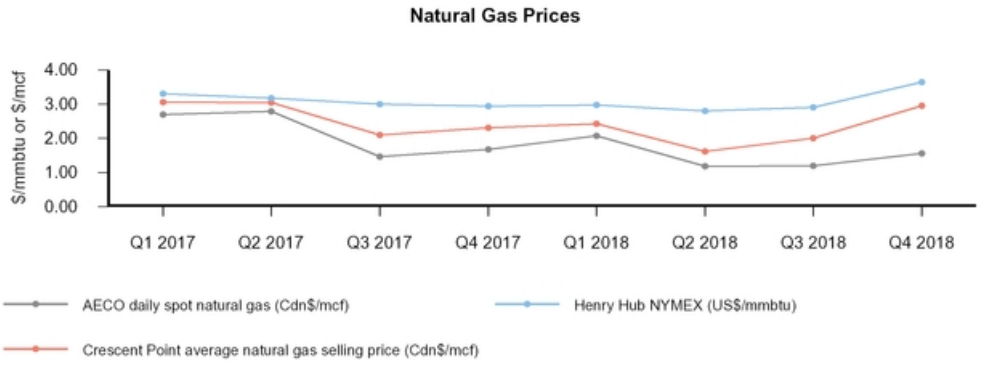
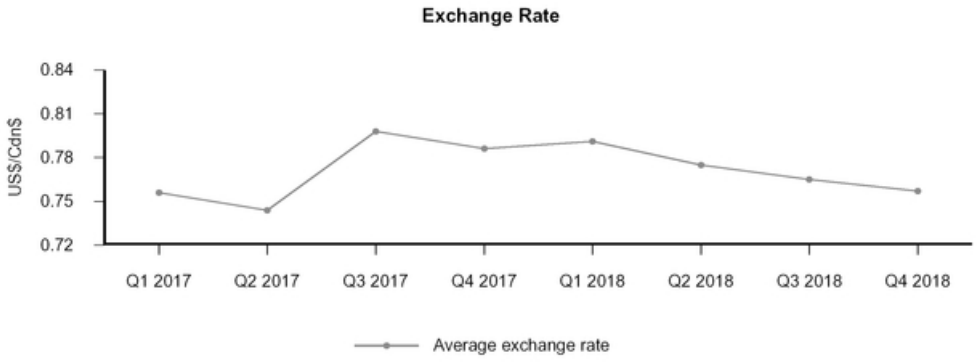


Exhibit 6



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 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. For commodities, Crescent Point's risk management program allows for hedging a forward profile of up to 3½ years and up to 65 percent of net royalty interest production, unless otherwise approved by the Board of Directors.

With the ongoing volatility of price differentials between WTI and western Canadian crude prices, Crescent Point also hedges price differentials as a part of its risk management program. The Company uses a combination of financial derivatives and fixed differential physical contracts to hedge these price differentials. For price differential hedging, Crescent Point's risk management program allows for hedging a forward profile of up to 3½ years, and up to 35 percent net of royalty interest production. In addition, the Company can deliver crude oil through its various rail terminals to provide access to diversified markets and pricing. See Note 25 - "Financial Instruments and Derivatives" in the annual consolidated financial statements for the year ended December 31, 2018 for additional information on the Company's derivatives.

The Company has not designated any of its risk management activities as accounting hedges under IFRS 9,*Financial Instruments*, and, accordingly, has recorded its derivatives at fair value with changes in fair value recorded in net income.

IFRS 9, *Financial Instruments*, gives guidelines for accounting for financial derivatives not designated as accounting hedges. Financial derivatives that have not settled during the current period are fair valued. The change in fair value from the previous period represents a gain or loss that is recorded in net income. As such, if benchmark oil and natural gas prices rise during the period, the Company records a loss based on the change in price multiplied by the volume of oil and natural gas hedged. If prices fall during the period, the Company records a gain. The prices used to record the actual gain or loss are subject to an adjustment for volatility and the resulting gain (asset) or loss (liability) is discounted to a present value using a risk free rate adjusted for counterparty credit risk.

Crescent Point's underlying physical reserves are not fair valued each quarter, hence no gain or loss associated with price changes is recorded; the Company realizes the benefit/detriment of any price increase/decrease in the period in which the physical sales occur.

The Company's financial results should be viewed with the understanding that the estimated future gain or loss on financial derivatives is recorded in the current period's results, while the estimated future value of the underlying physical sales is not.

The following is a summary of the realized derivative gains (losses) on crude oil and natural gas derivative contracts:

($ millions, except volume amounts)	**2018**	2017	% Change
Average crude oil volumes hedged (bbls/d) [1]	**79,066**	57,196	38
Crude oil realized derivative gain (loss) [1]	**(276.7)**	89.5	(409)
per bbl	**(5.40)**	1.75	(409)
Average natural gas volumes hedged (GJ/d) [2]	**33,973**	41,356	(18)
Natural gas realized derivative gain	**16.9**	11.7	44
per mcf	**0.43**	0.30	43
Average barrels of oil equivalent hedged (boe/d) [1]	**84,432**	63,729	32
Total realized derivative gains (losses) [1]	**(259.8)**	101.2	(357)
per boe	**(4.00)**	1.58	(353)

(1) The crude oil realized derivative gain in 2017 includes realized derivative gains and losses on financial price differential contracts. The average crude oil volumes hedged and average barrels of oil equivalent hedged do not include the hedged volumes related to financial price differential contracts.

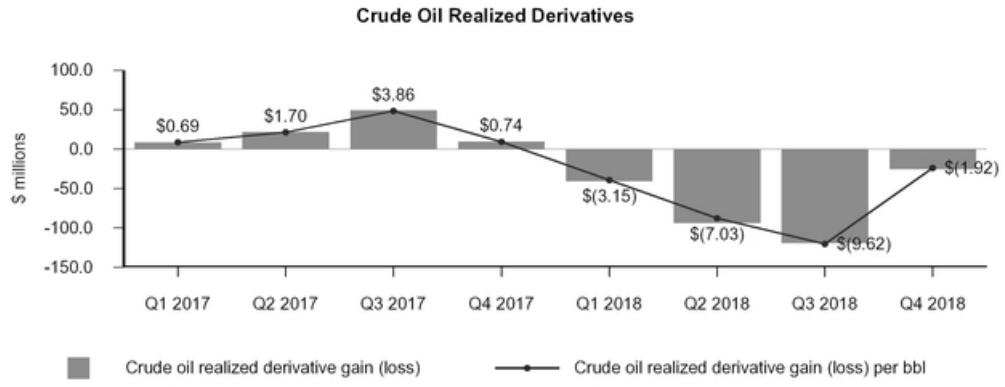
(2) GJ/d is defined as gigajoules per day.

The Company recorded a total realized derivative loss of $259.8 million for the year ended December 31, 2018, compared to a total realized derivative gain of $101.2 million in 2017.

The Company's realized derivative loss for crude oil was $276.7 million for the year ended December 31, 2018, compared to a realized derivative gain of $89.5 million in 2017. The realized derivative loss in 2018 was largely attributable to the increase in the Cdn$ WTI benchmark price, partially offset by the increase in the Company's average derivative crude oil price. During the year ended December 31, 2018, the Company's average derivative crude oil price increased by 6 percent or $3.95 per bbl, from $70.37 per bbl in 2017 to $74.32 per bbl in 2018.

Crescent Point's realized derivative gain for gas was $16.9 million for the year ended December 31, 2018, compared to $11.7 million in 2017. The increased realized derivative gain in 2018 was largely attributable to the decrease in the AECO monthly index price, partially offset by the decrease in the Company's average derivative gas price and gas volumes hedged. During the year ended December 31, 2018, the Company's average derivative gas price decreased by 9 percent or $0.27 per GJ, from $3.09 per GJ in 2017 to $2.82 per GJ in 2018.

Exhibit 7



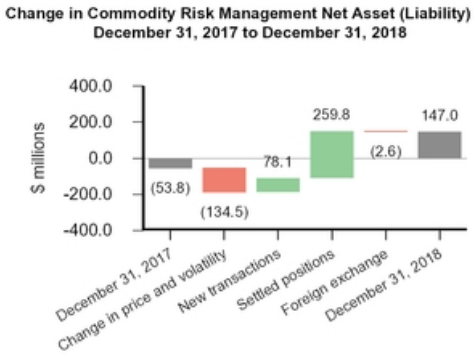
The following is a summary of the Company's unrealized derivative gains (losses):

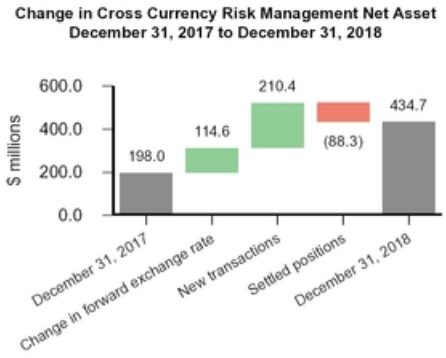
($ millions)	**2018**	2017	% Change
Crude oil	**216.1**	(20.1)	(1,175)
Natural gas	**(12.7)**	25.6	(150)
Interest	**(4.0)**	7.4	(154)
Power	**—**	0.6	(100)
Cross currency	**236.7**	(175.3)	(235)
Foreign exchange	**3.3**	(1.8)	(283)
Total unrealized derivative gains (losses)	**439.4**	(163.6)	(369)

The Company recognized a total unrealized derivative gain of $439.4 million for the year ended December 31, 2018 compared to an unrealized derivative loss of $163.6 million in 2017, primarily due to a $216.1 million unrealized derivative gain on crude oil contracts compared to a $20.1 million unrealized derivative loss in 2017. The unrealized crude oil derivative gain for the year ended December 31, 2018 was primarily attributable to the maturity of out-of-the-money contract months and the decrease in the Cdn$ WTI and US$ WTI forward benchmark prices at December 31, 2018 compared to December 31, 2017.

The total unrealized derivative gain was also attributable to a $236.7 million unrealized derivative gain on cross currency swaps ("CCS") compared to a $175.3 million unrealized derivative loss in 2017. The unrealized CCS derivative gain for the year ended December 31, 2018 was primarily the result of the weaker forward Canadian dollar at December 31, 2018 compared to December 31, 2017. The unrealized CCS derivative loss for the year ended December 31, 2017 was primarily the result of the stronger forward Canadian dollar at December 31, 2017 compared to December 31, 2016.

Exhibit 8





(1) Includes oil and gas contracts.

Oil and Gas Sales

($ millions) (1)	**2018**	2017	% Change
Crude oil sales	**3,555.3**	3,017.2	18
NGL sales	**243.3**	185.2	31
Natural gas sales	**88.9**	101.5	(12)
Total oil and gas sales	**3,887.5**	3,303.9	18

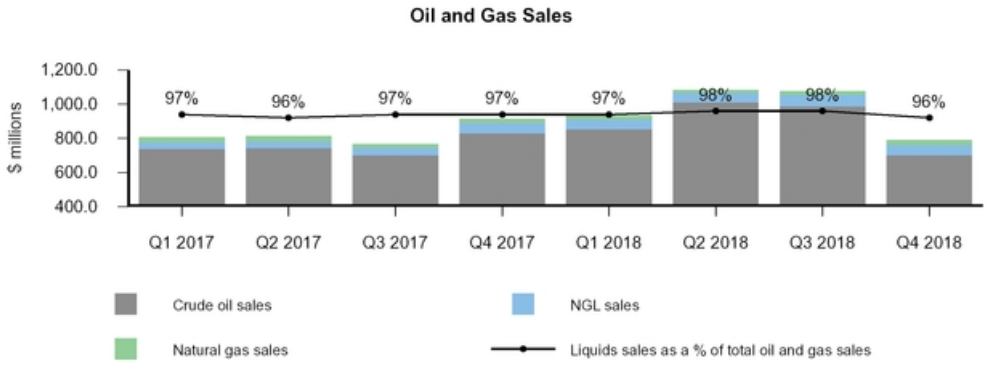
(1) Oil and gas sales are reported before realized derivatives .

Crude oil sales increased 18 percent in the year ended December 31, 2018, from $3.02 billion in 2017 to $3.56 billion in 2018, primarily due to the 18 percent increase in realized prices.

NGL sales increased 31 percent in the year ended December 31, 2018 compared to 2017, primarily due to the 21 percent increase in realized NGL prices, and the 9 percent increase in NGL production.

Natural gas sales decreased 12 percent in the year ended December 31, 2018 compared to 2017, primarily due to the 14 percent decrease in realized natural gas prices, driven by the decrease in the AECO daily benchmark price, partially offset by the 2 percent increase in natural gas production.

Exhibit 9

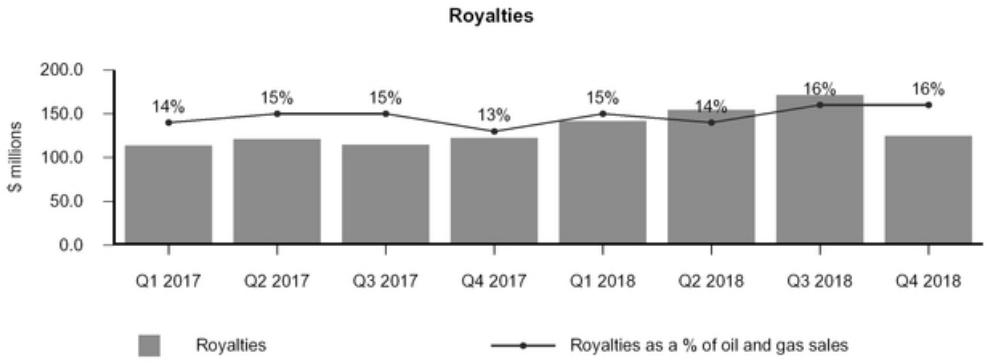


Royalties

($ millions, except % and per boe amounts)	**2018**	2017	% Change
Royalties	**592.4**	472.2	25
As a % of oil and gas sales	**15**	14	1
Per boe	**9.11**	7.35	24

Royalties increased 25 percent in the year ended December 31, 2018 compared to 2017, largely due to the 18 percent increase in oil and gas sales. Royalties as a percentage of oil and gas sales increased by 1 percent for the year ended December 31, 2018 primarily due to growing revenues in the United States with higher associated royalty burdens.

Exhibit 10

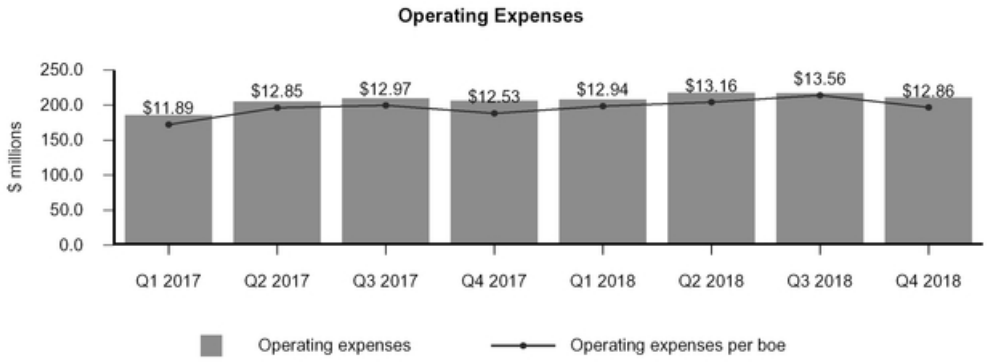


Operating Expenses

($ millions, except per boe amounts)	**2018**	2017	% Change
Operating expenses	**853.8**	807.2	6
Per boe	**13.13**	12.56	5

Operating expenses per boe increased 5 percent in the year ended December 31, 2018 compared to 2017. Overall maintenance activity levels increased in 2018 in conjunction with stronger commodity prices, resulting in higher labour, trucking, chemical and repairs and maintenance costs. In addition, increases in Saskatchewan power rates contributed to higher operating costs.

Exhibit 11



Transportation Expenses

($ millions, except per boe amounts)	**2018**	2017	% Change
Transportation expenses	**131.7**	133.8	(2)
Per boe	**2.02**	2.08	(3)

Transportation expenses per boe decreased in the year ended December 31, 2018 compared to 2017 primarily due to growing production in the United States which have lower associated transportation expenses.

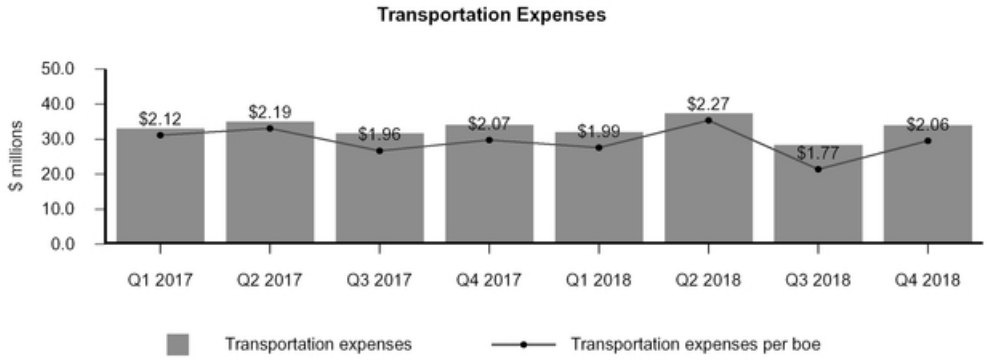


Exhibit 12

Netback

	2018	2017	
	Total [2] ($/boe)	Total [2] ($/boe)	% Change
Average selling price	**59.78**	51.43	16
Royalties	**(9.11)**	(7.35)	24
Operating expenses	**(13.13)**	(12.56)	5
Transportation expenses	**(2.02)**	(2.08)	(3)
Operating netback [1]	**35.52**	29.44	21
Realized gain (loss) on derivatives	**(4.00)**	1.58	(353)
Netback [1]	**31.52**	31.02	2

(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 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, 2018 increased 21 percent to $35.52 per boe from $29.44 per boe in 2017. The increase in the Company's operating netback was primarily the result of the increase in average selling price and the decrease in transportation expenses, partially offset by the increases in royalties and operating expenses. The increase in the Company's netback was the result of the increase in the operating netback, partially offset by the loss on commodity derivatives.

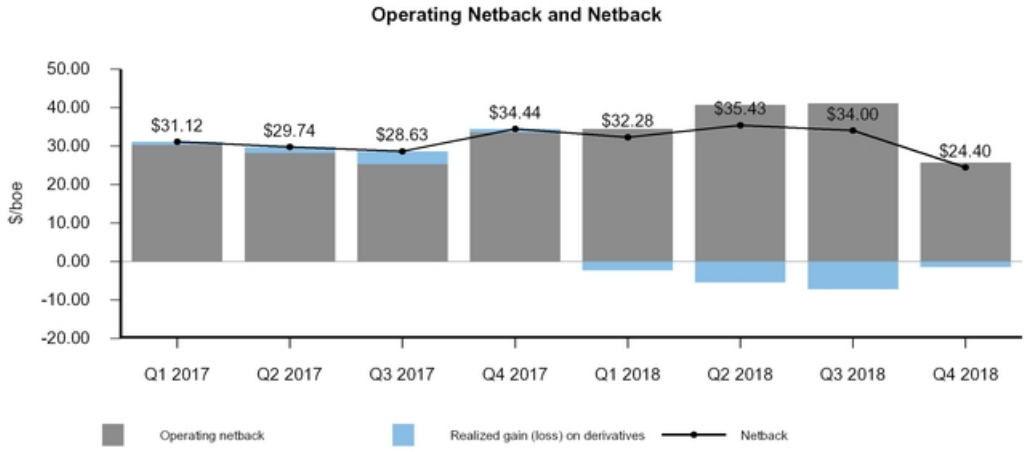
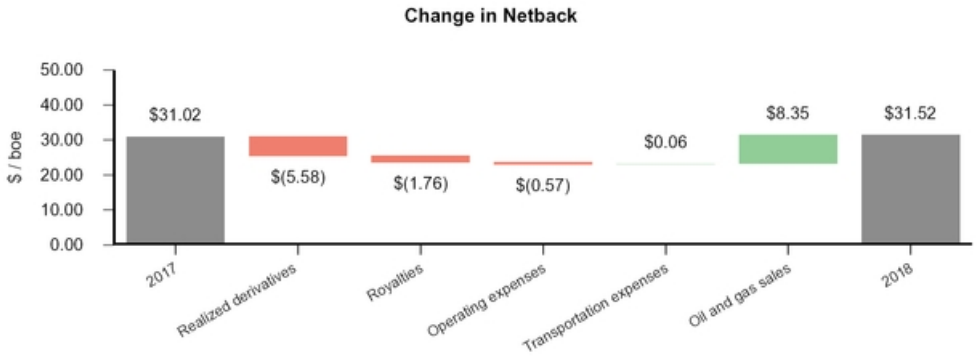


Exhibit 13

Exhibit 14



General and Administrative Expenses

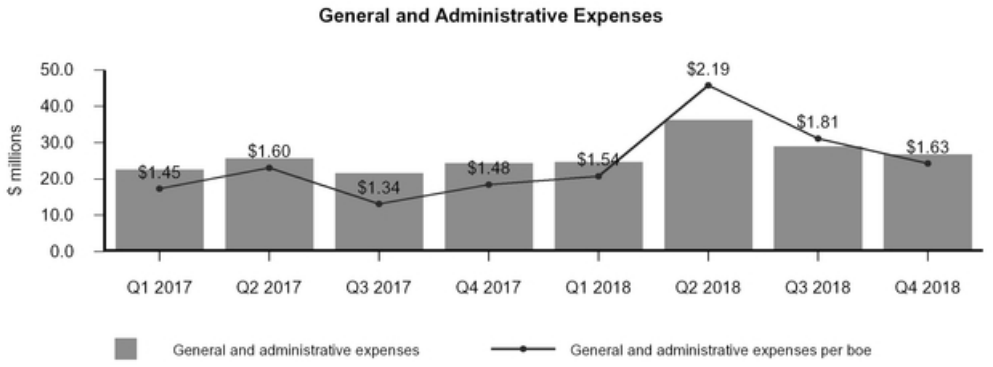
($ millions, except per boe amounts)	**2018**	2017	% Change
General and administrative costs	**162.2**	136.4	19
Capitalized	**(40.3)**	(38.4)	5
Total general and administrative expenses	**121.9**	98.0	24
Transaction costs	**(5.1)**	(3.7)	38
General and administrative expenses	**116.8**	94.3	24
Per boe	**1.80**	1.47	22

General and administrative ("G&A") expenses increased $22.5 million or 24 percent in the year ended December 31, 2018 compared to 2017, primarily due to non-recurring severance costs of $19.1 million from an organizational restructuring, which resulted in a 17 percent decrease in the Company's workforce. In addition, increased shareholder costs and lower overhead recoveries also contributed to the increase in G&A expenses.

G&A expenses per boe increased 22 percent in the year ended December 31, 2018 compared to 2017. The increase was due to the increase in total G&A as noted above, partially offset by slightly higher production volumes.

Transaction costs incurred in the year ended December 31, 2018 relate primarily to major and minor property acquisitions and dispositions. Refer to the Capital Acquisitions and Dispositions section in this MD&A for further information.

Exhibit 15



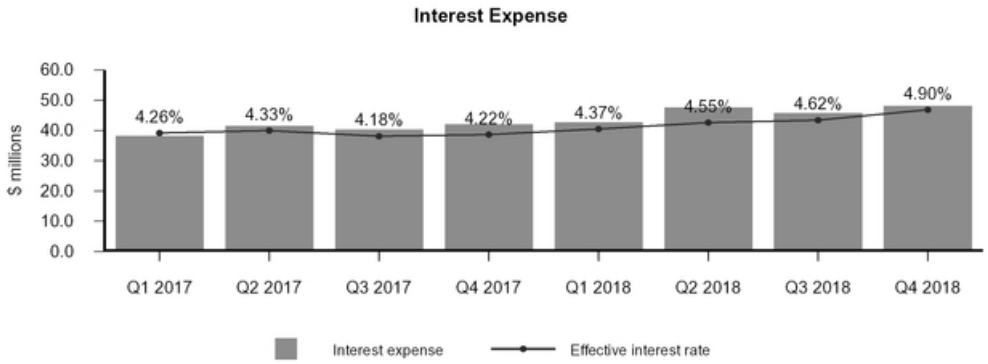
Interest Expense

($ millions, except per boe amounts)	**2018**	2017	% Change
Interest expense	**184.4**	162.3	14
Per boe	**2.84**	2.53	12

In the year ended December 31, 2018, interest expense per boe and interest expense increased 12 percent and 14 percent, respectively, compared to 2017, due to the increase in market interest rates. The Company's effective interest rate in the year ended December 31, 2018 increased to 4.61 percent from 4.25 percent in 2017.

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, 2018, 57 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 16



Foreign Exchange Gain (Loss)

($ millions)	**2018**	2017	% Change
Realized gain (loss)			
CCS - US dollar long-term debt maturities and interest payments	**88.3**	(39.3)	(325)
US dollar long-term debt maturities	**(70.3)**	54.6	(229)
Other	**4.3**	(0.6)	(817)
Unrealized gain (loss)			
Translation of US dollar long-term debt	**(254.2)**	201.2	(226)
Other	**(2.1)**	(0.2)	950
Foreign exchange gain (loss)	**(234.0)**	215.7	(208)

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. Concurrent with the drawdown of US$1.41 billion of LIBOR loans and the issuance of US$1.45 billion senior guaranteed notes, the Company entered into various CCS to hedge its foreign exchange exposure. Under the terms of the CCS, the US dollar amounts of the LIBOR loans and senior guaranteed notes were fixed for purposes of interest and principal repayments at notional amounts of $1.86 billion and $1.58 billion, respectively. 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. The unrealized derivative gains and losses on the CCS and foreign exchange swap are recognized in derivative gains and losses. Refer to the Derivatives section in this MD&A for further information.

The Company records unrealized foreign exchange gains or losses on the translation of the US dollar long-term debt and related accrued interest. During the year ended December 31, 2018, the Company recorded an unrealized foreign exchange loss of $254.2 million on the translation of US dollar long-term debt and accrued interest compared to an unrealized gain of $201.2 million in 2017. The unrealized foreign exchange loss from the translation of US dollar long-term debt and accrued interest for the year ended December 31, 2018 is attributable to a weaker Canadian dollar at December 31, 2018 as compared to December 31, 2017.

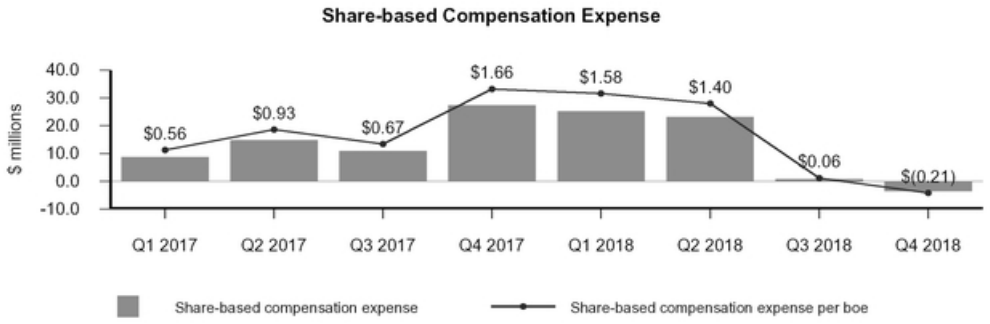
Share-based Compensation Expense

($ millions, except per boe amounts)	**2018**	2017	% Change
Share-based compensation costs	**53.7**	74.0	(27)
Capitalized	**(7.7)**	(12.0)	(36)
Share-based compensation expense	**46.0**	62.0	(26)
Per boe	**0.71**	0.97	(27)

During the year ended December 31, 2018, the Company recorded share-based compensation costs of $53.7 million. The 27 percent decrease in the year ended December 31, 2018 was due to the decrease in the Company's share price and the impact on its share-based compensation plans. The Company recorded share-based compensation expense of $2.8 million related to an organizational restructuring in the year ended December 31, 2018.

During the year ended December 31, 2018, the Company capitalized share-based compensation costs of $7.7 million, a decrease of 36 percent from 2017. The decrease was primarily due to the decrease in total share-based compensation costs as noted above.

Exhibit 17



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.

Under the Restricted Share Bonus Plan at December 31, 2018, the Company was authorized to issue up to 14,256,482 common shares (December 31, 2017 - 12,613,659 common shares). The Company had 3,241,684 restricted shares outstanding at December 31, 2018 (December 31, 2017 - 3,589,024 restricted shares outstanding).

As of the date of this report, the Company had 3,324,082 restricted shares outstanding.

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 the performance multipliers. Based on underlying units prior to any effect of the performance multiplier, the Company had 2,246,314 PSUs outstanding at December 31, 2018 (December 31, 2017 - 4,460,046 PSUs outstanding).

As of the date of this report, the Company had 4,732,353 PSUs outstanding based on underlying units prior to any effect of the performance multiplier.

Deferred Share Unit Plan

The Company has a Deferred Share Unit (“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. Deferred Share Units are settled in cash based on the prevailing Crescent Point share price. The Company had 301,614 DSUs outstanding at December 31, 2018 (December 31, 2017 - 229,470 DSUs outstanding).

As of the date of this report, the Company had 313,142 DSUs outstanding.

Stock Option Plan

In May 2018, the Company approved 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. The Company had 2,048,115 stock options outstanding at December 31, 2018 (December 31, 2017 - nil) at a weighted average exercise price of $10.03 per share.

As of the date of this report, the Company had 2,048,115 stock options outstanding.

Depletion, Depreciation, Amortization and Impairment

($ millions, except per boe amounts)	**2018**	2017	% Change
Depletion and depreciation	**1,421.6**	1,403.5	1
Amortization of exploration and evaluation undeveloped land	**157.2**	134.3	17
Depletion, depreciation and amortization	**1,578.8**	1,537.8	3
Impairment	**3,705.9**	203.6	1,720
Depletion, depreciation, amortization and impairment	**5,284.7**	1,741.4	203
Per boe, before impairment	**24.28**	23.94	1
Per boe	**81.26**	27.11	200

The Company's depletion, depreciation and amortization ("DD&A") rate before impairment remained relatively consistent for the year ended December 31, 2018 compared to 2017.

During the year ended December 31, 2018 the Company recorded impairment expense of $3.71 billion on its development and production assets. The impairment charge reflects the estimated fair value of the Company's assets in the current macroeconomic environment facing Canadian oil and gas companies, including higher cost of capital, regulatory uncertainty and egress limitations, challenged acquisition and divestment markets and significant volatility in commodity prices and differentials. The value of the Company's assets was estimated based on independent evaluator pricing, proved plus probable reserves and discount rates ranging from 15-18 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.

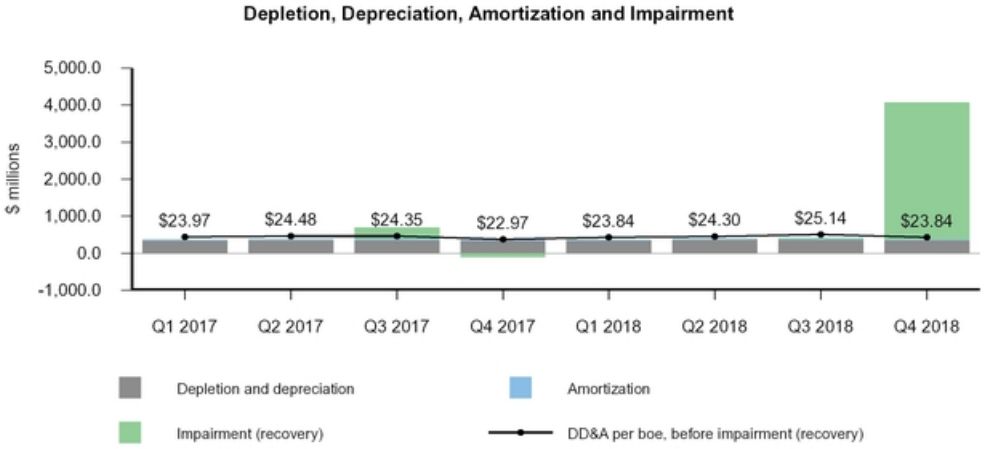


Exhibit 18

Other Income (Loss)

The Company recorded other losses of $143.5 million in the year ended December 31, 2018 compared to other income of $27.8 million in 2017. The other losses in the year ended December 31, 2018 were comprised primarily of losses on capital dispositions and net unrealized losses on long-term investments. The other income in the year ended December 31, 2017 were comprised primarily of gains on capital dispositions, partially offset by unrealized losses on long-term investments.

Taxes

($ millions)	**2018**	2017	% Change
Current tax expense (recovery)	**0.3**	(1.7)	(100)
Deferred tax expense (recovery)	**(938.8)**	102.1	(1,019)

Current Tax Expense (Recovery)

In the year ended December 31, 2018, the Company recorded current tax expense of $0.3 million compared to a current tax recovery of $1.7 million in 2017. The current tax recovery of $1.7 million in the year ended December 31, 2017 was primarily comprised of investment tax credits earned through research and development expenditures on drilling and development activities. Refer to the Company's Annual Information Form for the year ended December 31, 2018 for information on the Company's expected tax horizon.

Deferred Tax Expense (Recovery)

In the year ended December 31, 2018, the Company recorded a deferred tax recovery of $938.8 million compared to a deferred tax expense of $102.1 million in 2017. The deferred tax recovery in the year ended December 31, 2018 is primarily the result of the net loss before income tax in 2018, which resulted primarily due to the impairment expense recorded in the year.

The deferred income tax expense in the year ended December 31, 2017 was primarily due to the impact of the decrease in the U.S. federal corporate tax rate. On December 22, 2017, the United States government enacted the Tax Cuts and Jobs Act, significantly amending U.S. federal income tax provisions which apply to Crescent Point's U.S. subsidiary, Crescent Point Energy U.S. Corp. ("CPEUS"). The most significant change impacting CPEUS was the reduction in the federal corporate income tax rate from 35% to 21%, effective January 1, 2018. In the fourth quarter of 2018, the United States government issued proposed regulations to the interest deductibility, base erosion minimum tax, and anti-hybrid rules. Crescent Point does not expect these other amendments or proposed regulations to materially impact the Company's ongoing provision for current income taxes. The impact of the legislation could differ from expectations, however, due to, among other things, changes in interpretations or assumptions or the announcement of any additional regulations or guidance relating to the legislation.

The deferred tax expense for 2017 also reflects the benefit from the decrease to the Saskatchewan corporate tax rate during the last six months of the year from 12% to 11.5%, as well as a benefit associated with a change in estimated future usable tax pools.

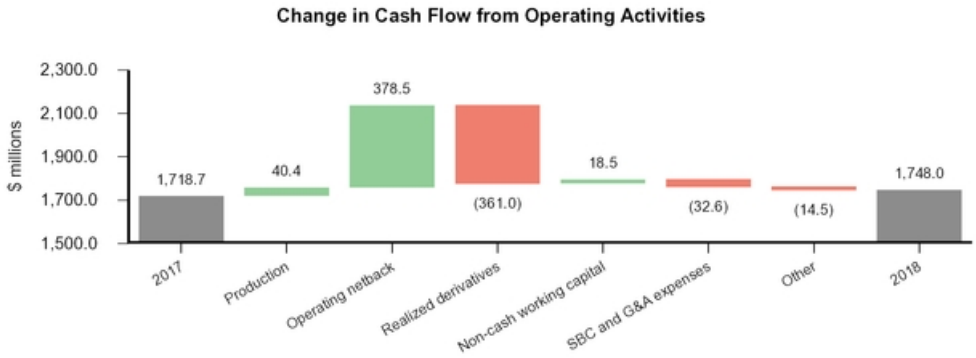
Cash Flow from Operating Activities, Adjusted Funds Flow from Operations, Net Income (Loss) and Adjusted Net Earnings from Operations

($ millions, except per share amounts)	**2018**	2017	% Change
Cash flow from operating activities	**1,748.0**	1,718.7	2
Adjusted funds flow from operations [(1)]	**1,741.2**	1,728.8	1
Net income (loss)	**(2,616.9)**	(124.0)	2,010
Net income (loss) per share - diluted	**(4.77)**	(0.23)	1,974
Adjusted net earnings from operations [(1)]	**234.6**	100.0	135
Adjusted net earnings from operations per share - diluted [(1)]	**0.43**	0.18	139

(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.

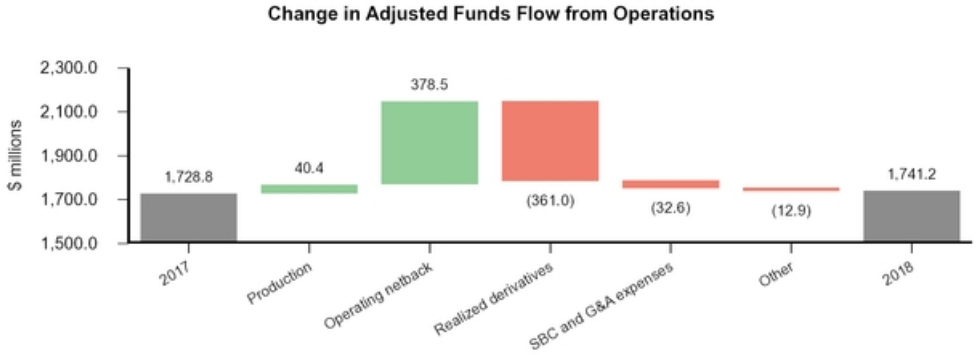
Cash flow from operating activities increased 2 percent to $1.75 billion in the year ended December 31, 2018, compared to $1.72 billion in 2017, due to the changes in adjusted funds flow from operations and fluctuations in working capital, transaction costs and decommissioning expenditures.

Exhibit 19



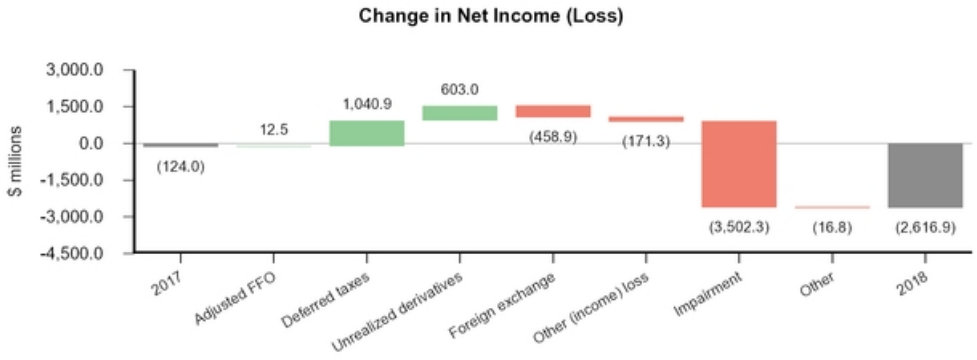
Adjusted funds flow from operations increased to $1.74 billion in the year ended December 31, 2018 from $1.73 billion in 2017. The increase is primarily the result of the increases in operating netback and production volumes, partially offset by the realized hedging loss, interest, cash-settled share-based compensation and severance charges.

Exhibit 20



The Company reported a net loss of $2.62 billion in the year ended December 31, 2018, compared to a net loss of $124.0 million in 2017, primarily as a result of the increase in impairment expense, the foreign exchange loss on long-term debt and losses on dispositions, partially offset by the unrealized derivative gain, the increase in adjusted funds flow from operations and fluctuations in deferred taxes. In the year ended December 31, 2018, the Company recorded net loss per share - diluted of $4.77 compared to net loss per share - diluted of $0.23 in 2017, due to the same reasons discussed above.

Exhibit 21



The Company reported adjusted net earnings from operations of $234.6 million in the year ended December 31, 2018 compared to adjusted net earnings of $100.0 million in 2017, primarily as a result of the increase in adjusted funds flow from operations, the decrease in equity-settled share-based compensation and fluctuations in deferred taxes. Adjusted net earnings from operations per share - diluted increased 139 percent to $0.43 in 2018 compared to $0.18 in 2017, primarily due to the same reasons discussed above.

Dividends

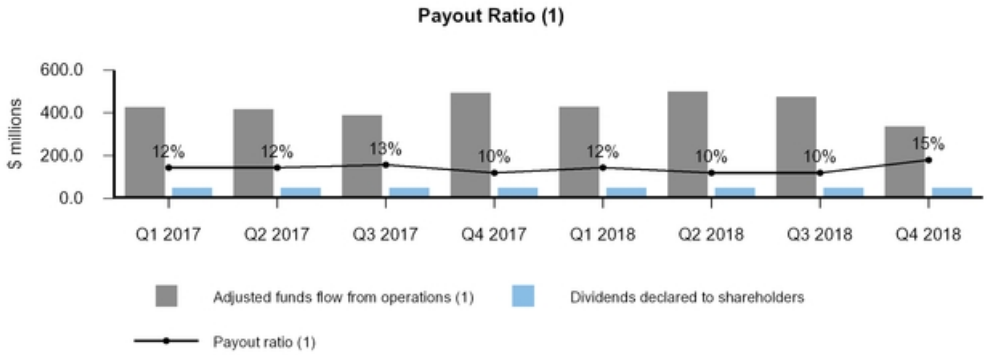
The following table provides a reconciliation of dividends:

($ millions, except per share amounts)	**2018**	2017	% Change
Accumulated dividends, beginning of year	**7,408.6**	7,210.9	3
Dividends declared to shareholders	**198.5**	197.7	—
Accumulated dividends, end of year	**7,607.1**	7,408.6	3
Accumulated dividends per share, beginning of year	**31.80**	31.44	1
Dividends declared to shareholders per share	**0.36**	0.36	—
Accumulated dividends per share, end of year	**32.16**	31.80	1

Dividends remained relatively consistent in the year ended December 31, 2018 compared to 2017.

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

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.

Long-Term Investments

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 each period with the resulting gain or loss recorded in net income. 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.

Private Company

During the year ended December 31, 2018, the Company disposed of its common shares in a private oil and gas company. The investment was classified as financial assets at fair value through profit or loss and fair valued each period with the resulting gain or loss recorded in net income.

Other Long-Term Assets

At December 31, 2018, other long-term assets consist of $18.7 million related to the reclamation fund and $15.8 million of investment tax credits.

The reclamation fund in 2018 remained unchanged from 2017 due to $27.6 million of expenditures offset by contributions of $27.6 million. The expenditures related primarily to decommissioning work completed in Alberta, Saskatchewan and the United States.

Related Party Transactions

All related party transactions are recorded at the exchange amount.

During the year ended December 31, 2018, Crescent Point recorded $11.6 million (year ended December 31, 2017 - $12.9 million) of expenditures in the normal course of business to an oilfield services company of which a director of Crescent Point is a director and officer. The oilfield services company is one of only a few specialized service providers in their area of expertise with capacity and geographical presence to meet the Company's needs. The service company was selected, along with a few other key vendors, to provide goods and services as part of a comprehensive and competitive request for proposal process with key factors of its success being the unique nature of proprietary products, the ability to service specific geographic regions, proven safety performance and/or competitive pricing.

Key management personnel of the Company consists of its directors and executive officers. In addition to the directors fees and salaries paid to the directors and officers, respectively, the directors participate in the Restricted Share Bonus Plan and DSU Plan and the officers participate in the Restricted Share Bonus Plan and PSU Plan. The Company recorded $7.7 million (year ended December 31, 2017 - $7.5 million) relating to compensation of key management personnel and $11.3 million (year ended December 31, 2017 - nil) relating to executive severance as general and administrative expenses for the year ended December 31, 2018. Share-based compensation costs relating to compensation of key management personnel and severance were $22.6 million (year ended December 31, 2017 – $21.7 million) and $2.8 million (year ended December 31, 2017 - nil), respectively.

Capital Expenditures

($ millions)	**2018**	2017	% Change
Capital acquisitions (dispositions), net [1]	**(340.5)**	1.8	(19,017)
Development capital expenditures	**1,769.8**	1,812.1	(2)
Capitalized administration [2]	**40.3**	38.4	5
Corporate assets	**7.7**	4.2	83
Total	**1,477.3**	1,856.5	(20)

(1) Capital acquisitions (dispositions), net represent total consideration for the transactions including net debt and acquired common shares and excludes transaction costs.

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

Capital Acquisitions and Dispositions

Major Property Disposition

Southeast Saskatchewan Asset Disposition

In the year ended December 31, 2018, the Company completed the disposition of non-core assets in southeast Saskatchewan and southwest Manitoba for total proceeds of $213.4 million, resulting in a loss on capital disposition of $57.1 million. This disposition was completed with full tax pools and no working capital items.

Minor Property Acquisitions and Dispositions

In the year ended December 31, 2018, the Company completed minor property acquisitions and dispositions including assets and associated liabilities held for sale at December 31, 2017 for total net proceeds of $127.1 million, resulting in a total loss on capital dispositions of $72.0 million. These minor property acquisitions and dispositions were completed with full tax pools and no working capital items.

Development Capital Expenditures

The Company's development capital expenditures in the year ended December 31, 2018 were $1.77 billion, compared to $1.81 billion in 2017. In 2018, 755 (605.4 net) wells were drilled and $233.6 million was spent on on facilities, land and seismic.

Crescent Point's budgeted capital expenditure guidance for 2019 is $1.20 billion to $1.30 billion, excluding any net land and property acquisitions.

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, 2018 was $244.0 million compared to $251.9 million at December 31, 2017. The decrease of $7.9 million is attributable to the southeast Saskatchewan asset disposition and other minor property dispositions.

Other Current Liabilities

At December 31, 2018, other current liabilities consist of $6.5 million related to the current portion of long-term compensation liability, $3.4 million related to a lease inducement, $2.6 million related to the estimated unrecoverable portion of building leases and $26.9 million related to decommissioning liability.

Other Long-Term Liabilities

At December 31, 2018, other long-term liabilities consist of $3.5 million of long-term compensation liability related to share-based compensation, $36.4 million related to a lease inducement and $8.4 million related to the estimated unrecoverable portion of building leases. The Company's lease inducement is associated with the building lease for Crescent Point's corporate office. This non-cash liability is amortized on a straight-line basis over the term of the lease to June 2030.

Decommissioning Liability

The decommissioning liability decreased by $113.5 million during 2018 from $1.34 billion at December 31, 2017 to $1.23 billion at December 31, 2018. The liability was based on estimated undiscounted cash flows to settle the obligation of $1.29 billion.

Exhibit 23

Liquidity and Capital Resources

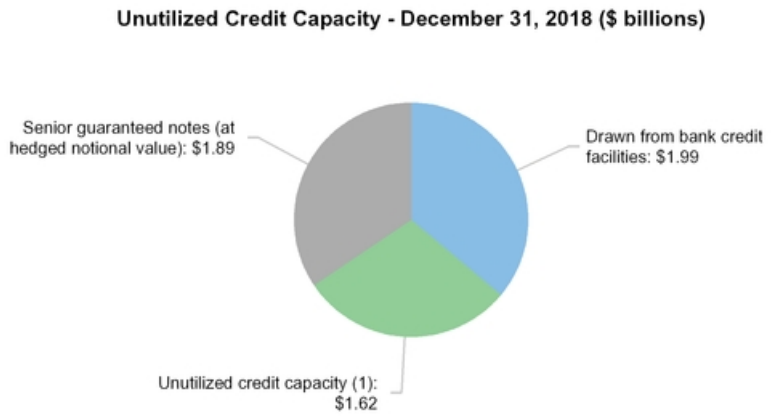
Capitalization Table ($ millions, except share, per share, ratio and percent amounts)	**December 31, 2018**	December 31, 2017
Net debt [1]	**4,011.3**	4,024.9
Shares outstanding	**550,151,561**	545,794,384
Market price at end of year (per share)	**4.14**	9.58
Market capitalization [1]	**2,277.6**	5,228.7
Enterprise value [1]	**6,288.9**	9,253.6
Net debt as a percentage of enterprise value	**64**	43
Adjusted funds flow from operations [1] [2]	**1,741.2**	1,728.8
Net debt to adjusted funds flow from operations [1]	**2.3**	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.

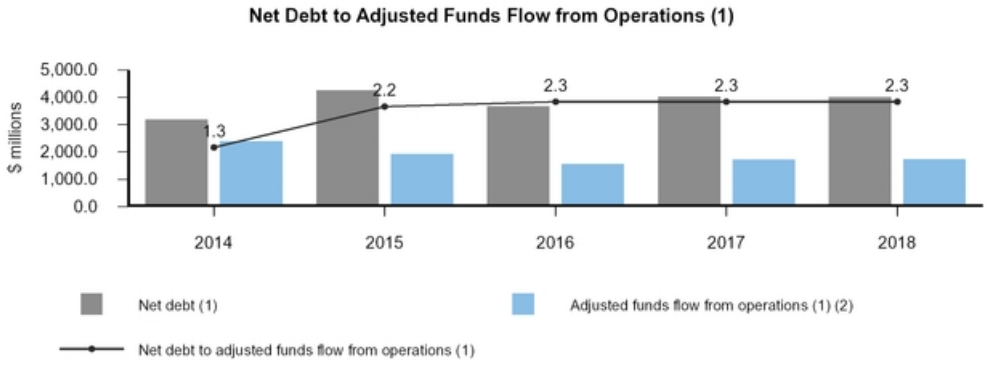
At December 31, 2018, Crescent Point's enterprise value was $6.29 billion and the Company was capitalized with 36 percent equity compared to $9.25 billion and 57 percent at December 31, 2017, respectively. The Company's net debt to adjusted funds flow from operations ratio at December 31, 2018 remained consistent at 2.3 times compared to December 31, 2017.

Exhibit 24



(1) Includes cash of $15.3 million.

Exhibit 25



(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 credit facilities of $3.60 billion, including a $3.50 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 date of the syndicated unsecured credit facility and the unsecured operating credit facility is June 10, 2021. Both of these facilities constitute revolving credit facilities and are extendible annually. As at December 31, 2018, the Company had approximately $1.99 billion drawn on bank credit facilities, including $8.0 million outstanding pursuant to letters of credit, leaving unutilized borrowing capacity of approximately $1.62 billion including cash of $15.3 million.

The Company has made private offerings of senior guaranteed notes raising total gross proceeds of US$1.48 billion and Cdn$277.0 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, 2018 which are listed in the table below:

Covenant Description	Maximum Ratio	**December 31, 2018**
Senior debt to adjusted EBITDA (1) (2)	3.5	**2.2**
Total debt to adjusted EBITDA (1) (3)	4.0	**2.2**
Senior debt to capital (2) (4)	0.55	**0.42**

(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.

Crescent Point's budgeted capital expenditure guidance for 2019 is $1.20 billion to $1.30 billion, excluding any net land and property acquisitions, with average 2019 production forecast at 170,000 boe/d to 174,000 boe/d.

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, 2018, Crescent Point had 550.2 million common shares issued and outstanding compared to 545.8 million common shares at December 31, 2017. The increase of 4.4 million shares relates to shares issued pursuant to the Restricted Share Bonus Plan.

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 is due to expire on January 24, 2020.

As of the date of this report, the Company has purchased, for cancellation, 1,284,400 common shares for total consideration of $5.0 million.

Contractual Obligations and Commitments

The Company has assumed various contractual obligations and commitments in the normal course of operations. 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 leases (building, vehicle and equipment) (1)	35.3	64.5	54.3	194.5	348.6
Senior guaranteed notes (2)	156.9	486.7	767.0	843.1	2,253.7
Bank credit facilities (3)	108.2	2,128.7	—	—	2,236.9
Transportation commitments	16.3	24.8	22.7	26.2	90.0
Total contractual commitments	316.7	2,704.7	844.0	1,063.8	4,929.2

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

(2) 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.

(3) These amounts include interest based on debt outstanding and interest rates effective as at December 31, 2018. The current maturity date of the Company's facilities is June 10, 2021. The Company expects that the facilities will be renewed and extended prior to their maturity dates.

Off Balance Sheet Arrangements

The Company has off-balance sheet financing arrangements consisting of various lease agreements which are entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2018. All of the lease agreement amounts have been reflected in the Contractual Obligations and Commitments table above.

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, 2018. 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 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 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 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 a positive or negative impact on Crescent Point's business. Financial risks the Company is exposed to include: marketing production at an acceptable price given market conditions; 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 Crescent Point is exposed to 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, 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; 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 uncertainties related to oil and gas interests and operations on tribal lands.

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.

In November 2015, the Province of Alberta released its Climate Leadership Plan which will impact businesses that contribute to carbon emissions in Alberta. The plan's four key areas include imposing carbon pricing that is applied across all sectors, starting at $20 per tonne on January 1, 2017 and moving to $30 per tonne on January 1, 2018, and a 45 percent reduction in methane emissions by the oil and gas sector by 2025. Prior to 2023, the plan is expected to have a minimal impact on the Company's results of operations as less than 10% of the Company's total production is from properties located in Alberta and the carbon levy exemption is available for fuel that is used, flared, or vented in a production process and sold to a consumer for use in an oil and gas production process. The Company continues to monitor developments in this plan for periods after 2023 and will evaluate the expected impact on its results of operations.

On June 21, 2018, the Government of Canada brought into force a pan-Canadian approach to the pricing of greenhouse gas emissions under the Greenhouse Gas Pollution Pricing Act ("GGPPA"). Previously, the federal government provided all Canadian provinces and territories a year to introduce their own carbon pricing models of either a cap and trade program or a carbon tax meeting a prescribed standard. For provinces that have failed to do so, including Saskatchewan, the federal government will begin to levy its own carbon tax on a broad set of emission sources on April 1, 2019. The initial carbon tax is $20 per tonne of GHG emissions and will increase by $10 per tonne per year until it reaches $50 per tonne in 2022. The federal government also has a greenhouse gas 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.

On January 31, 2019, the Supreme Court of Canada released its decision in Orphan Well Association v Grant Thornton Ltd., 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 Alberta Energy Regulator (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 a recent Supreme Court of Canada 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 a great deal of 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.

Refer to the Company's Annual Information Form for the year ended December 31, 2018 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

In the current accounting period, the Company adopted the following changes to IFRS:

- IFRS 9 *Financial Instruments* - IFRS 9 was amended in July 2014 to include guidance to assess and recognize impairment losses on financial assets based on an expected loss model. The adoption of this amendment did not have a material impact on the valuation of its financial assets. The Company had previously early adopted IFRS 9 with a date of initial application of January 1, 2010 and the amendment to IFRS 9 which presented a new hedge accounting model.
- IFRS 15 *Revenue from Contracts with Customers*- The Company reviewed contracts with customers for its major revenue streams and concluded that the adoption of IFRS 15 did not have a material impact on the consolidated financial statements. The adoption of IFRS required the Company to expand its disclosures in the notes to the consolidated financial statements, including the disaggregation of revenue streams by product type.

In future accounting periods, the Company will adopt the following IFRS:

IFRS 16 *Leases*

IFRS 16 was issued January 2016 and replaces IAS 17*Leases* and IFRIC 4 *Determining Whether an Arrangement Contains a Lease*. The standard introduces a single lessee accounting model for leases with required recognition of assets and liabilities for most leases, where the Company is acting as a lessee. The adoption of IFRS 16 for lessees eliminates the dual classification model of leases as either operating leases or finance leases, effectively treating almost all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from recognition and will continue to be treated as operating leases. There is no significant impact from the adoption of IFRS 16 for lessors as the dual classification model of leases and the accounting for lessors remains virtually unchanged. The standard is effective for fiscal years beginning on or after January 1, 2019 with early adoption permitted if the Company is also applying IFRS 15. The standard is required to be adopted either retrospectively or using a modified retrospective approach.

On January 1, 2019, the Company adopted IFRS 16 using the modified retrospective approach. 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 for onerous contracts instead of re-assessing the ROU asset for impairment on January 1, 2019.

The Company has completed a detailed assessment on the impact of the standard on the consolidated financial statements. A number of leases have been identified with the most significant impact being the recognition of lease obligations on operating leases for office space and the corresponding ROU assets. 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 will record accretion expense on the lease liability and depreciation expense on the ROU asset and the associated ROU asset will be 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.

Adoption of the new standard will result in the recognition of lease liabilities of approximately $220.0 million.

Outstanding Common Shares Data

As of the date of this report, the Company had 549,327,416 common shares outstanding.

Selected Annual Information

($ millions, except per share amounts)	**2018**	2017	2016
Oil and gas sales	**3,887.5**	3,303.9	2,548.5
Average daily production			
Crude oil (bbls/d)	**140,298**	139,996	133,172
NGLs (bbls/d)	**19,805**	18,250	17,372
Natural gas (mcf/d)	**108,376**	106,599	103,321
Total (boe/d)	**178,166**	176,013	167,764
Net income (loss) [1]	**(2,616.9)**	(124.0)	(932.7)
Net income (loss) per share [1]	**(4.77)**	(0.23)	(1.81)
Net income (loss) per share - diluted [1]	**(4.77)**	(0.23)	(1.81)
Adjusted net earnings from operations [2]	**234.6**	100.0	88.5
Adjusted net earnings from operations per share [2]	**0.43**	0.18	0.17
Adjusted net earnings from operations per share – diluted [2]	**0.43**	0.18	0.17
Cash flow from operating activities	**1,748.0**	1,718.7	1,524.3
Adjusted funds flow from operations [2]	**1,741.2**	1,728.8	1,572.5
Adjusted working capital (deficiency) [2] [3]	**(208.2)**	(133.3)	(277.0)
Total assets	**12,730.4**	16,005.3	16,163.6
Total liabilities	**6,117.6**	6,842.4	6,572.4
Net debt [2]	**4,011.3**	4,024.9	3,677.1
Total long-term derivative liability	**—**	16.6	3.0
Weighted average shares - diluted (millions)	**550.2**	546.8	519.3
Capital expenditures [4]	**1,477.3**	1,856.5	1,399.9
Dividends declared	**198.5**	197.7	260.3
Dividends declared per share	**0.36**	0.36	0.50

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

(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, dividends payable and long-term compensation liablity, less cash, accounts receivable, prepaids and deposits and long-term investments.

(4) Capital expenditures exclude capitalized share-based compensation and include capital acquisitions and dispositions. Capital acquisitions and dispositions represent total consideration for the transactions including long-term debt, working capital assumed and acquired common shares, and excludes transaction costs.

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 2016 through 2018, primarily due to movement in the Cdn $ WTI benchmark price, fluctuations in corporate oil price differentials, numerous corporate and property acquisitions/dispositions and the Company's successful 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

	2018				2017			
($ millions, except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas sales	**791.6**	1,076.7	1,084.0	935.2	916.2	767.0	813.8	806.9
Average daily production								
Crude oil (bbls/d)	**140,281**	134,146	145,532	141,312	140,544	139,254	140,878	139,303
NGLs (bbls/d)	**20,210**	22,257	17,934	18,775	19,437	18,811	17,658	17,061
Natural gas (mcf/d)	**106,236**	107,231	110,110	109,983	113,963	108,021	102,471	101,791
Total (boe/d)	**178,198**	174,275	181,818	178,418	178,975	176,069	175,615	173,329
Net income (loss)	**(2,390.5)**	30.5	(166.2)	(90.7)	(56.4)	(270.6)	83.6	119.4
Net income (loss) per share	**(4.35)**	0.06	(0.30)	(0.17)	(0.10)	(0.50)	0.15	0.22
Net income (loss) per share – diluted	**(4.35)**	0.06	(0.30)	(0.17)	(0.10)	(0.50)	0.15	0.22
Adjusted net earnings (loss) from operations [(1)]	**(16.3)**	84.8	102.7	63.4	(35.1)	33.7	39.5	61.9
Adjusted net earnings (loss) from operations per share [(1)]	**(0.03)**	0.15	0.19	0.12	(0.06)	0.06	0.07	0.11
Adjusted net earnings (loss) from operations per share – diluted [(1)]	**(0.03)**	0.15	0.19	0.12	(0.06)	0.06	0.07	0.11
Cash flow from operating activities	**359.1**	474.1	452.8	462.0	449.6	437.0	415.9	416.2
Adjusted funds flow from operations [(1)]	**337.3**	474.7	500.3	428.9	494.7	389.0	418.0	427.1
Adjusted working capital (deficiency) [(2)]	**(208.2)**	(139.9)	(90.4)	(339.8)	(133.3)	(259.1)	(171.6)	(202.0)
Total assets	**12,730.4**	15,948.9	16,174.7	16,481.6	16,005.3	15,945.1	16,419.2	16,568.8
Total liabilities	**6,117.6**	7,049.5	7,210.1	7,374.7	6,842.4	6,696.7	6,777.0	6,910.7
Net debt [(1)]	**4,011.3**	4,006.9	4,015.7	4,409.3	4,024.9	4,135.9	3,966.7	3,987.7
Total long-term derivative liability	**—**	17.9	35.3	17.4	16.6	8.8	—	—
Weighted average shares – diluted (millions)	**550.2**	551.1	551.0	548.4	546.9	546.2	546.1	546.2
Capital expenditures [(3)]	**275.0**	406.0	57.6	738.7	334.2	503.8	338.3	680.2
Dividends declared	**49.4**	49.8	49.7	49.6	49.5	49.4	49.4	49.4
Dividends declared per share	**0.09**	0.09	0.09	0.09	0.09	0.09	0.09	0.09

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

(3) Capital expenditures exclude capitalized share-based compensation and include capital acquisitions and dispositions. Capital acquisitions and dispositions represent total consideration for the transactions including long-term debt, working capital assumed and acquired common shares, and excludes transaction costs.

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, non-core 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, net impairments to PP&E recorded in the fourth quarter of 2018 and third quarter of 2017, net recovery of PP&E recorded in the fourth quarter of 2017 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, non-core 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 pay monthly dividends.

Fourth Quarter Review

- Crescent Point achieved production averaging 178,198 boe/d in the fourth quarter of 2018, an increase of two percent from third quarter 2018. Strong fourth quarter production growth supported annual average production of 178,166 boe/d. Production in fourth quarter of 2018 was weighted 90 percent towards crude oil and liquids.

- The decrease in WTI benchmark prices and wider Canadian oil differentials in the fourth quarter of 2018 negatively impacted cash flows and earnings. The Company's corporate crude oil differential relative to Cdn$ WTI for the fourth quarter of 2018 was $23.34 per bbl compared to $10.74 per bbl in third quarter 2018. As a result, adjusted funds flow from operations totaled $337.3 million in fourth quarter 2018, a decrease of 29 percent from third quarter 2018 and adjusted net loss totaled $16.3 million compared to adjusted net earnings of $84.8 million in third quarter 2018.

- The Company realized cost improvements in Q4 2018, with lower G&A and operating expenses.

- During the fourth quarter of 2018, the Company spent $278.4 million on drilling and development activities, drilling 172 (139.6 net) wells with a 99.6 percent success rate. Crescent Point also spent $28.8 million on land, seismic and facilities, for total development capital expenditures of $307.2 million.

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, 2018.

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, 2018, 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, 2018 based on the COSO Framework. Based on this evaluation, Management concluded that as of December 31, 2018, Crescent Point maintained effective ICFR.

The effectiveness of Crescent Point's ICFR as of December 31, 2018 was audited by PricewaterhouseCoopers LLP, as reflected in their report for 2018. There were no changes in Crescent Point's ICFR during the year ended December 31, 2018 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.

Health, Safety and Environment Policy

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

- Complying with government regulations and standards;

- Conducting operations consistent with industry codes, practices and guidelines;

- Ensuring prompt, effective response and repair to emergency situations and environmental incidents;
- Providing training to employees and contractors to ensure compliance with Company safety and environmental policies and procedures;
- Promoting the aspects of careful planning, good judgment, implementation of the Company's procedures, and monitoring Company activities;
- Communicating openly with members of the public regarding our activities; and
- Amending the Company's policies and procedures as may be required from time to time.

Crescent Point believes that all employees have a vital role in achieving excellence in environmental, health and safety performance. This is best achieved through careful planning and the support and active participation of everyone involved.

As part of Crescent Point's ongoing commitment to reduce emissions, the Company contributed to a climate change initiatives fund directed to environmental initiatives. To date, $65.3 million has been contributed towards emissions reduction and $51.2 million has been expended to reduce emissions and to meet and exceed provincial and federal targets. In 2018, the Company spent a total of $2.4 million on emissions reduction, primarily on upgrading facilities in Saskatchewan. These upgrades have reduced the Company's emissions, which continue to meet or fall below provincial and federal emission limits.

Outlook

Crescent Point's guidance for 2019 is as follows:

Production	
Total average annual production (boe/d)	170,000 to 174,000
% Oil and NGLs	91%
Total capital expenditures ($ millions) (1) (2)	$1,200 to $1,300
Drilling and development (%)	90%
Facilities and seismic (%)	10%

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

(2) Based on US$50.00/bbl WTI, $0.75 US/CAD, MSW differential of ~US$8.75/bbl and WCS differential of ~US$18.00/bbl for 2019.

The Company is currently exploring further disposition opportunities, including certain upstream and infrastructure assets. Crescent Point will be disciplined and flexible during its divestiture process to ensure appropriate asset values are realized for shareholders.

Additional information relating to Crescent Point, including the Company's December 31, 2018 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”, "payout ratio", “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 excluded as the Company has a voluntary reclamation fund to fund decommissioning costs. 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)	**2018**	2017	% Change
Cash flow from operating activities	**1,748.0**	1,718.7	2
Changes in non-cash working capital	**(37.2)**	(18.7)	99
Transaction costs	**5.1**	3.7	38
Decommissioning expenditures	**25.3**	25.1	1
Adjusted funds flow from operations	**1,741.2**	1,728.8	1

Adjusted net earnings from operations is calculated based on net income before amortization of 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)	**2018**	2017	% Change
Net income (loss)	**(2,616.9)**	(124.0)	2,010
Amortization of E&E undeveloped land	**157.2**	134.3	17
Impairment	**3,705.9**	203.6	1,720
Unrealized derivative (gains) losses	**(439.4)**	163.6	(369)
Unrealized foreign exchange (gain) loss on translation of hedged US dollar long-term debt	**254.2**	(201.2)	(226)
Unrealized loss on long-term investments	**16.2**	3.4	376
Gain on sale of long-term investments	**(0.7)**	—	—
Net (gain) loss on capital dispositions	**129.1**	(31.1)	(515)
Deferred tax relating to adjustments	**(971.0)**	(48.6)	1,898
Adjusted net earnings from operations	**234.6**	100.0	135

Payout ratio is calculated on a percentage basis as dividends declared divided by adjusted funds flow from operations. Payout ratio is used by management to monitor the dividend policy and the amount of adjusted funds flow from operations retained by the Company for capital reinvestment.

Net debt is calculated as long-term debt plus accounts payable and accrued liabilities, dividends payable 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)	**2018**	2017	% Change
Long-term debt [1]	**4,276.7**	4,111.0	4
Accounts payable and accrued liabilities	**532.9**	613.3	(13)
Dividends payable	**16.5**	16.8	(2)
Long-term compensation liability [2]	**10.0**	22.9	(56)
Cash	**(15.3)**	(62.4)	(75)
Accounts receivable	**(322.6)**	(380.2)	(15)
Prepaids and deposits	**(4.6)**	(4.5)	2
Long-term investments	**(8.7)**	(72.6)	(88)
Excludes:			
Unrealized foreign exchange on translation of US dollar long-term debt	**(473.6)**	(219.4)	116
Net debt	**4,011.3**	4,024.9	—

(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”, “well positioned” 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 objective to manage net debt to adjusted funds flow from operations to be well positioned to maximize shareholder return;
- 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 and the ability to fund dividends;
- Crescent Point’s 2019 average production and capital expenditure guidance;
- The Company's future disposition opportunities for certain upstream and infrastructure assets;
- Management's belief that the Company is well positioned to execute its business strategy;
- How the Company expects to finance its working capital deficiency and ongoing working capital requirements; and
- Expected adoption of new accounting policies.

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, 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 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 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; 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, 2018, 2017, 2016, 2015, and 2014 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

Robert Heinemann, Chairman

Rene Amirault [4]

Peter Bannister [3] [4]

Laura Cillis [1] [2]

John Dielwart [6]

Ted Goldthorpe [1] [5]

Mike Jackson [1] [2] [5]

Francois Langlois [3] [4] [5]

Barbara Munroe [2] [5]

Gerald Romanzin [1] [3]

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] Member effective March 7, 2019

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

Derek Christie
Senior Vice President, Exploration and Corporate Development

Mark Eade
Senior Vice President, General Counsel and Corporate Secretary

Scott Tuttle
Senior Vice President, Human Resources and Corporate Services

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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:

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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 7, 2019

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 7, 2019

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, 2018, 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 7, 2019

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, 2018, 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 7, 2019

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, 2018 of Crescent Point Energy Corp. of our report dated March 6, 2019, 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 6, 2019 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 in this Annual Report on Form 40-F, which is incorporated by reference in such Registration Statements.

/s/ PricewaterhouseCoopers LLP
Chartered Professional Accountants
Calgary, Alberta
March 6, 2019

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

March 6, 2019

We refer to our report dated February 13, 2019 and effective December 31, 2018, 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, 2018 dated March 6, 2019, 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 6, 2019

We refer to our report dated January 21, 2019 and effective December 31, 2018, 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, 2018 dated March 6, 2019, 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, 2018

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, 2018 and 2017, 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, 2018 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, 2016	288,422	34,267	181,042	352,862	24,824	2,895	37,743	34,009	313,246	37,161	218,785	386,872
Revisions of previous estimates	74,694	15,637	67,964	101,658	10,297	1,461	21,667	15,369	84,990	17,098	89,631	117,027
Improved recovery	3,892	1,564	3,868	6,101	—	—	—	—	3,892	1,564	3,868	6,101
Purchases of reserves in place	1,104	313	886	1,565	12,069	1,527	17,635	16,535	13,173	1,840	18,521	18,100
Extensions and discoveries	9,723	1,091	3,907	11,465	6,850	427	6,650	8,385	16,573	1,518	10,557	19,850
Production	(37,982)	(5,337)	(27,252)	(47,861)	(5,648)	(640)	(7,016)	(7,458)	(43,630)	(5,978)	(34,269)	(55,319)
Sales of reserves in place	(12,129)	(97)	(1,141)	(12,416)	(532)	(81)	(705)	(731)	(12,661)	(178)	(1,846)	(13,147)
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
Net Proved Developed Reserves												
December 31, 2016	208,214	24,905	134,032	255,457	17,003	2,298	24,586	23,399	225,217	27,203	158,618	278,856
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
Net Proved Undeveloped Reserves												
December 31, 2016	80,208	9,362	47,010	97,405	7,822	597	13,157	10,611	88,030	9,958	60,167	108,016
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

(1) Numbers may not add due to rounding.

Revisions of previous estimates - 2017

In 2017, total proved reserves increased by 68 MMboe in Canada and 14 MMboe in the United States due to increases in constant pricing for crude oil, natural gas and NGL constituents at December 31, 2017, compared to December 31, 2016. In Canada, positive technical revisions on natural gas of 21 MMcf and associated NGL constituents of 9 MMbbls were realized primarily due to increased recoveries from the Company's Viewfield and Flat Lake areas. Revisions of previous estimates also include reserves added through development and infill drilling, representing 15 MMboe in Canada and 2 MMboe in the United States.

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).

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).

Purchases of Reserves in Place

Through a number of property acquisitions in 2017, the Company acquired assets within its core operating areas in North Dakota and Utah. These acquisitions were offset by various non-core dispositions in Canada, as well as the disposition of the Company's minor interests in Colorado.

Extensions and Discoveries

In 2017, the Company realized extensions of 8 MMboe in the United States, primarily due to the success of step out horizontal well drilling in the Uinta Basin. There were no discoveries in 2017.

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

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

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	**2018**	**2017**
WTI at Cushing Oklahoma ($US/bbl)	65.55	51.30
Edmonton ($Cdn/bbl)	70.32	63.28
Exchange Rate ($US/$Cdn)	0.7758	0.7681
AECO/NIT Spot ($Cdn/MMBTU)	1.46	2.34
Henry Hub NYMEX ($US/MMBTU)	3.02	3.07

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, 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.

December 31, 2017 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Future cash inflows	20,515	3,111	23,626
Future production costs	(8,893)	(1,339)	(10,232)
Future development costs and asset retirement obligations [2]	(3,014)	(601)	(3,615)
Future income taxes [3]	(113)	(20)	(133)
Future net cash flows	8,496	1,151	9,646
Deduct: 10% annual discount factor for timing of future cash flows	(3,075)	(437)	(3,513)
Standardized measure of future net cash flows	5,420	714	6,134

(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, 2017, the Company's Canadian and United States tax pools in Canadian dollars were approximately $8.7 billion and $3.3 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, 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	546	72	618
Net change in income taxes	(198)	(10)	(208)
All other changes [3]	(441)	(201)	(643)
Balance, end of year	6,076	1,282	7,357

(1) Numbers may not add due to rounding.

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

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

December 31, 2017 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Balance, beginning of year	3,383	215	3,598
Sales, net of production costs and royalties	(1,647)	(243)	(1,890)
Net change in prices and royalties related to forecast production	2,343	193	2,536
Development costs incurred during the period	1,298	384	1,682
Changes in estimated future development costs	(973)	(288)	(1,262)
Extensions, discoveries and improved recovery, net of related costs	185	19	204
Technical reserve revisions	1,141	99	1,240
Purchases of reserves in place	21	170	190
Sales of reserves in place	(164)	(8)	(172)
Accretion of discount	338	23	362
Net change in income taxes	(39)	10	(28)
All other changes	(466)	139	(327)
Balance, end of year	5,420	714	6,134

(1) Numbers may not add due to rounding.

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

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

As at December 31, 2017 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Proved properties	22,412	3,469	25,881
Unproved properties	1,585	720	2,305
Total capital costs	23,997	4,189	28,186
Accumulated depletion, amortization and impairment	(11,899)	(1,648)	(13,547)
Net capitalized costs	12,098	2,541	14,639

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

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.

Year ended December 31, 2017 (millions of Canadian dollars) [1]	**Canada**	**United States**	**Total**
Property acquisition costs [2]			
Proved properties	38	157	195
Unproved properties	5	112	117
Development costs [3]	1,298	384	1,682
Exploration costs	25	105	130
Total	1,366	758	2,124

(1) Numbers may not add due to rounding.

(2) Excludes disposition proceeds of $291.8 million and $18.4 million for proved and unproved properties, respectively.

(3) Costs incurred exclude capitalized administration.

Results of Operations From Crude Oil and Natural Gas Producing Activities

Year ended December 31, 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)

Year ended December 31, 2017 (millions of Canadian dollars)	**Canada**	**United States**	**Total**
Petroleum and natural gas revenues, net of royalties	2,458	373	2,831
Less:			
Operating expenses	685	122	807
Transportation expenses	126	8	134
Depletion, amortization and impairment	1,838	(106)	1,732
Accretion on decommissioning liability	28	2	30
Operating income (loss)	(219)	347	128
Income taxes (recovery)	(2)	—	(2)
Results of operations	(217)	347	130