Crescent Point

CRESCENT POINT ENERGY CORP.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2017

Dated February 28, 2018

Contents

SPECIAL NOTES TO READER

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

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

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

- corporate strategy and anticipated financial and operational performance;
- forecast prices and the expected impact of commodity price fluctuations on cash available to pay dividends;
- 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 2018;
- corporate and asset acquisitions and dispositions;
- drilling programs;
- expected location inventory development timing;
- the expected ongoing transition to horizontal wells in Utah and its 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 final terms of the Stock Option Plan and the approval of same by the Shareholders;
- expected decommissioning, abandonment, remediation and reclamation costs;
- our tax horizon;
- the potential impact of NAFTA re-negotiations;

- 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 carbon taxes;
- payment of monthly dividends;
- 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; and
- treatment under governmental regulatory regimes, including royalty regimes applicable to natural resources.

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, 2017, 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, 2017, 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; 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 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.

Netback is calculated on a per boe basis as oil and gas sales, less royalties, operating and transportation expenses and realized derivative gains and losses. Netback is a common metric used in the oil and gas industry and is 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 AIF, 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 US 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.

"**AIF**" means this annual information form of the Corporation dated February 28, 2018 for the year ended December 31, 2017.

"**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.

"**Coral Hill**" means Coral Hill Energy Ltd.

"**Coral Hill Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving Coral Hill and the Corporation, completed on August 14, 2015, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2015*".

"**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.

"**Legacy**" means Legacy Oil + Gas Inc.

"**Legacy Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving Legacy and the Corporation, completed on June 30, 2015, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2015*".

"**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, 2017.

"**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 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.

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

bbl	barrel
bbls	barrels
bbls/d	barrels per day
Mbbls	thousand barrels
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
Mcf/d	thousand cubic feet per day
Mcfe	thousand cubic feet of gas equivalent converting one barrel of oil to 6 Mcf of natural gas equivalent
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	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, 2017 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 oil and natural gas reserves in Western Canada and the United States.

We make monthly 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.

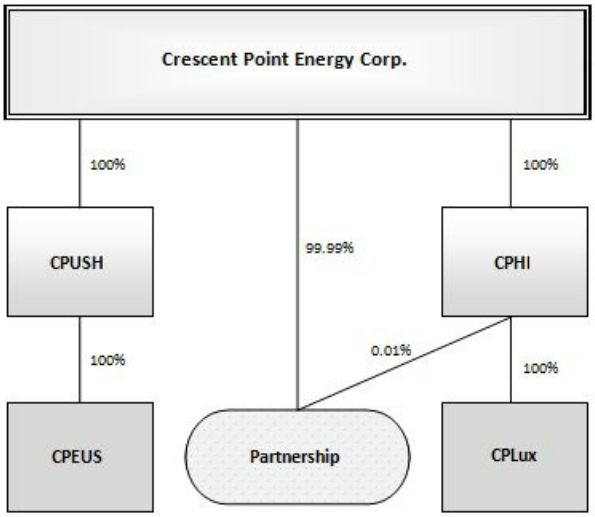
Relationships

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 February 28, 2018. 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.

2015

On March 10, 2015, the total amount available under the Corporation's syndicated credit facility and operating credit facility was increased to a total of $3.6 billion and the term was extended to June 8, 2018.

On April 22, 2015, the Corporation closed an offering of senior guaranteed notes in the United States and Canada on a private placement basis in aggregate principal amounts of US$250.0 million and $65.0 million, respectively. The terms of the U.S. notes range from 10 to 12 years with a weighted average term of 10.2 years and coupon rates ranging from 4.08% to 4.18% and the terms of the Canadian notes are 10 years with a coupon rate of 3.94%.

On June 16, 2015, the Corporation completed an equity offering of 23,160,000 Common Shares at $28.50 per Common Share for aggregate gross proceeds of approximately $660 million.

On June 30, 2015, the Corporation closed the Legacy Arrangement for total consideration of approximately $1.5 billion, comprised of 18,229,428 Crescent Point Common Shares, cash consideration of $19.4 million and assumed debt. See "*Description of Our Business – Reorganizations*".

On July 20, 2015, the Corporation filed a short form base shelf prospectus for an aggregate offering amount not to exceed $2.5 billion. The prospectus allows Crescent Point to offer and issue common shares, subscription receipts, warrants, options and debt securities in Canada and the U.S. at any time during the 25-month period that the prospectus remains in place.

On August 12, 2015, the Corporation reduced its monthly dividend to $0.10 per share, effective with the August dividend payable on September 15, 2015. In addition, effective with the August dividend, the Corporation suspended the SDP and DRIP. See "*Additional Information Respecting Crescent Point – Share Dividend Plan*".

On August 14, 2015, the Corporation closed the Coral Hill Arrangement pursuant to which the Corporation acquired all of the remaining issued and outstanding shares of Coral Hill not already owned by the Corporation (as at August 14, 2015, Crescent Point had an 8.7% equity interest in Coral Hill) for total consideration of $243.8 million, comprised of 4,283,680 Crescent Point Common Shares, assumed debt and the historical cost of Crescent Point's previously held equity investment of $42.0 million. See "*Description of Our Business – Reorganizations*".

On November 5, 2015, Gregory T. Tisdale announced that he was stepping down from his role as Chief Financial Officer of the Corporation. Ken Lamont, then Crescent Point's Vice President, Finance and Treasurer, was appointed Chief Financial Officer effective January 1, 2016.

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 the Canadian portion of the Williston basin. 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 are expected to close during the first quarter of 2018.

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 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.

We pay monthly cash dividends to Shareholders from our net cash flow in accordance with our dividend policy. Our primary sources of cash flow are distributions from the Partnership. See "*Dividends*".

Strategy

We strive to create sustainable, value-added growth in reserves, production and cash flow through the execution of management's integrated strategy of acquiring, exploiting and developing high quality, long life, light and medium oil and natural gas properties.

We develop our properties through a detailed technical analysis of information including reservoir characteristics, petroleum initially in place, recovery factors and the applicability of enhanced recovery techniques. Our goal is to increase reserves and production in a cost effective manner through a number of techniques, including drilling infill and step-out wells, fracture stimulation of horizontal wells, re-completing existing wells and implementing waterflood or pressure support schemes.

Risk Management and Marketing

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

(a) world market forces, including world supply and consumption levels and the ability of the OPEC to set and maintain production levels and prices for crude oil;
(b) political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
(c) increases or decreases in crude oil differentials and their implications for prices received by us;
(d) 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;

(e) 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;
(f) availability, proximity and capacity of oil and gas gathering systems, pipeline and processing facilities, railcars and railcar loading facilities;
(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 existing net of royalty production on 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 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 US dollars and benchmark natural gas prices are hedged using financial AECO-based instruments transacted in Canadian dollars. Total financial oil and gas hedges in 2017 amounted to approximately 42% of annual production, net of royalties, consisting of approximately 42% of annual liquids production and approximately 42% of annual natural gas production, net of royalties. The primary objective of this strategy is to be well positioned to maximize shareholder return with long-term growth plus dividend income. The Corporation recorded a realized derivative gain on oil and gas hedge contracts of $101.2 million in 2017.

Refer to the annual financial statements for our commitments under all hedging agreements as at December 31, 2017.

In addition to hedging benchmark crude oil and natural gas prices with financial instruments, we have also mitigated crude oil basis risk by delivering a portion of our crude oil production into diversified refinery markets using rail transportation. Crescent Point operates four railcar loading facilities, serving its key producing areas of southeast Saskatchewan, southwest Saskatchewan, central Alberta 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.

Crescent Point also enters into physical delivery and derivative WTI price differential contracts which manage the spread between US$ WTI and various stream prices. The Corporation manages physical delivery contracts on a month-to-month spot and term contract basis. From January to December 2017, approximately 22,000 bbls/d of liquids production was contracted with fixed price differentials off WTI. As of December 31, 2017, approximately 13,600 bbls/d of liquids production for calendar 2018, 8,600 bbls/d of liquids production for calendar 2019, 5,000 bbls/d of oil production for calendar 2020 and 2021 and 2,000 bbls/d of oil production for calendar 2022 to 2028 was contracted with fixed priced differentials off WTI. By locking in the price differential on these volumes, we have been able to reduce our exposure to volatility in crude oil differentials.

We also mitigate risk by having a well-diversified marketing portfolio for 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 and mitigated by Crescent Point's Risk Management Committee and is governed by a Board-approved Risk Management and Counterparty Credit Policy that is reviewed by the board of directors on no less than an annual basis. 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 100 purchasers and its financial hedging portfolio consists of 16 counterparties. The Corporation's portfolio of counterparty exposures is reviewed monthly and approved by the Chief Financial Officer and/or a Vice President, Finance and the Vice President, Marketing and Innovation. Counterparty exposures are also reviewed on a quarterly basis by both the Risk Management Committee and the Audit Committee.

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.

Our oil and natural gas volumes are sold in the U.S., Alberta, British Columbia, Manitoba and Saskatchewan. Approximately 77% of our liquids volumes are sold in Saskatchewan, 14% in the U.S., 7% in Alberta, 2% in Manitoba and less than 1% in British Columbia. Approximately 56% of our natural gas volumes are sold in Saskatchewan, 23% in the U.S., 21% in Alberta and less than 1% in Manitoba.

Revenue Sources

For 2017, our commodity production mix was approximately 90% 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
2017	97%	3%
2016	97%	3%
2015	96%	4%

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.

Certain of our customers and potential customers are themselves exploring for oil and natural gas, and the results of such exploration efforts could affect our ability to sell or supply oil or gas to these customers in the future. Our ability to successfully bid on and acquire additional 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 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, 2017, the Corporation had 1,085 full-time permanent employees: 462 employees at our head office in Calgary, 84 employees at our Denver office, 469 field employees in Canada and 70 field employees in the U.S.

Reorganizations

On June 30, 2015, the Corporation closed the Legacy Arrangement for total consideration of approximately $1.5 billion, comprised of 18,229,428 Crescent Point Common Shares, cash consideration of $19.4 million and assumed debt. The assets acquired under the Legacy Arrangement increased the Corporation's position in southeast Saskatchewan.

On August 14, 2015, the Corporation closed the Coral Hill Arrangement, pursuant to which the Corporation acquired all of the remaining issued and outstanding shares of Coral Hill not already owned by the Corporation. Total consideration for the acquisition was $243.8 million, comprised of 4,283,680 Crescent Point Common Shares, assumed debt and the historical cost of Crescent Point's previously held equity investment of $42.0 million. The Coral Hill Arrangement consolidated the Corporation's position in the Swan Hills Beaverhill Lake resource play and provided the Corporation with full operatorship, control over pace of development and an increased position in the core of the play.

Voluntary Reclamation Fund

The Corporation has a voluntary reclamation fund to fund future decommissioning costs and environmental emissions reduction costs. From April 1, 2015 to December 31, 2015, the Corporation allocated $0.60 per boe of production. From January 1, 2017 to December 31, 2017, the Corporation allocated $0.35 per boe of production. Additional contributions can be made at the discretion of management.

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, 2017 contained in the consolidated report of GLJ dated February 15, 2018 (the "**Crescent Point Reserve Report**"). The Crescent Point Reserve Report evaluated, as at December 31, 2017, and summarizes our crude oil, NGL and natural gas reserves. 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, 2017 forecast price and cost assumptions. GLJ evaluated approximately 46 percent of the assigned total Proved plus Probable reserves and 35 percent of the total Proved plus Probable value discounted at 10 percent. Sproule evaluated approximately 54 percent of the assigned total Proved plus Probable reserves and 65 percent of the total Proved plus Probable value discounted at 10 percent. Sproule evaluated a majority of our Canadian Williston basin 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 a portion of the Canadian Williston basin assets in southeast Saskatchewan and Manitoba. GLJ also performed the evaluation of the Corporation's U.S. assets in the Williston basin including properties 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 any legislative impact of greenhouse gas emissions regarding carbon pricing of our ongoing and future operations. We have adopted a strategy to reduce these impacts on the environment which will in turn minimize any potential financial impacts. Crescent Point has modelled 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, 2017 as an operating cost per unit volume of production. The Corporation has assessed these carbon pricing levels at provincial levels using the current models for British Columbia, Alberta and Manitoba. As legislation was not finalized as of December 31, 2017, it was assumed that Saskatchewan would fall under the current Federal program starting in January 2019. It is further anticipated that the ongoing efforts by Crescent Point to limit and reduce the Corporation's greenhouse gas emissions on existing and future operations will result in reductions of overall costs into the future. As a result, the economic model capped these unit operating carbon pricing at various times into the future. The total impact of the carbon pricing in the reserve report as prepared by GLJ and Sproule, reflects a negative impact of 1,255.3 Mboe and $169.6 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	101,900	90,305	24,167	19,075	141,069	131,090	38,951	35,657	110,917	104,562	89,849	83,447	339,547	307,462
United States	1,043	852	—	—	38,179	31,663	5,073	4,149	56,277	47,297	293	271	53,724	44,592
Total	102,943	91,157	24,167	19,075	179,248	162,754	44,023	39,805	167,194	151,859	90,142	83,718	393,271	352,054
Proved Developed Non-Producing														
Canada	2,955	2,700	177	160	3,094	2,846	641	587	1,951	1,844	2,316	2,045	7,578	6,941
United States	6	5	—	—	869	716	115	94	3,050	2,495	3	2	1,499	1,231
Total	2,961	2,705	177	160	3,963	3,562	756	681	5,001	4,339	2,319	2,048	9,077	8,172
Proved Undeveloped														
Canada	37,676	34,622	1,991	1,631	78,513	73,774	15,769	14,505	56,600	52,985	18,679	16,939	146,495	136,187
United States	—	—	—	—	61,974	50,579	8,542	6,939	71,464	58,370	—	—	82,426	67,246
Total	37,676	34,622	1,991	1,631	140,487	124,353	24,311	21,444	128,064	111,354	18,679	16,939	228,922	203,433
Total Proved														
Canada	142,531	127,627	26,335	20,866	222,676	207,711	55,361	50,749	169,468	159,391	110,844	102,431	493,621	450,590
United States	1,049	857	—	—	101,023	82,959	13,729	11,182	130,791	108,162	296	273	137,649	113,070
Total	143,580	128,484	26,335	20,866	323,698	290,669	69,090	61,931	300,259	267,552	111,140	102,704	631,270	563,659
Total Probable														
Canada	79,797	71,492	7,237	5,753	129,610	119,133	29,298	26,664	87,940	82,071	54,593	49,384	269,698	244,952
United States	4,382	3,604	—	—	74,641	61,076	9,741	7,918	87,083	71,398	102	93	103,295	84,514
Total	84,179	75,096	7,237	5,753	204,252	180,209	39,039	34,583	175,023	153,469	54,695	49,477	372,993	329,466
Total Proved Plus Probable														
Canada	222,328	199,120	33,571	26,619	352,286	326,843	84,659	77,413	257,408	241,461	165,437	151,815	763,318	695,542
United States	5,431	4,461	—	—	175,664	144,035	23,470	19,100	217,873	179,560	397	366	240,944	197,583
Total	227,759	203,580	33,571	26,619	527,950	470,878	108,129	96,514	475,281	421,021	165,834	152,181	1,004,262	893,125

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	11,270	8,364	7,269	6,696	5,617	4,864	10,555	7,957	6,969	6,447	5,458	4,758
United States	1,569	1,217	1,074	997	849	744	1,528	1,190	1,053	979	836	734
Total	12,839	9,581	8,343	7,693	6,467	5,609	12,083	9,147	8,021	7,426	6,294	5,492
Proved Developed Non-Producing												
Canada	223	176	155	143	120	104	162	132	119	111	97	86
United States	33	25	22	20	16	14	31	24	21	19	16	13
Total	256	200	176	163	137	117	194	156	139	130	112	99
Proved Undeveloped												
Canada	3,792	2,592	2,091	1,821	1,307	949	2,753	1,842	1,463	1,259	871	603
United States	1,552	848	593	464	239	98	1,299	715	498	388	192	68
Total	5,344	3,441	2,684	2,286	1,545	1,047	4,052	2,557	1,961	1,647	1,064	672
Total Proved												
Canada	15,286	11,132	9,515	8,660	7,044	5,917	13,470	9,931	8,550	7,818	6,426	5,447
United States	3,153	2,090	1,688	1,481	1,104	856	2,858	1,929	1,571	1,386	1,044	816
Total	18,439	13,222	11,203	10,141	8,149	6,773	16,328	11,860	10,122	9,203	7,470	6,262
Total Probable												
Canada	10,821	6,248	4,847	4,180	3,046	2,344	7,868	4,522	3,492	3,001	2,168	1,655
United States	3,416	1,847	1,377	1,158	797	582	2,571	1,389	1,037	873	604	444
Total	14,237	8,095	6,224	5,338	3,843	2,926	10,439	5,911	4,528	3,874	2,773	2,100
Total Proved Plus Probable												
Canada	26,107	17,379	14,362	12,840	10,091	8,261	21,338	14,453	12,042	10,819	8,594	7,102
United States	6,569	3,937	3,065	2,639	1,901	1,438	5,429	3,318	2,608	2,259	1,648	1,260
Total	32,676	21,317	17,427	15,479	11,992	9,699	26,767	17,771	14,650	13,078	10,243	8,362

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	36,039	3,941	13,159	2,773	880	15,286	1,816	13,470
United States	9,944	2,304	2,789	1,578	120	3,153	296	2,858
Total	45,983	6,245	15,948	4,351	1,000	18,439	2,111	16,328
Proved Plus Probable								
Canada	58,709	6,475	20,521	4,499	1,107	26,107	4,769	21,338
United States	18,613	4,358	5,109	2,409	169	6,569	1,141	5,429
Total	77,322	10,833	25,630	6,908	1,275	32,676	5,909	26,767

Notes:
(1) Numbers may not add due to rounding.
(2) Saskatchewan Capital Resource Surcharge in Canada and 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]	2,641	30.5	$18.39	$3.06
Heavy Crude Oil[1]	331	3.8	$15.73	$2.62
Tight Oil[3]	5,584	64.5	$20.53	$3.42
Natural Gas Liquids	—	—	—	—
Shale Gas[4]	—	—	—	—
Conventional Natural Gas[2]	103	1.2	$7.45	$1.24
Total Canada	8,660	100.0	$19.22	$3.20
UNITED STATES				
Light and Medium Crude Oil[1]	13	0.9	$15.01	$2.50
Heavy Crude Oil[1]	—	—	—	—
Tight Oil[3]	1,460	98.6	$13.17	$2.20
Natural Gas Liquids	—	—	—	—
Shale Gas[2]	8	0.5	$6.08	$1.01
Conventional Natural Gas[2]	<1	<0.1	$3.79	$0.63
Total United States	1,481	100.0	$13.10	$2.18
TOTAL				
Light and Medium Crude Oil[1]	2,654	26.2	$18.37	$3.06
Heavy Crude Oil[1]	331	3.3	$15.73	$2.62
Tight Oil[3]	7,044	69.5	$18.40	$3.07
Natural Gas Liquids	—	—	—	—
Shale Gas[2][4]	8	<0.1	$6.08	$1.01
Conventional Natural Gas[2]	104	1.0	$7.44	$1.24
Total Proved	10,141	100.0	$17.99	$3.00

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]	3,973	30.9	$17.44	$2.91
Heavy Crude Oil[1]	394	3.1	$14.68	$2.45
Tight Oil[3]	8,355	65.1	$19.72	$3.29
Natural Gas Liquids	—	—	—	—
Shale Gas[4]	—	—	—	—
Conventional Natural Gas[2]	118	0.9	$6.87	$1.14
Total Canada	12,840	100.0	$18.46	$3.08
UNITED STATES				
Light and Medium Crude Oil[1]	25	0.9	$5.58	$0.93
Heavy Crude Oil[1]	—	—	—	—
Tight Oil[3]	2,604	98.7	$13.60	$2.27
Natural Gas Liquids	—	—	—	—
Shale Gas[2]	9	0.4	$5.83	$0.97
Conventional Natural Gas[2]	<1	<0.1	$3.71	$0.62
Total United States	2,639	100.0	$13.36	$2.23
TOTAL				
Light and Medium Crude Oil[1]	3,998	25.8	$17.21	$2.87
Heavy Crude Oil[1]	394	2.5	$14.68	$2.45
Tight Oil[3]	10,959	70.8	$17.82	$2.97
Natural Gas Liquids	—	—	—	—
Shale Gas[2][4]	9	0.1	$5.83	$0.97
Conventional Natural Gas[2]	118	0.8	$6.86	$1.14
Total Proved Plus Probable	15,479	100.0	$17.33	$2.89

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, license or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

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

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

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

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

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

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

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

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

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

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

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

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

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

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

(aa) "**well abandonment and reclamation costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system and 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, 2017 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										
2018	3.25	2.85	55.00	65.44	67.72	48.73	26.06	0.0%	0.0%	0.790
2019	3.50	3.11	65.00	74.51	75.61	55.49	32.84	2.0%	2.0%	0.820
2020	4.00	3.65	70.00	78.24	78.82	57.65	35.41	2.0%	2.0%	0.850
2021	4.08	3.80	73.00	82.45	82.35	60.12	37.85	2.0%	2.0%	0.850
2022	4.16	3.95	74.46	84.10	84.07	61.32	39.29	2.0%	2.0%	0.850
2023	4.24	4.05	75.95	85.78	85.82	62.55	40.25	2.0%	2.0%	0.850
2024	4.33	4.15	77.47	87.49	87.61	63.80	41.23	2.0%	2.0%	0.850
2025	4.42	4.25	79.02	89.24	89.43	65.07	42.23	2.0%	2.0%	0.850
2026	4.50	4.36	80.60	91.03	91.29	66.37	43.26	2.0%	2.0%	0.850
2027	4.59	4.46	82.21	92.85	93.19	67.70	44.30	2.0%	2.0%	0.850
2028	4.69	4.57	83.85	94.71	95.12	69.06	45.36	2.0%	2.0%	0.850
2029+	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	+2%/yr	2.0%	2.0%	0.850

For the year ended December 31, 2017, the average realized sales prices before hedging were $58.65/bbl for light and medium crude oil, $51.02/bbl for heavy crude oil, $59.68/bbl for tight crude oil, $27.82/bbl for NGLs, $2.68/mcf for shale gas and $2.42/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, 2017 against such reserves as at December 31, 2016 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, 2016	158,179	94,499	252,677	22,816	7,329	30,145	221,705	130,906	352,611	46,665	25,288	71,952
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [(2)]	6,345	3,395	9,740	132	(132)	1	22,938	14,687	37,624	4,951	2,779	7,730
Technical Revisions [(3)]	6,226	(14,870)	(8,644)	5,136	75	5,211	2,177	(16,367)	(14,190)	9,212	497	9,709
Acquisitions [(8)]	585	1,436	2,020	42	8	51	1,045	396	1,440	434	752	1,186
Dispositions [(6)]	(12,810)	(5,423)	(18,233)	(21)	(63)	(84)	(273)	(357)	(630)	(108)	(103)	(211)
Economic Factors	387	759	1,146	30	19	50	520	347	866	41	85	127
Production	(16,380)	—	(16,380)	(1,801)	—	(1,801)	(25,435)	—	(25,435)	(5,834)	—	(5,834)
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

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, 2016	147,009	78,289	225,299	127,092	67,368	194,460	495,048	282,297	777,345
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2]	16,118	8,493	24,612	859	1,399	2,257	37,196	22,378	59,574
Technical Revisions [3]	24,266	1,384	25,651	(3,506)	(16,512)	(20,018)	26,210	(33,186)	(6,976)
Acquisitions [8]	904	339	1,243	437	1,477	1,914	2,329	2,895	5,224
Dispositions [6]	(459)	(701)	(1,160)	(936)	(579)	(1,515)	(13,444)	(6,160)	(19,604)
Economic Factors	324	135	459	(2,002)	1,441	(562)	699	1,473	2,172
Production	(18,695)	—	(18,695)	(11,100)	—	(11,100)	(54,416)	—	(54,416)
December 31, 2017	169,468	87,940	257,408	110,844	54,593	165,437	493,621	269,698	763,318

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, 2016	1,119	5,535	6,654	—	—	—	76,822	53,908	130,730	10,434	6,426	16,860
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [7]	—	—	—	—	—	—	16,384	17,299	33,683	1,550	2,300	3,850
Technical Revisions	796	388	1,184	—	—	—	2,068	(3,488)	(1,420)	929	65	995
Acquisitions [8]	—	—	—	—	—	—	14,615	5,681	20,295	1,870	813	2,683
Dispositions [6] [9]	(526)	(159)	(685)	—	—	—	(125)	(143)	(267)	(99)	(48)	(148)
Economic Factors	(29)	(1,382)	(1,411)	—	—	—	(1,570)	1,384	(186)	(127)	184	57
Production	(311)	-	(311)	—	—	—	(7,171)	—	(7,171)	(827)	—	(827)
December 31, 2017	1,049	4,382	5,431	—	—	—	101,023	74,641	175,664	13,729	9,741	23,470

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, 2016	100,492	60,664	161,156	169	73	242	105,151	75,992	181,144
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [7]	14,573	17,018	31,592	—	—	—	20,363	22,436	42,799
Technical Revisions	4,946	(1,993)	2,953	2,222	208	2,430	4,988	(3,331)	1,656
Acquisitions [8]	21,237	9,200	30,437	—	—	—	20,024	8,027	28,051
Dispositions [6] [9]	(77)	(105)	(182)	(664)	(202)	(865)	(873)	(401)	(1,274)
Economic Factors	(2,678)	2,298	(380)	(20)	22	2	(2,176)	573	(1,603)
Production	(7,703)	—	(7,703)	(1,411)	—	(1,411)	(9,829)	—	(9,829)
December 31, 2017	130,791	87,083	217,873	296	102	397	137,649	103,295	240,944

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, 2016	159,298	100,034	259,331	22,816	7,329	30,145	298,527	184,814	483,341	57,099	31,714	88,813
Discoveries	—	—	—	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2] [7]	6,345	3,395	9,740	132	(132)	1	39,322	31,986	71,307	6,501	5,080	11,581
Technical Revisions [3]	7,021	(14,481)	(7,460)	5,136	75	5,211	4,245	(19,855)	(15,610)	10,141	562	10,703
Acquisitions [8]	585	1,436	2,020	42	8	51	15,659	6,077	21,736	2,304	1,565	3,869
Dispositions [6] [9]	(13,335)	(5,582)	(18,917)	(21)	(63)	(84)	(398)	(500)	(898)	(207)	(152)	(359)
Economic Factors	358	(623)	(265)	30	19	50	(1,050)	1,731	680	(86)	269	184
Production	(16,691)	—	(16,691)	(1,801)	—	(1,801)	(32,607)	—	(32,607)	(6,661)	—	(6,661)
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

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, 2016	247,501	138,953	386,455	127,261	67,441	194,702	600,199	358,289	958,489
Discoveries	—	—	—	—	—	—	—	—	—
Extensions and Improved Recovery [2] [7]	30,692	25,512	56,203	859	1,399	2,257	57,559	44,814	102,373
Technical Revisions [3]	29,212	(608)	28,604	(1,284)	(16,304)	(17,588)	31,198	(36,517)	(5,320)
Acquisitions [8]	22,142	9,539	31,681	437	1,477	1,914	22,352	10,922	33,275
Dispositions [6] [9]	(536)	(806)	(1,342)	(1,600)	(781)	(2,380)	(14,317)	(6,561)	(20,878)
Economic Factors	(2,354)	2,433	79	(2,022)	1,463	(560)	(1,477)	2,046	569
Production	(26,398)	—	(26,398)	(12,511)	—	(12,511)	(64,245)	—	(64,245)
December 31, 2017	300,259	175,023	475,281	111,140	54,695	165,834	631,270	372,993	1,004,262

Notes:

(1) Numbers may not add due to rounding.

(2) The Corporation's development strategy in 2017 included both step-out and in-pool development drilling, mostly in the Bakken and Torquay resource plays in the Williston Basin; as well as the Upper and Lower Shaunavon resource plays in southwest Saskatchewan. These activities represented the majority of capital expenditures during the year. A portion of this growth also relates to Improved Recovery volumes being recognized by the qualified reserve evaluators due to ongoing waterflood activities.

(3) 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.

(4) Negative Tight Oil Technical Revisions on total proved plus probable reserves were recorded mostly in the Bakken and Torquay resource plays in the Williston Basin due to certain wells modestly underperforming the prior years' forecast, representing 1.8% of total Proved plus Probable Canadian reserves at December 31, 2016.

(5) Both Shale Gas and Natural Gas Liquids saw increases due to the qualified reserve evaluators recognizing increased gas volumes in their forecasts mostly in the Bakken and Torquay resource plays in the Williston Basin.

(6) Miscellaneous non-core dispositions were completed including conventional assets in the Williston Basin and minor assets in Southwest Saskatchewan.

(7) The Corporation's development strategy in 2017 included both step-out and in-pool development drilling, mostly in the Bakken and Three Forks resource plays in the Williston Basin; as well as a focus on horizontal well development of the Uinta Basin.

(8) Crescent Point completed multiple acquisitions in the Williston Basin and the Uinta Basin that included both top-up and areal expansion acquisitions that will support future organic growth.

(9) The Corporation disposed of all its assets in the DJ Basin of Colorado.

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 80% of the net undeveloped location count, as well as 80% of the net total future development capital.

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
2015	8,793	45,641	—	2,104	11,854	129,664	2,590	18,740	13,891	91,605	7,949	27,061	26,877	215,926
2016	3,164	43,998	—	2,006	9,944	132,529	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

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 72% of the net undeveloped location count, as well as 73% 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.

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
2015	14,585	58,775	—	1,803	16,008	106,175	2,906	14,524	13,363	64,188	7,930	34,032	37,048	197,647
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

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.

As circumstances change and additional data become 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, new geological or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions 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]		US [3]		Total	
Year	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable	Total Proved	Total Proved Plus Probable
2018	801	1,085	379	553	1,180	1,638
2019	772	1,158	415	591	1,187	1,749
2020	634	914	369	579	1,003	1,492
2021	240	808	215	371	456	1,179
2022	210	405	94	182	304	587
2023	8	12	49	67	57	80
2024	11	9	56	67	66	75
2025	7	7	—	—	7	7
2026	6	7	—	—	6	7
2027	6	6	—	—	6	6
2028	5	8	—	—	5	8
2029	5	6	—	—	5	6
Subtotal[1]	2,706	4,427	1,578	2,409	4,283	6,835
Remainder	68	72	—	—	68	72
Total[1]	2,773	4,499	1,578	2,409	4,351	6,908
10% Discounted	2,275	3,640	1,287	1,955	3,562	5,595

Notes:

(1) Numbers may not add due to rounding.

(2) In Canada, the Corporation drilled 691 (593.7 net) wells in 2017. For 2018, the Corporation has budgeted the drilling of 628 (573.4 net) wells representing a relatively constant development program. 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 that reflect the actual levels of both prior year drilling and current year budget plans. As a result, both the total Proved and total Proved plus Probable drilling schedule occur over a five year period. Only 2 (0.2 net) non-operated unit wells are scheduled in the sixth year. The remaining capital expenditures beyond the five year period relate to maintenance capital on existing wells and assets.

(3) In the United States, the Corporation is showing increasing capital spending trends over time, which is reflected in the qualified reserve evaluator drill schedule. Crescent Point drilled 103 (55.4 net) wells in 2017, while in 2018, the Corporation is budgeting the drilling of 101 (61.3 net) wells reflecting an increase in both net interest drills as well as an increased focus on horizontal drills in its resource based plays. 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 that reflect the actual levels of both prior year drilling and current year budget plans. As a result, both the total Proved and total Proved plus Probable drilling schedule occur over a seven year period. A small number of currently booked vertical locations in the Uinta basin extend beyond the five year period of time, representing 9.4 percent of the Corporation's total booked location inventory within the basin. Should the ongoing development across the Unita Basin continue to support widespread conversion to horizontal wells, the Corporation may replace many of the currently booked vertical locations with horizontal booked locations and horizontal drilled wells over time.

We estimate that our internally generated cash flow will be sufficient to fund the future development costs ("**FDC**") disclosed above. We typically have available three sources of funding to finance our capital expenditure program: Internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favourable terms. Debt financing is available to us at market rate plus an applicable margin based on our debt to cash flow ratio.

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, 2017.

In 2017, the Corporation continued to develop large resource play assets in Canada and the United States based on its knowledge-first strategy, including through improved technology, waterflood implementation, strategic acquisitions and non-core dispositions. The properties and assets discussed below account for a majority of the Proved plus Probable reserve bookings prepared by GLJ and Sproule for year-end 2017, and are representative of the high quality assets in the Corporation's portfolio.

Williston Basin

Crescent Point is the largest Canadian producer, and among the five largest producers, across this expansive basin, with current gross production exceeding 100,000 boe per day. The Bakken and Torquay resource plays in the Canadian portion of the Williston Basin extend south into North Dakota where the Torquay resource is equivalent to the United States Three Forks resource play. Crescent Point is able to utilize best practices and knowledge transfer, from both sides of the border, to optimize development of these resources.

The Corporation holds a large portfolio of assets in the Canadian portion of the Williston Basin. The basin includes the widespread Bakken resource play covering more than 1,000 sections of land in southeast Saskatchewan and the Saskatchewan Torquay resource play immediately north of the United States border that also covers in excess of 1,000 sections of land. In addition, Crescent Point has production interests in numerous conventional oil plays within the Williston Basin in Canada across the Mississippian period of producing formations. In the United States, the Corporation is focused on the Bakken and Three Forks resource plays where much of North Dakota's production is found. Across the Williston Basin, Crescent Point holds significant contiguous production and development rights over the large tracts of land where these plays exist. Production is a high quality light oil and is essentially exploited using both non-fractured and multi-fractured horizontal wells. The Corporation holds interests that are currently producing under primary, waterflood and enhanced recovery methods.

Crescent Point spent $734.5 million, representing 40.5 percent of its 2017 capital development program, on the Canadian portion of the Williston Basin including drilling 379 (325.1 net) additional wells; almost all being drilled horizontally. The Corporation also continued to focus on waterflood development and facility enhancements during the year. In the United States, the Corporation spent $133.1 million representing 7.3 percent of its 2017 capital development program, drilling 29 (19.2 net) horizontal wells.

At year-end 2017, the Corporation's total Proved plus Probable reserves in the Canadian portion of the Williston Basin were 453.2 MMboe, with 1,637 (1,521.8 net) locations booked to these reserves. In the United States portion of the Williston Basin, the Corporation had 108.9 MMboe of total Proved plus Probable reserves, including 358 (231.7 net) locations at year-end 2017. Combined, this represents 56.0 percent of the Corporation's total Proved plus Probable reserves. It is expected these locations will all be developed within five years. In addition, the independent qualified reserve evaluators have recognized 11.4 MMboe of incremental waterflood recoveries across the Canadian portion of the basin in the 2017 year-end total Proved plus Probable reserves assessment.

Crescent Point expects to spend a significant portion of the Corporation's capital in 2018 in the Williston Basin in Canada. The Corporation's total capital budget for the region is approximately $753.8 million, including drilling approximately 363 (337.9 net) wells. As in prior years, this program is designed to expand and diversify our asset base, expand waterflood development and develop our drilling inventory. In the United States portion of the Williston Basin, the Corporate expects to spend $267.1 million, including drilling approximately 47 (32.1 net) wells during 2018.

Southwest Saskatchewan

The southwest Saskatchewan region contains two focus resource plays that Crescent Point is developing. In the south end of the region is the Shaunavon resource area and, towards the central portion of the province, is the Viking resource basin. This region also contains several large mature fields that are under waterflood in Saskatchewan and a smaller group of assets held in east-central Alberta.

The Shaunavon resource play in southwest Saskatchewan includes two discrete formations; the Lower Shaunavon and Upper Shaunavon. 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. 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 having been successfully implemented as well. The Corporation has been developing these reservoirs using fracture stimulated horizontal wells and by implementing waterflood pilots that have continued to grow both production and reserves in the area.

The Viking light oil resource play is a shallow sandstone formation in west-central Saskatchewan and east-central Alberta containing high-quality light oil. Much of the conventional areas Viking zone has been developed over the past decades using vertical fractured wells using waterfloods on fairly tight well spacing. Development of the Viking resource in now focused on using horizontal fracture stimulated wells.

In 2017, the Corporation continued to develop the southwest Saskatchewan region by drilling 289 (248.7 net) wells, by applying improved technologies and through waterflood activities that enhance recoveries. Total capital spent on these activities was $391.6 million in 2017, representing 21.6 percent of the development capital budget.

As of year-end 2017, Crescent Point has booked total Proved plus Probable reserves of 220.4 MMboe in the southwest Saskatchewan region, representing 21.9 percent of the total Proved plus Probable reserves. The Corporation has 1,324 (1,073.8 net) locations booked to total Proved plus Probable reserves as of year-end 2017. Crescent Point expects to fully develop this location inventory within five years. The Corporation's independent qualified reserve evaluators have recognized additional total Proved plus Probable waterflood recoveries of 5.9 MMboe of incremental waterflood recoveries across the basin, in the 2017 year-end total Proved plus Probable reserves assessment.

In 2018, Crescent Point expects to spend $347.5 million of its capital budget in southwest Saskatchewan. During 2018, the Corporation expects to drill approximately 235 (206.8 net) wells and to continue to expand the waterflood projects within the Lower and Upper Shaunavon zones.

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. In 2017, Crescent Point continued to expand the development of the resource using both one-mile and two-mile horizontal well drilling technology to focus production on specific prolific zones including the Castle Peak, Uteland Butte and Wasatch within this expansive reservoir package. The Corporation is continuing its development of waterflood pilots and projects to evaluate this additional potential in the basin.

In 2017, Crescent Point spent $344.7 million of its capital budget in the area, including drilling 16 (4.3 net) vertical wells and 58 (31.9 net) horizontal wells, representing 19.0 percent of the development capital budget.

Total Proved plus Probable reserves in the Uinta Basin were 131.9 MMboe at year-end 2017 including 806 (445.9 net) Proved plus Probable booked locations. Of these locations, 100 (61.2 net) are horizontal locations. These reserves represent 13.1 percent of the Corporation’s total Proved plus Probable reserve bookings as of December 31, 2017. Crescent Point expects to fully develop this current horizontal location inventory within three years.

In 2018, Crescent Point expects to spend approximately $337.7 million in the area, including the drilling of 54 (29.2 net) operated horizontal wells.

Oil and Gas Wells[2]

Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Alberta	929	753	435	316
Saskatchewan	11,219	8,530	525	180
Manitoba	464	322	—	—
British Columbia	9	6	—	—
TOTAL CANADA	12,621	9,611	960	496
U.S.				
North Dakota	333	163	—	—
Montana	29	17	39	20
Utah	3,704	1,087	436	147
TOTAL U.S.	4,066	1,267	475	167
Total[1]	16,687	10,877	1,435	664

Non-Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Alberta	393	268	330	263
Saskatchewan	5,363	3,859	596	448
Manitoba	1	1	—	—
British Columbia	—	—	4	2
TOTAL CANADA	5,757	4,128	930	713
U.S.				
North Dakota	43	39	—	—
Montana	17	10	11	7
Utah	605	190	56	26
TOTAL U.S.	665	239	67	33
Total[1]	6,422	4,366	997	747

Notes:
(1) Numbers may not add due to rounding.
(2) 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 its Voluntary Reclamation Fund, to fund current and future decommissioning costs on a priority based system. Non-producing reserves represent only 1.4% 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, 2017		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
CANADA			
Alberta	797,290	754,270	79,568
Saskatchewan	1,339,633	1,297,859	251,627
Manitoba	37,597	37,088	14,058
British Columbia	38,408	23,225	4,796
Total	2,212,928	2,112,442	350,049
U.S.			
Montana	78,839	56,847	154
North Dakota	50,098	41,804	1,391
Utah	411,112	233,338	11,333
Total	540,049	331,989	12,878
Total	2,752,977	2,444,431	362,927

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, 2017, in each of Canada and the United States.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	673	577	12	11	685	588
Natural Gas wells	—	—	—	—	—	—
Service wells	6	6	—	—	6	6
Stratigraphic test	—	—	—	—	—	—
Dry Holes	—	—	—	—	—	—
Total	679	583	12	11	691	594

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	85	42	17	13	102	54
Natural Gas wells	—	—	—	—	—	—
Service wells	—	—	—	—	—	—
Stratigraphic Test	—	—	—	—	—	—
Dry Holes [(1)]	—	—	1	1	1	1
Total	85	42	18	14	103	55

Note:
(1) Following an operational issue, which resulted in partial abandonment of a well, an adjacent well was successfully drilled and completed by the Corporation.

For details on important exploration and development activities during 2017, 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 $12.0 billion at December 31, 2017 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, 2017. The total capital costs were approximately $1.8 billion in 2017.

($ millions)	Acquisition Costs [2]			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	38.1	4.8	25.0	1,297.9
U.S.	157.0	112.1	104.8	384.4
Total	195.1	116.9	129.8	1,682.3

Notes:
(1) Costs incurred exclude capitalized administration.
(2) Excludes disposition proceeds of $291.8 million and $18.4 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 2018 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							
Williston Basin	23,563	—	47,505	13,041	40,278	4,792	91,621
Southwest Saskatchewan	10,017	4,686	21,361	477	12,847	4,375	39,411
Alberta	8,411	—	394	3,027	255	19,415	15,110
Total CANADA[1]	41,990	4,686	69,260	16,545	53,381	28,581	146,141
U.S.							
Williston Basin	610	—	8,312	1,643	5,754	77	11,537
Uinta Basin	—	—	17,764	1,244	26,924	31	23,502
Total U.S.[1]	610	—	26,077	2,887	32,678	108	35,039
Total Corporate[1]	42,601	4,686	95,336	19,432	86,059	28,690	181,180

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

Production in Williston Basin and southwest Saskatchewan accounts for 57% and 22%, respectively, of the Corporation's Proved production estimate in 2018.

The Canadian portion of the Williston Basin region includes production volumes in the Viewfield area in southeast Saskatchewan that accounts for 31% of the Corporation's Proved production. The remaining areas in the Williston Basin represent small percentages of Proved production volume estimates.

The following table discloses, for each product type, the gross volume of production estimated by GLJ and Sproule for 2018 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							
Williston Basin	26,244	—	55,876	14,750	45,837	5,291	105,391
Southwest Saskatchewan	11,259	4,773	25,295	547	14,903	4,821	45,161
Alberta	10,479	—	444	3,583	288	22,855	18,363
Total CANADA[1]	47,981	4,773	81,615	18,881	61,027	32,967	168,916
U.S.							
Williston Basin	637	—	10,074	1,983	6,847	82	13,849
Uintah Basin	—	—	23,197	1,467	32,213	33	30,038
Total U.S.[1]	637	—	33,271	3,449	39,059	115	43,887
Total Corporate[1]	48,618	4,773	114,886	22,330	100,087	33,082	212,802

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

Production in Williston Basin and southwest Saskatchewan accounts for 56% and 21%, respectively, of the Corporation's total Proved plus Probable production estimate in 2018.

The Canadian portion of the Williston Basin region includes production volumes in the Viewfield area in southeast Saskatchewan that accounts for 29% of the Corporation’s Proved plus Probable production. The remaining areas in the Williston Basin represent small percentages of Proved plus Probable production volume estimates.

Production History

The following table discloses, on a quarterly and annual basis for the year ended December 31, 2017, 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, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	2017
CANADA					
Light and Medium Crude Oil (bbls/d)	49,025	44,761	43,501	42,310	44,877
Heavy Crude Oil (bbls/d)	5,113	4,891	4,874	4,862	4,934
Tight Oil (bbls/d)	69,546	72,109	67,176	69,938	69,686
NGLs (bbls/d)	15,416	15,310	16,114	17,073	15,983
Shale Gas (Mcf/d)	47,275	50,588	49,557	57,365	51,219
Conventional Natural Gas (Mcf/d)	33,322	28,066	30,775	29,514	30,410
Total (boe/d)	152,533	150,180	145,054	148,663	149,085
U.S.					
Light and Medium Crude Oil (bbls/d)	897	847	820	845	852
Heavy Crude Oil (bbls/d)	—	—	—	—	—
Tight Oil (bbls/d)	14,722	18,270	22,883	22,589	19,647
NGLs (bbls/d)	1,645	2,348	2,697	2,364	2,267
Shale Gas (Mcf/d)	20,903	19,047	22,484	21,954	21,104
Conventional Natural Gas (Mcf/d)	291	4,770	5,205	5,130	3,866
Total (boe/d)	20,796	25,435	31,015	30,312	26,928
TOTAL					
Light and Medium Crude Oil (bbls/d)	49,922	45,608	44,321	43,155	45,729
Heavy Crude Oil (bbls/d)	5,113	4,891	4,874	4,862	4,934
Tight Oil (bbls/d)	84,268	90,379	90,059	92,527	89,333
NGLs (bbls/d)	17,061	17,658	18,811	19,437	18,250
Shale Gas (Mcf/d)	68,178	69,635	72,041	79,319	72,323
Conventional Natural Gas (Mcf/d)	33,613	32,836	35,980	34,644	34,276
Total (boe/d)	173,329	175,615	176,069	178,975	176,013

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, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	2017
CANADA					
Prices Received – net of hedging	59.74	60.64	58.04	65.18	60.84
Royalties	(8.90)	(8.28)	(7.86)	(9.64)	(8.66)
Production Costs[1]	(13.20)	(14.52)	(14.90)	(14.49)	(14.25)
Transportation Costs[1]	(2.09)	(2.21)	(2.07)	(2.04)	(2.10)
Netback	35.55	35.63	33.21	39.01	35.83
U.S.					
Prices Received – net of hedging	54.91	53.52	50.83	59.28	54.67
Royalties	(14.91)	(14.48)	(11.94)	(15.70)	(14.28)
Production Costs[1]	(14.40)	(14.83)	(12.36)	(13.12)	(13.69)
Transportation Costs[1]	—	(0.86)	(1.13)	(0.99)	(0.73)
Netback	25.60	23.35	25.40	29.47	25.97
TOTAL					
Prices Received – net of hedging	59.65	60.51	57.90	65.07	60.73
Royalties	(9.00)	(8.40)	(7.93)	(9.76)	(8.77)
Production Costs[1]	(13.22)	(14.52)	(14.85)	(14.47)	(14.24)
Transportation Costs[1]	(2.05)	(2.19)	(2.05)	(2.02)	(2.08)
Netback	35.38	35.40	33.07	38.82	35.64

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, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	2017
CANADA					
Prices Received	49.74	49.97	49.18	55.23	51.02
Royalties	(13.38)	(12.33)	(12.86)	(13.33)	(12.98)
Production Costs[1]	(11.14)	(12.38)	(13.73)	(12.48)	(12.42)
Transportation Costs[1]	(2.47)	(1.24)	(1.65)	(1.86)	(1.81)
Netback	22.75	24.02	20.94	27.56	23.81
U.S.					
Prices Received	—	—	—	—	—
Royalties	—	—	—	—	—
Production Costs[1]	—	—	—	—	—
Transportation Costs[1]	—	—	—	—	—
Netback	—	—	—	—	—
TOTAL					
Prices Received	49.74	49.97	49.18	55.23	51.02
Royalties	(13.38)	(12.33)	(12.86)	(13.33)	(12.98)
Production Costs[1]	(11.14)	(12.38)	(13.73)	(12.48)	(12.42)
Transportation Costs[1]	(2.47)	(1.24)	(1.65)	(1.86)	(1.81)
Netback	22.75	24.02	20.94	27.56	23.81

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 Crude Oil

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	2017
CANADA					
Prices Received – net of hedging	60.44	60.78	61.04	66.69	62.25
Royalties	(6.43)	(7.27)	(6.38)	(6.21)	(6.58)
Production Costs[1]	(13.35)	(14.55)	(15.67)	(14.83)	(14.60)
Transportation Costs[1]	(3.08)	(3.18)	(2.94)	(3.24)	(3.11)
Netback	37.58	35.78	36.05	42.41	37.96
U.S.					
Prices Received – net of hedging	59.96	56.76	54.74	62.18	58.33
Royalties	(14.75)	(13.93)	(14.07)	(14.45)	(14.27)
Production Costs[1]	(15.72)	(15.73)	(13.32)	(13.76)	(14.45)
Transportation Costs[1]	(0.12)	(0.21)	(0.20)	(0.25)	(0.20)
Netback	29.37	26.89	27.15	33.72	29.41
TOTAL					
Prices Received – net of hedging	60.35	59.96	59.44	65.59	61.39
Royalties	(7.88)	(8.61)	(8.34)	(8.22)	(8.27)
Production Costs[1]	(13.77)	(14.79)	(15.07)	(14.57)	(14.56)
Transportation Costs[1]	(2.56)	(2.58)	(2.24)	(2.51)	(2.47)
Netback	36.14	33.98	33.79	40.29	36.09

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, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	March 31, 2017
CANADA					
Prices Received	24.48	24.27	25.45	33.62	27.14
Royalties	(1.75)	(2.51)	(1.94)	(2.90)	(2.29)
Production Costs[1]	(5.56)	(5.69)	(7.07)	(7.12)	(6.39)
Transportation Costs[1]	(0.38)	(0.42)	(0.64)	(0.37)	(0.45)
Netback	16.79	15.65	15.80	23.23	18.01
U.S.					
Prices Received	31.82	31.85	28.59	38.61	32.64
Royalties	(9.19)	(7.22)	(6.56)	(7.48)	(7.44)
Production Costs[1]	(8.37)	(8.82)	(7.18)	(8.58)	(8.18)
Transportation Costs[1]	(0.49)	(0.70)	(0.39)	(0.76)	(0.59)
Netback	13.77	15.11	14.46	21.79	16.43
TOTAL					
Prices Received	25.19	25.28	25.90	34.23	27.82
Royalties	(2.46)	(3.14)	(2.60)	(3.45)	(2.93)
Production Costs[1]	(5.83)	(6.11)	(7.08)	(7.29)	(6.62)
Transportation Costs[1]	(0.39)	(0.46)	(0.60)	(0.42)	(0.47)
Netback	16.51	15.57	15.62	23.07	17.80

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 – Shale Gas

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	2017
CANADA					
Prices Received - net of hedging	3.17	3.03	2.43	2.69	2.82
Royalties	(0.47)	(0.67)	(0.25)	(0.24)	(0.40)
Production Costs[1]	(0.79)	(0.81)	(0.65)	(0.57)	(0.70)
Transportation Costs[1]	(0.19)	(0.18)	(0.17)	(0.18)	(0.18)
Netback	1.72	1.37	1.36	1.70	1.54
U.S.					
Prices Received - net of hedging	3.65	3.55	3.00	3.27	3.35
Royalties	(1.22)	(0.84)	(0.72)	(0.48)	(0.81)
Production Costs[1]	(0.99)	(1.04)	(0.68)	(0.71)	(0.84)
Transportation Costs[1]	(0.53)	(0.80)	(0.47)	(0.59)	(0.59)
Netback	0.91	0.87	1.13	1.49	1.11
TOTAL					
Prices Received - net of hedging	3.31	3.17	2.61	2.85	2.97
Royalties	(0.70)	(0.72)	(0.40)	(0.30)	(0.52)
Production Costs[1]	(0.85)	(0.87)	(0.66)	(0.61)	(0.74)
Transportation Costs[1]	(0.29)	(0.35)	(0.27)	(0.29)	(0.30)
Netback	1.47	1.23	1.28	1.65	1.41

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, 2017	June 30, 2017	Sept. 30, 2017	Dec. 31, 2017	2017
CANADA					
Prices Received - net of hedging	3.22	3.06	2.05	2.19	2.63
Royalties[2]	0.27	(0.07)	(0.05)	0.30	0.12
Production Costs[1]	(0.80)	(0.82)	(0.55)	(0.46)	(0.66)
Transportation Costs[1]	(0.29)	(0.30)	(0.29)	(0.30)	(0.29)
Netback	2.40	1.87	1.16	1.73	1.80
U.S.					
Prices Received - net of hedging	2.09	4.12	3.47	3.39	3.62
Royalties	(0.52)	(0.71)	(0.61)	(0.60)	(0.64)
Production Costs[1]	(0.57)	(1.21)	(0.79)	(0.73)	(0.89)
Transportation Costs[1]	—	(0.95)	(0.94)	(0.47)	(0.77)
Netback	1.00	1.25	1.13	1.59	1.32
TOTAL					
Prices Received - net of hedging	3.21	3.21	2.26	2.37	2.74
Royalties[2]	0.26	(0.16)	(0.13)	0.17	0.03
Production Costs[1]	(0.80)	(0.87)	(0.58)	(0.50)	(0.68)
Transportation Costs[1]	(0.28)	(0.39)	(0.38)	(0.32)	(0.35)
Netback	2.39	1.79	1.17	1.72	1.74

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, 2017 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							
Williston Basin	26,502	—	46,625	13,345	41,817	4,451	94,183
Southwest Saskatchewan	10,837	4,934	22,983	349	9,380	6,422	41,737
Alberta	7,538	—	78	2,289	22	19,537	13,165
Total CANADA[1]	44,877	4,934	69,686	15,983	51,219	30,410	149,085
U.S.							
Williston Basin	807	—	6,215	1,170	3,930	244	8,888
Uinta Basin	45	—	13,432	1,097	17,174	3,622	18,040
Total U.S.[1]	852	—	19,647	2,267	21,104	3,866	26,928
Total[1]	45,729	4,934	89,333	18,250	72,323	34,276	176,013

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

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, which is scheduled to be held on May 4, 2018.

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
Scott Saxberg [4] Calgary, Alberta	President, Chief Executive Officer and Director	2003
Kenneth R. Lamont Calgary, Alberta	Chief Financial Officer	Not applicable
C. Neil Smith Calgary, Alberta	Chief Operating Officer	Not applicable
Derek Christie Calgary, Alberta	Senior Vice President, Exploration & Geosciences	Not applicable
Tamara MacDonald Calgary, Alberta	Senior Vice President, Corporate and Business Development	Not applicable
Brad Borggard Calgary, Alberta	Vice President, Corporate Planning and Investor Relations	Not applicable
Mark G. Eade Calgary, Alberta	Vice President, General Counsel and Corporate Secretary	Not applicable
Ryan Gritzfeldt Calgary, Alberta	Vice President, Marketing and Innovation	Not applicable
Steven Toews Calgary, Alberta	Vice President, Engineering and Operations	Not applicable
Peter Bannister [3] [4] Calgary, Alberta	Director and Chairman	2003
Rene Amirault [4] Calgary, Alberta	Director	2014
Laura A. Cillis [1] [2] Calgary, Alberta	Director	2014
D. Hugh Gillard [5] Calgary, Alberta	Director	2003
Ted Goldthorpe [1] [5] [6] New York, New York	Director	2017
Robert F. Heinemann [2] [3] [4] Plano, Texas	Director	2014
Mike Jackson [1] [2] Calgary, Alberta	Director	2016
Barbara Munroe [2] [5] Calgary, Alberta	Director	2016
Gerald A. Romanzin [1] [3] Calgary, Alberta	Director	2004

Notes:
(1) Member of the Audit Committee.
(2) Member of the 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. Goldthorpe was elected to the Board at Crescent Point's 2017 Annual General Meeting.

As at February 14, 2018, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 3,491,838 Common Shares, representing approximately 0.6% of the issued and outstanding Common Shares. Including restricted shares and options, ownership increased to 1.1% on a fully diluted basis.

Scott Saxberg, President, Chief Executive Officer and Director

Scott Saxberg is the President, Chief Executive Officer and a director of Crescent Point. He was a founder of Crescent Point Energy Ltd. in 2001 and has been president of Crescent Point since 2003. Mr. Saxberg has worked in the oil and gas industry since 1992, having held a variety of roles with companies such as Shelter Bay, Wascana Energy Inc., Numac Energy Inc. and Magin Energy Inc.

Mr. Saxberg is a member of the Association of Professional Engineers and Geoscientists of Alberta ("**APEGA**"). Mr. Saxberg has served on the board of directors of Bellamont Exploration Ltd., Catapult Energy 2008 Inc. and Wild Stream Exploration Ltd. Mr. Saxberg holds a Bachelor of Science degree in mechanical engineering from the University of Manitoba.

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 and is a Chartered Professional Accountant, as well as a member of the Chartered Professional Accountants of Alberta and a member of the Institute of Corporate Directors.

C. Neil Smith, Chief Operating Officer

C. Neil Smith is the Chief Operating Officer of Crescent Point, a role he has held with Crescent Point since March 13, 2013. Prior to that, he was Vice President, Engineering and Business Development for Crescent Point. He has been with Crescent Point since 2003 and has worked in the oil and gas industry since 1986, having held a variety of roles with companies including President of Shelter Bay and engineering positions with Amoco Canada Petroleum Ltd. and Coles Gilbert Associates Ltd., the predecessor to Gilbert Laustsen Jung Associates Ltd.

Mr. Smith is a member of the APEGA, the Association of Professional Engineers and Geoscientists of Saskatchewan ("**APEGS**") and Manitoba ("**APEGM**"). He is a previous chair of the Explorers and Producers Association of Canada and a director of the Petroleum Acquisition and Disposition Association. Mr. Smith holds a Bachelor of Science degree in geological engineering from the University of British Columbia and a Master of Business Administration (Dean's List) from the University of Calgary.

Derek Christie, Senior Vice President, Exploration & Geosciences

Derek Christie is a Professional Geologist with over 27 years of experience across North America in both conventional and unconventional reservoir exploration and development. Derek is the Senior Vice President, Exploration & Geosciences of Crescent Point, a role he has held with Crescent Point since February 2017. Prior to that, he was Vice President, Exploration & Geosciences from November 2013 until February 2017 and Vice President, Geosciences for Crescent Point prior thereto. 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 APEGA, APEGS and APEGM.

Tamara MacDonald, Senior Vice President, Corporate and Business Development

Tamara MacDonald is the Senior Vice President, Corporate and Business Development of Crescent Point Energy, a role she has held since January 2016. Prior to that, she was Vice President Land and Corporate Development for Crescent Point from 2004 until 2016. She has worked in the oil and gas industry since 1992, having held a variety of roles with companies such as Shelter Bay, Petrofund Energy Trust, Merit Energy Ltd., Tarragon Oil and Gas Ltd. and Northstar Energy Corp.

Ms. MacDonald is a member of the Canadian Association of Petroleum Landmen, of the American Association of Petroleum Landmen, the Canadian Association of Petroleum and Land Administration, the Petroleum and Acquisition Divestment Association and is a member of the 25th UNICEF Canada Team. She holds a Bachelor of Commerce degree, with a major in Petroleum Land Management, from the University of Calgary.

Brad Borggard, Vice President, Corporate Planning and Investor Relations

Brad Borggard is the Vice President, Corporate Planning and Investor Relations of Crescent Point, a role he has held since February 2017. Mr. Borggard was the Vice President, Corporate Planning of Crescent Point, from January 2010 to February 2017. 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, Vice President, General Counsel and Corporate Secretary

Mark Eade is Crescent Point's Vice President, General Counsel and Corporate Secretary. Mr. Eade has served as corporate secretary since 2004. Prior to being named Vice President at Crescent Point in September 2015, he was a partner with the law firm of Norton Rose Fulbright Canada LLP from August 2011 to August 2015. Prior thereto, Mr. Eade was a partner at McCarthy Tétrault LLP. Mr. Eade has over 20 years of experience in corporate governance, securities and mergers and acquisitions law.

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

Ryan Gritzfeldt, Vice President, Marketing and Innovation

Ryan Gritzfeldt is the Vice President, Marketing and Innovation of Crescent Point Energy, a role he has held since January 2016. Mr. Gritzfeldt previously served as Vice President, Engineering and Business Development East from 2010 until 2015 and as Engineering Manager, Southeast Saskatchewan from 2006 until 2009, both for Crescent Point. 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.

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

Steven Toews, Vice President, Engineering and Operations

Steven Toews is the Vice President, Engineering and Operations of Crescent Point, a role he has held since January 2016. Previously, Mr. Toews served as Vice President, Engineering and Business Development West from 2010 to 2015 and Engineering Manager from 2005 until 2009, both for Crescent Point. Mr. Toews has worked in the oil and gas industry since 1989, including a number of years spent working internationally, with companies such as EnCana Corp., Talisman Energy Inc., International Colin Energy Corp. and Norcen Energy Resources Ltd.

Mr. Toews is a member of APEGA and holds a Bachelor of Science degree in mechanical engineering from the University of Saskatchewan.

Peter Bannister, Director and Chairman

Peter Bannister is Chair of Crescent Point's Board of Directors and is President of Destiny Energy Inc., a private oil and gas company. He has been on the Board of Crescent Point and its predecessor since 2003. 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 is a member of 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 in geology with a minor in economics.

Rene Amirault, Director

Rene Amirault was appointed as the President and Chief Executive Officer of Secure Energy Services Inc. in March 2007 and was elected a director and appointed as Chairman of their 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 received a Certified General Accountant designation in June 1985.

Laura A. Cillis, Director

Laura A. Cillis is an oil and gas executive with more than 25 years of leadership and financial experience in the oilfield services industry. Ms. Cillis is currently a director and member of the Audit Committee of Enbridge Income Fund Holdings Inc. and a director and member of the Audit, Finance and Risk Committee and chair of the Safety & Reliability Committee of Enbridge Pipelines Inc. Ms. Cillis is also a director and member of the Governance and HR Committee of Solium Capital Inc. as well as chair of its Audit Committee. She previously served as 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 also holds a Bachelor of Commerce degree from the University of Alberta.

Ted Goldthorpe, Director

Ted Goldthorpe is a financial professional who has served 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, US 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, is the Chairman of the Young Fellowship of The Duke of Edinburgh's Award and serves on the board of directors for Her Justice and Capitalize for Kids.

D. Hugh Gillard, Director

D. Hugh Gillard is the principal of Saddleback Resources Ltd., a private company involved in equity investments and advisory roles in the energy sector. He has worked in the oil and gas industry since 1972, having led companies such as Kelso Energy Inc., PrimeWest Energy Trust and CanWest Gas Marketing Inc. He has also held a number of senior roles with companies such as Ashland Oil Canada, Dome Petroleum Ltd. and Amoco Canada Resources Ltd. Mr. Gillard has been on the board of Crescent Point and its predecessor since 2003.

Mr. Gillard has served as director of the board of Petrowest Energy Services Trust and of Creststreet Power Income Fund. He is a past member of the Management Advisory Council for the University of Calgary, a past Chairman of the board of Hospice Calgary and a past Chairman of the Calgary Zoological Society. He holds a Bachelor of Commerce degree from the University of Calgary and is a graduate of the Stanford Business School Executive Program.

Robert F. Heinemann, Director

Robert F. Heinemann is an oil and gas executive who brings more than 30 years of experience to the Crescent Point Board. 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.

Mike Jackson, Director

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

Barbara Munroe, Director

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 has been with the Board of Crescent Point since March 2016.

Ms. Munroe is a member of the Association of Corporate Counsel, the Association of Canadian General 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

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. He has been on the Board of Crescent Point and its predecessor since 2004 and has indicated his intention to retire 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 of the Corporation 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. As a result of the suspension and beginning with the August dividend paid on September 15, 2015, shareholders enrolled in the DRIP began receiving the regular monthly cash dividend of $0.10 per share. On March 8, 2016, the regular monthly cash dividend was reduced to $0.03 per share. Previously, on October 15, 2013, the Corporation announced the suspension of the premium component of the DRIP effective with the October 2013 dividend, which was paid on November 15, 2013. 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 of the Corporation, 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 of the Corporation, 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. The Restricted Share Bonus Plan is administered by the board of directors. Under the Restricted Share Bonus Plan at December 31, 2017 the Corporation is authorized to issue up to 12,613,659 Common Shares, of which the Corporation had 3,589,024 restricted shares outstanding at December 31, 2017.

The Restricted Shares vest on terms up to three years from the grant date as determined by the board of directors of the Corporation. 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 the Directors of the Corporation, 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 of the Corporation. 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. 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 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.

The Corporation granted 4,460,046 PSUs in the year ended December 31, 2017.

Stock Option Plan

The Corporation adopted the Stock Option Plan in early 2018, with the purposes of rewarding those persons who promote the growth and success of the Corporation and assisting the Corporation in attracting, motivating and retaining personnel. Although the board of directors of the Corporation has approved the Stock Option Plan, effective as of January 3, 2018, the Stock Option Plan remains subject to approval by the Shareholders at the Corporation's annual meeting on May 4, 2018.

Pursuant to the terms of the Stock Option Plan, a maximum of 10,000,000 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 February 20, 2018, there are 2,988,032 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-employed 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, 2017, the Corporation had a $3.5 billion syndicated unsecured credit facility with a permitted increase (subject to certain conditions) to $4.0 billion (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 totals $3.5 billion through to a maturity date of June 10, 2020. The current maturity date of the Bi-Lateral Credit Facility is June 10, 2020. 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. Concurrent with the drawdown of US$1.73 billion of LIBOR loans, 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 were fixed for purposes of interest and principal repayments at a notional amount of $2.21 billion.

At December 31, 2017, the Corporation had approximately $1.9 billion of senior guaranteed notes outstanding of which $63.8 million become due within one year. The Corporation has closed private offerings of senior guaranteed notes raising total gross proceeds of US$1.39 billion and $197.0 million. 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$1.36 billion senior guaranteed notes, the Corporation has entered into various cross currency swaps to hedge its foreign exchange exposure. Under the terms of the cross currency swaps, the U.S. dollar amounts of the senior guaranteed notes were fixed for purposes of interest and principal repayments at a notional amount of $1.44 billion. 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 license from the NEB and the issue of such a license 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 license. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

Pricing and Marketing – Natural Gas

In Canada, the price of natural gas sold intra-provincially or to the United States is determined by negotiation between buyers and sellers. In the United States, the price of 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 licenses imposed by the DOE. Natural gas may not be imported into Canada or exported from Canada without a license or order from the NEB or imported into the United States or exported from the United States without a license from the DOE. Licenses to export or import natural gas may include various terms and conditions with respect to duration, quantity, tolerance levels, points of exportation or importation,

environmental requirements, among other factors and, in Canada, 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 license 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

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 continues to remain free to restrict exports to the U.S. or Mexico provided that such export restrictions do 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 are prohibited from imposing minimum export or import price requirements except in exceptional circumstances.

NAFTA also requires 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.

The governments of Canada, the U.S. and Mexico are currently engaged in re-negotiating the terms of NAFTA and, at this stage, it is unknown what amendments to NAFTA may result from such re-negotiation and the potential implications on the oil and gas sectors of Canada and the U.S. The Trump administration has even referred to the possibility of terminating NAFTA in its entirety if favorable terms cannot be agreed.

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 Alberta Energy Regulator ("**AER**") on an annual basis.

Producers pay a flat royalty rate of 5 percent 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 new Enhanced Hydrocarbon Recovery Program (the "**EHR Program**") began January 1, 2017 and replaced the existing 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 new 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

Crown Royalties – Oil

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.

Crown Royalties – Gas

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.

Freehold Production Tax

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.

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 and 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 royalty rate for onshore oil and gas is 12.5 percent. Production in Utah and North Dakota may be subject to oil and gas severance taxes. North Dakota severance tax includes exemptions available for low-producing wells, and Utah's includes exemptions for stripper wells, wells within their first six months of production, and wildcat wells within their first twelve months of production. Oil and gas produced from North Dakota state oil and gas leases are subject to royalties ranging from 1/6 to 3/16 of the net mineral interests of all oil and gas produced depending on location. Utah's royalty rate on state-leased oil and gas is 12.5 percent. Royalties payable under private oil and gas leases in both North Dakota and 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, 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 *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* 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 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 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 which 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 storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water 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 annually to report their emissions to Alberta Environment and Parks ("**AEP**"). The CCIR require 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 Alberta-based emission reduction or offset credits; or by contributing to the provincial Climate Change and Emissions Management Fund. Crescent Point does not operate any facilities that are regulated by the Alberta GHG emissions regulations.

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 annually do one or more of the following in recognition that GHG emissions are created when their fuel products are combusted by their customers: (i) acquire and then retire GHC emission performance credits or offset credits, or (ii) make payments to a technology fund at a rate of $30 per tonne for transportation and heating fuels sold and distributed in the province. The distributors typically pass on the compliance costs to their customers, which results in non-agricultural customers paying an additional 6.73 cents per litre for regular gasoline and $1.517 per GJ for natural gas in 2018.

Emissions from landfills will also be subject to a GHG emission levy of $30 a tonne in 2018 and thereafter. Fuel gas consumed in operating oil and gas wells, pipelines and facilities will be subject to the carbon levy commencing January 1, 2023.

The Panel also recommended that the carbon levy increase annually starting January 1, 2019 at a rate equal to the rate of inflation plus 2% per year so long as the levy in Alberta does not significantly exceed carbon prices in comparable jurisdictions or any future national carbon standard.

Methane emission reduction in the oil and gas industry is also a key to Alberta's new GHG emission plan with a goal of reducing oil and gas methane emissions by 45% by 2025. New design specifications will be put in place by the AER over the next several years for oil and gas wells, pipelines and facilities as well as standards for key equipment and operational best practices. Fugitive emission standards will also be included in the regulatory requirements and will require raising current standards for performance, monitoring, measurement and reporting. The AER has been directed to prepare draft directives for public consultation, with final directives to be in place in mid-2018.

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGHGA**") to regulate greenhouse gas emissions in the province. The MRGHGA has not yet come into force.

On December 4, 2017, the Government of Saskatchewan released the province's Climate Change Strategy and announced that it will, in consultation with the oil and gas industry, develop regulations to reduce GHG emissions from oil and gas wells and facilities using a results-based system that will provide each operator the ability to prioritize GHG emission reduction investments and support adoption of innovative emission reduction technology. The Climate Change Strategy also proposes an increase in the use of methane produced in association with oil production for heating and electricity generation by exploring policies aimed at creating market demand for otherwise flared or vented methane emissions. Further, new annual reporting regulations are proposed for all emitters of more than 25,000 tonnes of GHGs annually.

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 December 2002, the Government of Canada ratified the Kyoto Protocol, which requires a reduction in GHG emissions by signatory countries between 2008 and 2012. Canada formally withdrew from the Kyoto Protocol in December 2011.

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. These measures include regulations, codes and standards, targeted investments, incentives, tax measures and programs that directly reduce GHG emissions.

On October 3, 2016, the Government of Canada announced a pan-Canadian approach to the pricing of GHG emissions and, on January 15, 2018, released a draft *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**") for public comment. The federal plan provides 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 standard to be prescribed, failing which the federal

government will begin to levy its own carbon tax on a broad set of emission sources. The initial default carbon tax was set to begin at $10 per tonne of GHG emissions on January 1, 2018 followed by increases of $10 per tonne per year until it reaches $50 per tonne in 2022; however, the GGPPA has not yet come into force and the federal government has announced that the framework will not be imposed on any Canadian province until at least the end of 2018. It is currently unclear whether a tax of $20 per tonne will take effect as of January 1, 2019 in accordance with the current draft of the GGPPA, or whether the draft GGPPA will be amended to re-set its levy schedule to begin at $10 per tonne on January 1, 2019, with $10 per tonne increases each year until January 1, 2023.

The federal government also has a GHG emission reporting requirement under the Canadian Environmental Protection Act, 1999 whereby facilities that emitted 10,000 tonnes or more of GHGs in 2017 must report their emissions to Environment and Climate Change Canada.

Crescent Point anticipates that Government of Canada GHG regulations will apply to its operations in the future and as a result additional costs will be incurred to comply with carbon pricing, GHG emission reduction requirements and to perform necessary monitoring, measurement, verification and reporting of GHG emissions.

Crescent Point's facilities and other operations emit GHG emissions, making it possible that Crescent Point will be subject to federal and provincial GHG emissions controls or reduction requirements if its facilities or operations are above applicable thresholds. In the near term, Crescent Point does not expect to have any facilities in Alberta and Manitoba subject to reporting based on these preliminary regulations.

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 by developing and implementing federal regulations for both existing and new sources of venting and fugitive methane emissions. Previously, on March 10, 2016 Canada and the United States committed to take action on methane emissions through federal regulations as expeditiously as possible.

The Canadian federal government proposed new regulations under the *Canadian Environmental Protection Act, 1999* to reduce the emission of methane from upstream oil and gas activities. The proposed regulations will impose both facility and equipment level requirements. Facilities that produce at least 377,388 bbls (60,000 m^3) of hydrocarbons 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 proposed regulations are expected to cover over 95% of methane emission sources from upstream oil and gas activities.

Methane emission limits are being proposed in five areas.

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, larger oil and gas facilities will have a limit of 3000 m^3 per year on the volume of methane 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, larger oil and gas facilities and ones with larger pumping rates will require controllers to be non or low methane emitting and 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 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 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.

Crescent Point expects that the final regulations will be published in 2018.

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 $48.8 million has been expended to reduce emissions and to meet and exceed provincial and federal targets. In 2017, the Company spent a total of $1.5 million on emissions reduction, primarily on upgrading facilities in Saskatchewan. These upgrades have reduced our emissions, which continue to meet or fall below provincial and federal emission limits.

Crescent Point anticipates changes in environmental legislation may require reductions in emissions from its operations and result in increased capital 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, 2017, Crescent Point owned approximately 32,230 gross (21,012.1 net) wells for which abandonment and/or reclamation costs are expected to be incurred. During the 2017 financial year, Crescent Point spent approximately $25.1 million on well abandonments and environmental remediation activities. Crescent Point estimates that it will spend approximately $33.7 million on well abandonments and environmental remediation and reclamation activities in 2018 and has budgeted accordingly. Crescent Point has estimated the net present value (discounted at approximately 2.25 percent per annum) of its total decommissioning liability (wells and facilities) to be approximately $1.3 billion as at December 31, 2017, based on a future liability (inflated at 2 percent per annum) of approximately $2.0 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 utmost importance to Crescent Point. Crescent Point 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 Corporation safety and environmental rules and procedures;
- Promoting the aspects of careful planning, good judgment, implementation of the Corporation's procedures, and monitoring Corporation activities;

- Communicating openly with members of the public regarding our activities; and
- Amending the Corporation'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. These provisions of the TCJA will be effective for us beginning January 1, 2018.

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 will 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
- other government levies that may be imposed over the producing life of reserves.

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

Dividends on the Corporation's Common Shares are variable.

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

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

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

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

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

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

The properties we acquire may not produce as expected, may be in an unexpected condition and we may be subject to increased costs and liabilities, including environmental liabilities. Although we review properties prior to acquisition in a manner consistent with industry practices, such reviews are not 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, 2017, approximately 9% 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 pay dividends, 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 the dividends that are paid 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 dividends 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 make payment of dividends 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 55% 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 further 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 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;
- 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 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, negatively impacting 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 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 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 has released a draft GGPPA for public comment which, if brought into force as currently drafted, would levy a carbon tax of $10 per tonne of GHG emissions starting January 1, 2018 in each province and territory that does not at that time have a carbon tax or cap and trade system, with the $10 per tonne federal levy increasing $10 per tonne per year until it reaches $50 per tonne on January 1, 2022. The federal government has indicated that the GGPPA will come into force sometime in 2018, but has also announced that the carbon tax framework under the GGPPA will not be imposed on any Canadian province until at least the end of 2018. It is, therefore, currently unclear whether a tax of $20 per tonne will take effect as of January 1, 2019 in accordance with the current draft of the GGPPA, or whether the draft GGPPA will be amended to re-set its levy schedule to being at $10 per tonne on January 1, 2019, with $10 per tonne increases each year until January 1, 2023.

Further, both the Alberta and federal governments have announced that they will each be introducing regulations to reduce methane emissions from the oil and gas sector by up to 45% by 2025. It is likely that any methane reduction regulations which are eventually adopted by the federal and provincial governments will materially impact the nature of oil and gas operations, including those carried out by Crescent Point. At present, it is not possible to predict the impact such federal and provincial methane reduction regulations will have on the business, operations and/or finances of Crescent Point.

In Alberta, the government has advised that it will be implementing a new Carbon Competiveness Incentive Regulation. In Saskatchewan, parts of the Management and Reduction of Greenhouse Gases Act come into force on January 1, 2018. Facilities that emit 50,000 tonnes or more of GHGs will be required to reduce their GHG emissions to a limit that has yet to be determined. At present, it is not possible to predict the specific changes or the impact that the Carbon Competiveness Incentive Regulation or the Management and Reduction of Greenhouse Gases Act or other parts of climate change policies will have on the business, operations and/or finances of Crescent Point. Future legislation in Manitoba and federally, changes to British Columbia's legislation, Alberta's proposed Carbon Competitiveness Incentive Regulation and Saskatchewan's Management and Reduction of Greenhouse Gases Act 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 or the purchase of emission reductions or offset credits. 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. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our assets and operations.

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.

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 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.

Risks Relating to Ownership of our Common Shares

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.

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 and grow its operations. As a growth oriented corporation, 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 future growth 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

The Corporation has established a dividend policy of paying monthly dividends to Shareholders. An objective of the Corporation's dividend policy is to provide Shareholders with relatively stable and predictable monthly 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 each month 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 provide that distributions to Shareholders are not permitted if the Corporation is in default of such Credit Facilities or the payment of such distribution would cause an event of default.

In 2017, 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 2015	–	August 2015	$0.23
September 2015	–	December 2015	$0.10
January 2016	–	March 2016	$0.10
April 2016	–	December 2016	$0.03
January 2017	–	December 2017	$0.03

The Corporation pays cash dividends on the 15th day of each month (or the first business day thereafter) to Shareholders of record on the immediately preceding dividend record date.

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)
2017			
January	18.92	14.98	43,165
February	16.64	13.79	65,631
March	15.32	13.82	65,095
April	15.12	12.72	41,952
May	13.86	11.49	58,054
June	12.33	9.80	61,232
July	10.46	8.97	52,738
August	9.76	8.08	42,404
September	10.44	8.18	56,006
October	10.64	8.90	55,359
November	11.53	8.99	72,081
December	9.80	8.27	59,680
2018			
January	11.59	9.60	91,239
February 1 - 20	10.02	8.40	49,063

NYSE	High (US$)	Low (US$)	Volume (000's)
2017			
January	14.08	11.50	17,622
February	12.66	10.48	28,922
March	11.45	10.24	20,237
April	11.39	9.36	20,076
May	10.16	8.50	24,663
June	9.14	7.51	27,483
July	8.37	6.97	27,731
August	7.80	6.46	21,022
September	8.42	6.74	23,167
October	8.26	6.91	28,987
November	9.06	6.99	34,767
December	7.76	6.42	27,311
2018			
January	9.25	7.70	33,422
February 1 - 20	8.15	6.65	19,306

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 of the Corporation 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: Gerald A. Romanzin (Chair), Laura A. Cillis, 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 or directors of the Corporation 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 and 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
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. He has been on the Board of Crescent Point and its predecessor since 2004 and has indicated his intention to retire 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.
Laura A. Cillis	Ms. Laura A. Cillis is an oil and gas executive with more than 25 years of leadership and financial experience in the oilfield services industry. Ms. Cillis is currently a director and member of the Audit Committee of Enbridge Income Fund Holdings Inc. and a director and member of the Audit, Finance and Risk Committee and chair of the Safety & Reliability Committee of Enbridge Pipelines Inc. Ms. Cillis is also a director and member of the Governance and HR Committee of Solium Capital Inc. as well as chair of its Audit Committee. She previously served as 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 also holds a Bachelor of Commerce degree from the University of Alberta.
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, US 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, is the Chairman of the Young Fellowship of The Duke of Edinburgh's Award and serves on the board of directors for Her Justice and Capitalize for Kids.
Mike Jackson	Mr. Mike Jackson worked in the banking industry from 1984 to 2016 and brings more than 30 years of financial experience in corporate and investment banking. Most recently, he was Managing Director - Investment Banking, Scotiabank Global Banking and Markets, with a focus on the oil and gas industry. Prior to that, Mr. Jackson held several senior management roles at Scotiabank, including Managing Director, Oil & Gas Industry Head & Calgary Office Head from 1999 to 2007 and Vice President & Office Head, Corporate Banking Calgary from 1997 to 1999. Mr. Jackson 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. 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, 2017 and 2016 PricewaterhouseCoopers LLP billed approximately $907,324 and $1,272,988, respectively, as detailed below:

	Year ended December 31	
	2017	**2016**
PricewaterhouseCoopers		
Audit fees [1]	$ 789,500	$ 1,102,751
Audit-related fees [2]	$ 21,974	$ 139,104
Tax fees [3]	$ —	$ 31,133
All other fees	$ 95,850	$ —
Total	$ 907,324	$ 1,272,988

Notes:

(1) Audit fees consist of the aggregate fees billed for the audit or review of the Company's annual and quarterly financial statements that are normally provided in connection with statutory and regulatory filings or engagements.

(2) 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 Company's financial statements and are not reported as Audit fees. The services in this category include costs related to a public financing, French translation and participation fees levied by the Canadian Public Accountability Board.

(3) Tax fees consist of the aggregate fees billed for tax compliance.

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 were paid for professional services rendered by the auditors for French translation of Crescent Point's annual financial statements and Management's Discussion and Analysis filed in 2017. 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 of the Corporation.

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

PricewaterhouseCoopers LLP, the auditors of the Corporation, has audited the consolidated financial statements of the Corporation for the year ended December 31, 2017, as set forth in the Annual Consolidated Financial Statements of the Corporation. PricewaterhouseCoopers LLP has confirmed that it is independent of the Corporation, in accordance with the relevant rules and related interpretation prescribed by the Chartered Professional Accountants of Alberta and the rules of the SEC.

Reserve estimates contained in this AIF are derived from reserve reports prepared by 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, will be contained in our information circular in respect of the annual meeting of Shareholders to be held on May 4, 2018. 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, 2017.

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. **The Board of Directors** ("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 judgements 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.

3. Composition of Committee

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

(b) Qualifications – 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).

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

(e) 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 Corporation 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.

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 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 Corporation 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 judgement, 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 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 judgement 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 Composition, Procedures and Organization

The Committee shall consist of at least two directors as determined by the Board, the majority of whom shall be independent (as required by National Instrument 51-101 Standards and Disclosure for Oil and Gas Activities ("NI 51-101")). Committee members shall also meet the independence requirements of the regulatory bodies to which the Corporation may be subject to. The Board shall appoint the members of the Committee and may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee. If a Committee Chair is not designated by the Board, or is not present at a meeting of the Committee, the members of the Committee may designate a chair by majority vote of the Committee membership. The Secretary of the Corporation, shall act as Secretary of the Committee. The quorum for meetings shall be a majority of the members of the Committee present in person or by telephone or other telecommunications device that permits all persons participating in the meeting to speak and to hear each other. The Committee shall meet at least annually at such times and at such locations as may be requested by the chair of the Committee and at such times as any member of the Committee may request.

3. 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 NI 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:

- review any proposal to change the independent evaluating engineers and/or resolve any differences between the independent evaluating engineers and management;
- 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;
- 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;
- 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;
- review annually the Committee charter and recommend any changes to the Board; and
- to maintain minutes of meetings and periodically report to the Board on significant results of the foregoing activities.

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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time, (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	December 31, 2017	Canada	—	2,796,152	—	2,796,152

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 15, 2018

ORIGINALLY SIGNED BY

Bryan M. Joa, 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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time, (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2017, 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, 2017	U.S.A.	—	2,638,950	—	2,638,950

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 15, 2018

ORIGINALLY SIGNED BY

Bryan M. Joa, 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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook, as amended from time to time, (the "**COGE Handbook**"), maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2017, 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, 2017	Canada				
Total			Nil	10,044,187	Nil	10,044,187

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, 2017)”.

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 30, 2018

ORIGINALLY SIGNED BY

Richard A. Brekke, P.Eng.
Senior Manager, Engineering

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

Vincent K. Hui, P.Eng.
Petroleum Engineer

Shishir Shivhare, 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.

"Scott Saxberg"	*"C. Neil Smith"*
SCOTT SAXBERG President and Chief Executive Officer	C. NEIL SMITH Chief Operating Officer
"Gerald A. Romanzin"	*"Peter Bannister"*
Gerald A. Romanzin Director	Peter Bannister Director

February 28, 2018