UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 40-F

_____ **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

__X__ **Annual Report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended: December 31, 2013
Commission File Number: 001-36258

CRESCENT POINT ENERGY CORP.
(Exact name of Registrant as specified in its charter)

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

Suite 2800, 111 – 5th Avenue S.W.
Calgary, Alberta
T2P 3Y6
(403) 693-0020
(Address and telephone number of registrant's principle executive offices)

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

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

Title of each class:	Name of each exchange on which registered:
Common Shares	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
None

For annual reports, indicate by check mark the information filed with this form:
__X__ Annual Information Form __X__ Audited Annual Financial Statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:
394,993,566 Common Shares (as at December 31, 2013).

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.
Yes ____ No **X**

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).
Yes ____ No ____

PRINCIPAL DOCUMENTS

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

A. Annual Information Form

For the Registrant's Annual Information Form for the year ended December 31, 2013, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2013, including the report of its Independent Auditor with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

For the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2013, see Exhibit 99.3 of this Annual Report on Form 40-F.

CONTROLS AND PROCEDURES

A. Certifications

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

B. Disclosure Controls and Procedures

As of the end of the Registrant’s fiscal year ended December 31, 2013, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Registrant's "disclosure controls and procedures" as defined in Rule 13a-15(e) under Exchange Act. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of the Registrant's disclosure controls and procedures were effective in ensuring that the information required to be disclosed in the reports that the Registrant files with or submits to the Securities and Exchange Commission is recorded, processed, summarized and reported, within the required time periods.

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

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

This annual report does not include a report of management’s assessment regarding internal control over financial reporting due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

D. Attestation of Report of Independent Auditor

This annual report does not include an attestation report of the Company’s registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

E. Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2013, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

AUDIT COMMITTEE FINANCIAL EXPERT

The Company's Board of Directors has determined that Mr. G. Romanzin is an "audit committee financial expert" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee and is "independent" (as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers). For a description of Mr. G. Romanzin's relevant experience in financial matters, see the biographical description for Mr. G. Romanzin under "Directors and Officers" in the Registrant's Annual Information Form for the year ended December 31, 2013, which is filed as Exhibit 99.1 to this Annual Report on Form 40-F.

The SEC has indicated that the designation of Mr. G. Romanzin as an audit committee financial expert does not make him an "expert" for any purpose, impose any duties, obligations or liability on him that are greater than those imposed on members of the audit committee and board of directors who do not carry this designation or affect the duties, obligations or liability of any other member of the audit committee.

CODE OF ETHICS

The Registrant has adopted a "code of ethics" (as that term is defined in paragraph 9(b) of General Instruction B to Form 40-F) ("Code of Ethics"), which is applicable to the directors, officers, employees and consultants of the Registrant and its affiliates (including, its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions). The Code of Ethics is available on the Registrant's website at www.crescentpointenergy.com/accountable/code-of-conduct.

In January 2014, the Registrant amended its Code of Ethics. The amendments clarified the following: honest and accurate preparation of public disclosure materials; prohibiting the concealing of any information from the Registrant's external auditors, internal auditors, Audit Committee or Board; clarifying certain conflicts of interest that arise due to the employee's relationship with the Registrant; requiring written Board approval prior to any officer or employee serving as a director of any corporation that the Registrant does not control; clarifying insider trading policies; prohibiting improper payments to foreign and domestic officials; imposing a duty to comply with applicable Canadian and foreign competition and antitrust legislation; the inclusion of a social media policy; and prohibiting retaliatory action against any employee who reports a violation in good faith and also providing for disciplinary action for any employee who supplies an intentional false report.

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

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The required disclosure is included under the heading "External Auditor Services Fees" in the Registrant's Annual Information Form for the year ended December 31, 2013, filed as Exhibit 99.1 to this Annual Report on Form 40-F, and is incorporated herein by reference.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant does not have any "off-balance sheet arrangements" (as that term is defined in paragraph 11(ii) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors. For a discussion of the Registrant's other off-balance sheet arrangements, see page 12 of the Registrant's Management's Discussion and Analysis for the fiscal year ended December 31, 2013, attached as Exhibit 99.3.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The required disclosure is included under the heading "Contractual Obligations and Commitments" in the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2013, filed as Exhibit 99.3 to this Annual Report on Form 40-F, and is incorporated herein by reference.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Company has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Company's Audit Committee members consist of Mr. G. Romanzin, Mr. D. Gillard, and Mr. P. Bannister.

NYSE STATEMENT OF GOVERNANCE DIFFERENCES

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

FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 40-F are forward-looking statements within the meaning of Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act") and Section 27A of the Securities Act of 1933, as amended. Please see "Special Notes to Reader" in the Annual Information Form of the Company for the year ended December 31, 2013, which is Exhibit 99.1 of this Annual Report on Form 40-F for a discussion of risks, uncertainties, and assumptions that could cause actual results to vary from those forward-looking statements.

UNDERTAKING

Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this report to be signed on its behalf by the undersigned, thereto duly authorized.

Date: March 12, 2014

Crescent Point Energy Corp.

By: /s/ Gregory T. Tisdale
Name: Gregory T. Tisdale
Title: Chief Financial Officer

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Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2013.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2013 together with the Auditors' Report thereon.
99.3	Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2013.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of PricewaterhouseCoopers LLP, Independent Auditor
99.9	Consent of GLJ Petroleum Consultants Ltd., independent engineers
99.10	Consent of Sproule Associates Limited, independent engineers

Exhibit 99.1



CRESCENT POINT ENERGY CORP.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2013

Dated March 11, 2014

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

SPECIAL NOTES TO READER

This annual information form, the documents incorporated by reference herein, and other reports and filings made with the securities regulatory authorities include 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. The use of any of the words "could", "should", "can", "anticipate", "expect", "believe", "will", "may", "projected", "sustain", "continues", "strategy", "potential", "projects", "grow", "take advantage", "estimate", "well-positioned" and similar expressions are intended to identify forward-looking statements. These 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 (as defined herein) 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 annual information form contains forward-looking statements pertaining, among other things, to the following:

- anticipated financial performance;
- 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;
- capital expenditure programs and how it will be funded;
- drilling programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- our future waterflood programs;
- future downspacing;
- expected decommissioning, abandonment, remediation and reclamation costs;
- our tax horizon;
- expected trends in environmental regulation;
- payment of monthly dividends;
- maintenance of a net debt to cash flow ratio of 1.0 times estimated future annual cash flows;
- 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.

By its nature, such forward-looking information is subject to various risks, uncertainties and other factors, including those material risks discussed in the AIF (as defined herein) under "*Risk Factors*" and in the MD&A (as defined herein) under " *Risk Factors*" and "*Forward-Looking Information*", which could cause our actual results and experience to differ materially from the anticipated results or other expectations expressed. The material assumptions in making these forward-looking statements are disclosed in the MD&A under the headings "*Dividends*", "*Capital Expenditures*", "*Decommissioning Liability*", "*Liquidity and Capital Resources*", "*Critical Accounting Estimates*", "*Future Changes in Accounting Policies"* and "*Outlook*".

This disclosure contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control, including, but not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions, blowouts; the risk of carrying out operations with minimal environmental impact; inability to secure adequate production transportation including sufficient crude-by-rail or other alternate transportation; industry conditions including changes in laws and regulations (including the adoption of new environmental laws and regulations) and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on tribal lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and 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; 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; and changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry.

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 and/or resources described can be profitably produced in the future.

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.

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

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.

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.

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. However, we are required to disclose the significant differences between our corporate governance practices and the requirements applicable to U.S. domestic companies listed on the NYSE. 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 annual information form, 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 March 11, 2014 for the year ended December 31, 2013 .

"**Alston**" means Alston Energy Inc.

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

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

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

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

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

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

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

"**Cutpick**" means Cutpick Energy Inc.

"**Cutpick Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving Cutpick and the Corporation, completed on June 20, 2012, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2012* ".

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

"**DSU Plan**" means a deferred share unit plan for eligible participants including non-employee directors .

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

"**Greenhouse Gases**" or "**GHGs**" means any or all of carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulphur hexafluoride (SF_6).

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

"**MD&A**" means the management's discussion and analysis of financial condition and results of operations of the Corporation for the year ended December 31, 2013.

"**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.

"**Painted Pony**" means Painted Pony Petroleum Ltd.

"**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.

"**Reliable**" means Reliable Energy Ltd.

"**Reliable Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving Reliable and the Corporation, completed on May 1, 2012, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2012* ".

"**Restricted Share Bonus Plan**" means an incentive bonus compensation plan for eligible participants including directors, officers, employees and consultants of the Corporation and its affiliates.

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

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

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

"**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.

"**Ute**" means Ute Energy Upstream Holdings LLC, a limited liability company organized under the laws of the State of Delaware and amalgamated with CPEUS on November 29, 2012.

"**Ute Assets**" means the assets of CPEUS owned by Ute prior to its amalgamation with CPEUS.

"Wild Stream" means Wild Stream Exploration Ltd.

"Wild Stream Arrangement" means the plan of arrangement under Section 193 of the ABCA involving Wild Stream and the Corporation, completed on March 15, 2012, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2012* ".

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
bbl/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
MW	mega watt
MW/h	mega watt 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, 2013 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. (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 by way of a court-approved plan of arrangement under the ABCA on July 2, 2009. Pursuant to the Conversion Arrangement, on July 2, 2009, 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 2800, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 3Y6 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. In addition, we continually review and assess numerous corporate and asset acquisition opportunities as part of our ongoing acquisition program.

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 our U.S. operating assets.

CPHI

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

CPLux

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

CPUSH

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

CPEUS

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

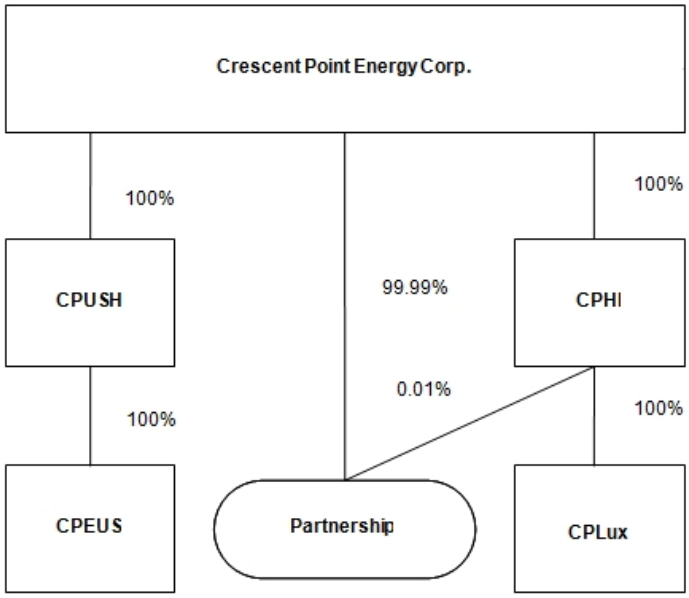
Relationships

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

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

Organizational Structure of the Corporation

The following diagram describes the intercorporate relationships among the Corporation and its material direct and indirect subsidiaries described above as at March 11, 2014. 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.

2011

On January 14, 2011, the Corporation announced the disposal of 5,861,200 Class A Shares of Painted Pony, representing 11.5% of the issued and outstanding Class A Shares of Painted Pony.

On April 14, 2011, the Corporation closed an offering of senior unsecured notes in the United States and Canada on a private placement basis with an aggregate principal amount of US$165 million and $50 million. The terms of the U.S. notes range from 5 to 10 years with a weighted average term of 7.9 years and coupon rates ranging from 3.93% to 5.13% and the Canadian notes have a term of 10 years with a coupon rate of 5.53%.

On June 10, 2011, the Corporation extended the term of the Syndicated Credit Facility by 1 year to June 10, 2014.

On July 14, 2011, the Corporation announced its land position in the Beaverhill Lake light oil resource play at more than 380 (165 net) sections of land. The Corporation also announced that it had ownership and control of 16,750,000 common shares of Arcan Resources Ltd. ("**Arcan**"), a leading Beaverhill Lake producer, representing 19% of the issued and outstanding common shares of Arcan.

On August 31, 2011, the Corporation announced that it had acquired approximately 750 boe/d of production and more than 78 net sections of lower-risk land in North Dakota, U.S., through two strategic acquisitions.

On September 21, 2011 and September 30, 2011, the Corporation announced the closing of its equity offering of 8,625,000 Common Shares and the over-allotment of 400,000 Common Shares at $43.50 per Common Share for aggregate gross proceeds of approximately $392.6 million.

On October 11, 2011, the Corporation announced that it acquired 1,748,000 common shares of Arcan pursuant to Arcan's public offering. The Corporation owns a total of 18,498,000 Arcan common shares, representing approximately 19% of the issued and outstanding common shares of Arcan.

2012

On January 24, 2012, the Corporation announced that it had expanded its land position in the Beaverhill Lake light oil resource play in Alberta by more than 100 net sections through a series of acquisitions and Crown land sales.

On January 25, 2012, the Corporation acquired approximately 940 boe/d of production in southwest Manitoba for cash consideration of $130.3 million.

On March 8, 2012, the Corporation announced the closing of its equity offering of 13,351,500 Common Shares at $45.25 per Common Share for aggregate gross proceeds of approximately $604.2 million.

On March 15, 2012, the Corporation closed the Wild Stream Arrangement for total estimated consideration of $610.2 million, comprised of 12,082,012 Common Shares and assumed debt. See "*Description of Our Business - Reorganizations*".

On March 16, 2012, the Corporation closed its agreement with PetroBakken Energy Ltd. to acquire more than 2,900 boe/d of production and more than 25 net sections of land in the Viewfield Bakken resource play for cash consideration of $426.4 million.

On April 16, 2012, the Corporation closed the sale to a private junior exploration and production company of approximately 900 boe/d of non-core Alberta assets, 80 percent of which was weighted to natural gas, and approximately 20 net sections of undeveloped land for total consideration of $35 million, comprised of $10 million of cash and $25 million of shares in the private company.

On May 1, 2012, the Corporation closed the Reliable Arrangement, pursuant to which the Corporation acquired all of the remaining issued and outstanding shares of Reliable not already owned by the Corporation (as at May 1, 2012, Crescent Point had a 12.8% equity interest in Reliable). Total consideration for the acquisition was $100.7 million, comprised of 1,672,109 Common Shares, assumed debt and the historical cost of Crescent Point's previously held equity investment of $4.8 million. See "*Description of Our Business - Reorganizations*".

On May 22, 2012, the Corporation closed an offering of senior guaranteed notes in the United States and Canada on a private placement basis with aggregate principal amounts of US$268 million and $32 million. The terms of the U.S. notes range from 7 to 10 years with a weighted average term of 9.2 years and coupon rates ranging from 3.39% to 4.00% and the terms of the Canadian notes range from 7 to 10 years with a weighted average term of 9.3 years and coupon rates ranging from 4.29% to 4.76%.

On May 23, 2012, Crescent Point closed a $500 .0 million increase and extension to its syndicated unsecured credit facility with a syndicate of Canadian and international banks, with a maturity date in June 2015. The syndicated unsecured credit facility also includes an accordion feature that allows the Corporation to increase the facility by up to $500 million, for a total of $2.5 billion. The Corporation also renewed and extended its unsecured revolving operating credit facility, with $100 million of credit available and a maturity date in June 2014. In total, the Corporation increased its bank lines from $1.6 billion to $2.1 billion.

On June 1, 2012, Crescent Point acquired approximately 2,500 boe/d of production in the Shaunavon resource play in southwest Saskatchewan for cash consideration of $343.0 million.

On June 20, 2012, the Corporation closed the Cutpick Arrangement for total consideration of approximately $398.3 million, comprised of 7,556,960 Common Shares and assumed debt. See "*Description of Our Business - Reorganizations* ***".***

On July 17, 2012, the Corporation acquired 21,666,667 common share units of Alston at an effective issue price of $0.15 per unit. Each unit was comprised of one common share of Alston and one-half of one common share purchase warrant of Alston. Each warrant entitles the Corporation to acquire one common share of Alston at a price of $0.20 per common share within the 18 month period beginning on July 17, 2012. The units were acquired in connection with a sale by the Corporation to Alston of certain natural gas properties near Alexander, Alberta, which included approximately 225 boe/d of primarily natural gas production.

On August 30, 2012, the Corporation announced the closing of its equity offering of 15,433,000 Common Shares at $41.00 per Common Share for aggregate gross proceeds of approximately $632.8 million.

On November 21, 2012, the Corporation announced the closing of its equity offering of 18,750,000 Common Shares at $40.00 per Common Share and on November 29, 2012 the Corporation announced the partial exercise of the over-allotment option granted to the underwriters to purchase an additional 1,250,000 Common Shares at the offering price of $40.00 per Common Share. Including the partial exercise of the over-allotment option, the Corporation issued 20,000,000 Common Shares for aggregate gross proceeds of $800.0 million.

On November 29, 2012, the Corporation closed the acquisition of Ute for total consideration of approximately $867.6 million, comprised of cash consideration of approximately $783.9 million and assumed debt. See "*Description of Our Business - Ute Acquisition*".

2013

On April 25, 2013, the Corporation announced that its board of directors approved the adoption of an advanced notice by-law, which requires advance notice to the Corporation in circumstances where nominations of persons for election as a director of the Corporation are made by Shareholders other than pursuant to: (i) a requisition of a meeting made pursuant to the provisions of the ABCA; or (ii) a shareholder proposal made pursuant to the provisions of the ABCA.

On June 6, 2013, Paul Colborne resigned from his role as director of the Corporation.

On June 12, 2013, the Corporation closed an offering of senior guaranteed notes in the United States and Canada on a private placement basis with aggregate principal amounts of US$290 million and $10 million. The terms of the U.S. notes range from 5 to 10 years with a weighted average term of 9.7 years and coupon rates ranging from 2.65% to 3.78% and the terms of the Canadian note are 10 years with a coupon rate of 4.11%.

On July 17, 2013 the Corporation renewed and extended the term of the Syndicated Credit Facility by 1 year to June 10, 2016.

On October 15, 2013, the Corporation announced the suspension of the premium component of its DRIP effective with the October 2013 dividend which was paid on November 15, 2013. Effective with the suspension, Shareholders previously enrolled in the premium component of the DRIP received the regular cash dividend amount of $0.23 per share without the 2 percent premium.

2014

On January 22, 2014, the Common Shares began trading on the NYSE under the symbol "CPG".

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. In addition, we continually review and assess numerous corporate and asset acquisition opportunities as part of our ongoing acquisition program. The primary assets of the Corporation are currently the shares in CPHI, units in the Partnership and shares in CPUSH and, indirectly, 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 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, land and possible reserves.

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 continually investigate and search out producing properties including those with large resource potential that we believe will result in meaningful reserve and production additions. We generally focus capital on higher-quality, longer-life reservoirs in proved growth areas that offer existing infrastructure, low cost drilling and multi-zone potential. Our goal is to acquire operational control of properties that we believe offer significant exploitation and development potential.

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 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 quality 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 price 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; and
(i) the effect of energy conservation measures and government regulations.

Fluctuations in commodity prices, quality 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. With recent increases in the volatility of price differentials between WTI and western Canadian crude prices, Crescent Point has expanded its risk management programs to include the hedging of these differentials. The Corporation uses a combination of financial derivatives and fixed-differential physical contracts to hedge these price differentials. For differential hedging, Crescent Point's risk management program allows for hedging a forward profile of 3½ 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 dollars and benchmark natural gas prices are hedged using financial AECO-based instruments transacted in Canadian dollars. Total financial oil and gas hedges in 2013 amounted to approximately 56% of annual production, net of royalties, consisting of approximately 60% of annual crude oil production and approximately 22% of annual natural gas production, net of royalties. The primary objective of this strategy is to enhance the stability of cash dividends. The Corporation recorded a realized derivative loss on oil and gas hedge contracts of $90.9 million in 2013.

The following table summarizes our commitments under all hedging agreements as at December 31, 2013 .

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar

Term	Volume (bbl/d)	Average Swap Price (Cdn$/bbl)	Average Collar Sold Call Price (Cdn$/bbl)	Average Collar Bought Put Price (Cdn$/bbl)	Average Bought Put Price (Cdn$/bbl)	Average Put Premium (Cdn$/bbl)
2014 Weighted Average	57,097	96.71	102.79	88.08	98.12	4.73
2015 Weighted Average	26,750	92.35	97.60	87.41	-	-
2016 Weighted Average	18,000	90.34	-	-	-	-
January to March 2017 Weighted Average	6,000	90.31	-	-	-	-

Financial AECO Natural Gas Derivative Contracts – Canadian Dollar

Term	Contract	Volume (GJ/d)	Average Swap Price (Cdn$/GJ)
2014 Weighted Average	Swap	14,493	3.54
2015 Weighted Average	Swap	13,332	3.55
January to October 2016 Weighted Average	Swap	5,790	3.67

Financial Power Derivative Contracts – Canadian Dollar

Term	Contract	Volume (MW/h)	Fixed Rate ($/MW/h)
2014	Swap	3.0	75.00
2015	Swap	3.0	49.50

Financial Interest Rate Derivative Contracts – Canadian Dollar

Term	Contract	Notional Principal (Cdn$)	Fixed Annual Rate (%)
January 2014 - May 2015	Swap	25,000,000	2.90
January 2014 - May 2015	Swap	25,000,000	3.50
January 2014 - May 2015	Swap	50,000,000	3.09
January 2014 - June 2015	Swap	50,000,000	3.78
January 2014 - July 2015	Swap	50,000,000	3.63

Financial Cross Currency Interest Rate Derivative Contracts

Term	Contract	Receive Notional Principal (US$)	Fixed Annual Rate (US%)	Pay Notional Principal (Cdn$)	Fixed Annual Rate (Cdn%)
January 2014 - March 2015	Swap	37,500,000	4.71	38,287,500	5.24
January 2014 - April 2016	Swap	52,000,000	3.93	50,128,000	4.84
January 2014 - March 2017	Swap	67,500,000	5.48	68,917,500	5.89
January 2014 - April 2018	Swap	31,000,000	4.58	29,884,000	5.32
January 2014 - June 2018	Swap	20,000,000	2.65	20,350,000	3.52
January 2014 - May 2019	Swap	68,000,000	3.39	66,742,000	4.53
January 2014 - March 2020	Swap	155,000,000	6.03	158,255,000	6.45
January 2014 - April 2021	Swap	82,000,000	5.13	79,048,000	5.83
January 2014 - May 2022	Swap	170,000,000	4.00	166,855,000	5.03
January 2014 - June 2023	Swap	270,000,000	3.78	274,725,000	4.32

Financial Cross Currency Principal Derivative Contracts

Settlement Date	Contract	Receive Notional Principal (US$)	Pay Notional Principal (Cdn$)
May 22, 2022	Swap	30,000,000	32,241,000

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. As of January 2014, Crescent Point owned and operated 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 that are not pipeline connected to western Canada or Utah, which significantly diversifies our price and market risk. In addition, we have been able to enter into term sales contracts on a portion of the volumes transported by rail, which set the price differential between benchmark WTI prices and our selling price at the loading terminals. From January to December 2013, approximately 17,400 bbl/d of oil production was contracted with fixed price differentials off WTI. As of early March 2014, approximately 14,200 bbl/d of oil production from January to December 2014 and approximately 2,500 bbl/d of oil production from January 2015 to March 2015 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 Canadian crude oil differentials.

We also mitigate risk by having a well-diversified marketing portfolio for oil and natural gas. As a result of our access to rail transportation, we have significantly increased and diversified the number of counterparties with which we transact. 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 an annual basis. The Policy requires annual credit reviews of all trade counterparties with which the Corporation has, or expects to have, exposures greater than 0.5% of the Corporation’s total aggregate monthly volumetric exposure. 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 more than 50 purchasers and its financial hedging portfolio consists of 12 counterparties. The Corporation's portfolio of counterparty exposures is reviewed monthly by the Chief Financial Officer, the Vice President, Finance and Treasurer, and the Vice President, Marketing and Investor Relations. Counterparty exposures are also reviewed on a quarterly basis by both the Risk Management Committee and the board of directors.

To further mitigate credit risk associated with its physical sales portfolio, Crescent Point has secured credit insurance from a leading global credit insurance provider. This policy provides credit coverage for approximately 30 percent of the Corporation's physical sales portfolio.

The majority of our oil and natural gas volumes are sold in the U.S., Alberta and Saskatchewan. Approximately 79% of our oil volumes are sold in Saskatchewan, 8% in Alberta and 13% in the U.S. Approximately 51% of our natural gas volumes are sold in Saskatchewan, 34% in Alberta and 15% in the U.S.

Revenue Sources

For 2013, our commodity production mix was approximately 91% oil and NGLs and 9% natural gas.

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

For Year Ended	Crude Oil and NGLs	Natural Gas
2013	97%	3%
2012	98%	2%
2011	97%	3%

Competition

We actively compete for reserve acquisitions, exploration leases, licences and concessions and skilled industry personnel with a substantial number of other oil and gas companies, many of which have significantly greater financial resources than we do. Our competitors include major integrated oil and natural gas companies, numerous other independent oil and natural gas entities and individual producers and operators.

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 will be dependent upon developing and maintaining close working relationships with our industry partners and joint operators, our ability to select and evaluate suitable properties and 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 at December 31, 2013, we had 409 full-time employees and 74 consultants at our Calgary and Denver offices. In the field we had 372 full-time field staff and 134 consultants.

Reorganizations

On January 1, 2011, the Corporation amalgamated with Ryland Oil ULC, Darian Resources Ltd. and Shelter Bay ULC.

On March 15, 2012, the Corporation closed the Wild Stream Arrangement for total consideration of $610.2 million, comprised of 12,082,012 Common Shares and assumed debt. The Wild Stream Arrangement further solidified the Corporation’s position as the largest player in the Shaunavon resource play in southwest Saskatchewan, in terms of production and land. Wild Stream’s assets also complemented the Corporation’s existing position in Alberta’s emerging Beaverhill Lake light oil resource play in the Swan Hills area.

On May 1, 2012, the Corporation closed the Reliable Arrangement, pursuant to which the Corporation acquired all of the remaining issued and outstanding shares of Reliable not already owned by the Corporation. Total consideration for the acquisition was $100.7 million, comprised of 1,672,109 Common Shares, assumed debt and the historical cost of Crescent Point's previously held equity investment of $4.8 million. The Reliable Arrangement allowed the Corporation to consolidate the assets that were held through a joint venture with Reliable in the Bakken light oil play in southwest Manitoba.

On June 20, 2012, the Corporation closed the Cutpick Arrangement for total consideration of approximately $398.3 million, comprised of 7,556,960 Common Shares and assumed debt. The assets in the Viking light oil resource play near Provost, Alberta acquired from the Cutpick Arrangement complement and consolidate the Corporation's existing position in the play.

Ute Acquisition

On November 29, 2012, the Corporation closed the acquisition of Ute for total consideration of approximately $867.6 million, comprised of cash consideration of approximately $783.9 million and assumed debt of approximately $83.7 million. The acquisition established a new core area for potential long-term growth in the Uinta Basin light oil resource play in northeast Utah.

Social and Environmental Policies

The Corporation has a voluntary reclamation fund to fund future decommissioning costs and environmental emissions reduction costs. From January 1, 2011 to December 31, 2011, we allocated $0.45 per boe of production. From January 1, 2012 to December 31, 2012, we allocated $0.50 per boe of production. From January 1, 2013 to December 31, 2013, we allocated $0.70 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, 2013 contained in the consolidated report of GLJ dated March 11, 2014 (the "**Crescent Point Reserve Report**"). The Crescent Point Reserve Report evaluated, as at December 31, 2013, 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 GLJ's January 1, 2014 forecast price and cost assumptions. GLJ evaluated approximately 39 percent of the assigned total Proved plus Probable reserves and 30 percent of the total Proved plus Probable value discounted at 10 percent. Sproule evaluated approximately 61 percent of the assigned total Proved plus Probable reserves and 70 percent of the total Proved plus Probable value discounted at 10 percent. Sproule evaluated a majority of our Saskatchewan assets including the Viewfield Bakken properties in southeast Saskatchewan and the Shaunavon properties in southwest Saskatchewan. Sproule evaluated their portion of the reserves using the GLJ forecast price and cost escalation assumptions. GLJ evaluated the Corporation's Alberta and Manitoba assets as well as a portion of the Saskatchewan assets in Canada. GLJ also performed the evaluation of the Corporation's US assets in North Dakota, Montana and Utah. These assets were all evaluated using the GLJ forecast price and cost escalation assumptions. GLJ prepared the total Crescent Point Reserve Report by consolidating the GLJ Canadian and US evaluated properties with the Sproule evaluation using the GLJ 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, and well abandonment costs for only those wells 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 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 Oil		Heavy Oil		Natural Gas Liquids		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 *(MMcf)*	Company Net *(MMcf)*	Company Gross *(Mboe)*	Company Net *(Mboe)*
Proved Developed Producing										
Canada	191,029	168,272	639	626	8,206	7,516	99,292	92,276	216,422	191,794
United States	18,783	15,316	-	-	1,405	1,140	16,811	13,794	22,990	18,755
Total	209,811	183,588	639	626	9,611	8,656	116,104	106,070	239,413	210,549
Proved Developed Non-Producing										
Canada	8,476	7,698	490	462	499	454	9,436	8,704	11,037	10,065
United States	886	731	-	-	58	48	612	522	1,046	866
Total	9,361	8,429	490	462	557	502	10,049	9,226	12,082	10,931
Proved Undeveloped										
Canada	125,171	114,925	146	131	6,817	6,287	63,311	59,013	142,686	131,179
United States	32,339	26,248	-	-	2,050	1,660	25,184	20,537	38,587	31,330
Total	157,511	141,172	146	131	8,867	7,947	88,495	79,550	181,272	162,509
Total Proved										
Canada	324,675	290,895	1,274	1,220	15,522	14,258	172,040	159,992	370,145	333,038
United States	52,008	42,295	-	-	3,513	2,848	42,608	34,853	62,623	50,951
Total	376,683	333,189	1,274	1,220	19,035	17,105	214,647	194,845	432,767	383,989
Total Probable										
Canada	167,553	148,562	672	614	6,903	6,241	89,661	82,359	190,072	169,143
United States	34,343	27,801	-	-	2,318	1,869	25,539	20,730	40,918	33,124
Total	201,896	176,362	672	614	9,222	8,110	115,200	103,089	230,990	202,267
Total Proved Plus Probable										
Canada	492,228	439,456	1,947	1,834	22,425	20,499	261,701	242,352	560,217	502,181
United States	86,351	70,095	-	-	5,832	4,716	68,147	55,582	103,541	84,075
Total	578,580	509,551	1,947	1,834	28,257	25,215	329,848	297,934	663,758	586,256

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% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed Producing										
Canada	10,903,288	8,173,562	6,677,268	5,713,876	5,034,143	9,364,224	7,037,406	5,759,091	4,934,690	4,352,119
United States	870,459	696,588	585,568	509,237	453,692	870,459	696,588	585,568	509,237	453,692
Total	11,773,748	8,870,150	7,262,836	6,223,113	5,487,836	10,234,683	7,733,994	6,344,659	5,443,927	4,805,811
Proved Developed Non-Producing										
Canada	538,553	427,041	356,300	307,391	271,568	398,553	314,665	261,497	224,782	197,926
United States	40,592	31,605	26,117	22,442	19,806	40,592	31,605	26,117	22,442	19,806
Total	579,145	458,646	382,416	329,833	291,374	439,146	346,269	287,614	247,224	217,732
Proved Undeveloped										
Canada	5,391,044	3,690,873	2,662,359	1,993,598	1,534,433	3,956,962	2,623,825	1,819,984	1,300,643	947,235
United States	1,050,415	614,055	375,093	230,789	137,339	903,534	539,414	334,709	207,838	123,758
Total	6,441,459	4,304,928	3,037,452	2,224,387	1,671,773	4,860,496	3,163,240	2,154,694	1,508,481	1,070,994
Total Proved										
Canada	16,832,885	12,291,476	9,695,927	8,014,865	6,840,144	13,719,740	9,975,896	7,840,572	6,460,115	5,497,280
United States	1,961,467	1,342,248	986,777	762,469	610,838	1,814,586	1,267,607	946,394	739,517	597,257
Total	18,794,352	13,633,724	10,682,704	8,777,333	7,450,982	15,534,325	11,243,503	8,786,966	7,199,633	6,094,537
Total Probable										
Canada	10,150,817	6,212,507	4,334,331	3,265,167	2,585,767	7,570,782	4,595,248	3,174,928	2,366,983	1,854,641
United States	1,612,065	892,879	572,962	401,691	297,947	966,214	509,110	309,246	203,050	138,904
Total	11,762,882	7,105,385	4,907,293	3,666,858	2,883,714	8,536,996	5,104,359	3,484,174	2,570,032	1,993,545
Total Proved Plus Probable										
Canada	26,983,702	18,503,983	14,030,257	11,280,032	9,425,911	21,290,522	14,571,144	11,015,500	8,827,098	7,351,920
United States	3,573,532	2,235,126	1,559,740	1,164,160	908,785	2,780,799	1,776,717	1,255,640	942,567	736,161
Total	30,557,234	20,739,109	15,589,997	12,444,192	10,334,697	24,071,321	16,347,861	12,271,140	9,769,665	8,088,082

Note:

(1) Numbers may not add due to rounding.

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

Reserves Category	Revenue (M$)	Royalties (M$)	Operating Costs (M$)	Capital Development Costs (M$)	Abandonment Costs (M$)	Future Net Revenue Before Income Taxes (M$)	Income Tax (M$)	Future Net Revenue After Income Taxes (M$)
Proved								
Canada	33,867,010	4,120,189	9,245,403	3,375,725	292,808	16,832,885	3,113,145	13,719,740
United States	5,425,517	1,366,785	1,247,782	804,460	45,023	1,961,467	146,881	1,814,586
Total	39,292,527	5,486,974	10,493,186	4,180,185	337,831	18,794,352	3,260,026	15,534,325
Proved Plus Probable								
Canada	52,715,700	6,514,293	14,197,810	4,659,872	360,024	26,983,702	5,693,180	21,290,522
United States	9,399,651	2,394,847	2,156,684	1,213,036	61,552	3,573,532	792,732	2,780,799
Total	62,115,352	8,909,140	16,354,494	5,872,908	421,576	30,557,234	6,485,913	24,071,321

Note:

(1) Numbers may not add due to rounding.

Future Net Revenue by Production Group

	Future Net Revenue Before Income Taxes[3] (Discounted at 10% per year) *(M$)*	Percentage *(%)*	Unit Value *($/boe)*	*($/Mcfe)*
Proved				
CANADA				
Light and Medium Oil[1]	9,625,415	99	29.45	4.91
Heavy Oil[1]	34,022	<1	22.22	3.70
Natural Gas[2]	36,489	<1	7.85	1.31
Total Canada	9,695,927	100	29.11	4.85
UNITED STATES				
Light and Medium Oil[1]	986,777	100	19.37	3.23
Heavy Oil[1]	-	-	-	-
Natural Gas[2]	-	-	-	-
Total United States	986,777	100	19.37	3.23
TOTAL				
Light and Medium Oil[1]	10,612,193	99	28.51	4.75
Heavy Oil[1]	34,022	<1	22.22	3.70
Natural Gas[2]	36,489	<1	7.85	1.31
Total Proved	10,682,704	100	27.82	4.64

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.
(4) Numbers may not add due to rounding.

	Future Net Revenue Before Income Taxes[3] (Discounted at 10% per year) *(M$)*	Percentage *(%)*	Unit Value *($/boe)*	*($/Mcfe)*
Proved Plus Probable				
CANADA				
Light and Medium Oil[1]	13,927,073	99	28.24	4.71
Heavy Oil[1]	50,704	<1	22.04	3.67
Natural Gas[2]	52,480	<1	7.82	1.30
Total	14,030,257	100	27.94	4.66
UNITED STATES				
Light and Medium Oil[1]	1,559,740	100	18.55	3.09
Heavy Oil[1]	-	-	-	-
Natural Gas[2]	-	-	-	-
Total	1,559,740	100	18.55	3.09
TOTAL				
Light and Medium Oil[1]	15,486,813	99	27.26	4.54
Heavy Oil[1]	50,704	<1	22.04	3.67
Natural Gas[2]	52,480	<1	7.82	1.30
Total Proved Plus Probable	15,589,997	100	26.59	4.43

Notes:

(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.
(4) Numbers may not add due to rounding.

For future net revenue of the total Proved reserves for the total company, discounted at 10 percent, 99% of the revenue is from light and medium oil, less than 1% from heavy oil, and less than 1% from natural gas. For the total Proved plus Probable reserves for the total company, discounted at 10 percent, 99% of the revenue is from light and medium oil, less than 1% from heavy oil, and less than 1% from natural gas.

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, Probable and possible 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 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 stratigraphic test well.

(g) "**F&D costs**" means finding and development costs.

(h) "**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".

(i) "**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).

(j) "**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.

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

(l) "**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.

(m) "**natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

(n) "**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.

(o) "**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.

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

(q) "**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.

(r) "**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.

(s) "**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.

(t) "**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.

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

(v) "**reservoir**" means a porous and permeable subsurface rock formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

(w) "**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.

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

(y) "**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".

(z) "**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.

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

(bb) "**well abandonment costs**" means costs of abandoning a well (net of salvage value) and of disconnecting the well from the surface gathering system. They do not include costs of abandoning the gathering system or reclaiming the wellsite.

Pricing Assumptions – Forecast Prices and Costs

GLJ and Sproule employed the following pricing, exchange rate and inflation rate assumptions as of December 31, 2013 in estimating our reserves data using forecast prices and costs.

Year	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 *($Cdn/bbl)*	Inflation Rate *(%/yr)*	Exchange Rate *($US/$Cdn)*
Forecast									
2014	4.25	4.03	97.50	92.76	105.20	73.22	57.83	2.0	0.950
2015	4.50	4.26	97.50	97.37	107.11	75.95	58.42	2.0	0.950
2016	4.75	4.50	97.50	100.00	107.00	78.00	60.00	2.0	0.950
2017	5.00	4.74	97.50	100.00	107.00	78.00	60.00	2.0	0.950
2018	5.25	4.97	97.50	100.00	107.00	78.00	60.00	2.0	0.950
2019	5.50	5.21	97.50	100.00	107.00	78.00	60.00	2.0	0.950
2020	5.63	5.33	98.54	100.77	107.82	78.60	60.46	2.0	0.950
2021	5.74	5.44	100.51	102.78	109.97	80.17	61.67	2.0	0.950
2022	5.86	5.55	102.52	104.83	112.17	81.77	62.90	2.0	0.950
2023	5.97	5.66	104.57	106.93	114.41	83.40	64.16	2.0	0.950
2024+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.950

For the year ended December 31, 2013, the average realized sales prices before hedging were $88.48/bbl for light and medium oil, $72.31/bbl for heavy oil, $48.45/bbl for NGLs and $3.61/mcf for natural gas.

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation

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, 2013 against such reserves as at January 1, 2013 based on forecast price and cost assumptions.

CANADA	Light and Medium Oil *(Mbbls)*			Heavy Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2013(1)	304,915	155,913	460,829	2,487	1,088	3,575	14,157	6,790	20,947
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	23,853	18,252	42,106	-	-	-	506	458	963
Technical Revisions	24,847	(7,930)	16,917	(576)	(264)	(840)	2,546	(379)	2,167
Acquisitions	3,714	1,498	5,212	-	-	-	173	78	251
Dispositions	(57)	(110)	(166)	-	-	-	(11)	(47)	(57)
Economic Factors	85	(71)	14	(456)	(152)	(607)	2	3	5
Production	(32,683)	-	(32,683)	(181)	-	(181)	(1,852)	-	(1,852)
December 31, 2013(2)	324,675	167,553	492,228	1,274	672	1,947	15,522	6,903	22,425

CANADA	Associated and Non-Associated Gas (Natural Gas) *(MMcf)*			BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2013(1)	168,674	88,592	257,266	349,672	178,557	528,229
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	9,709	6,273	15,982	25,977	19,757	45,734
Technical Revisions	14,427	(4,225)	10,202	29,222	(9,278)	19,944
Acquisitions	1,083	509	1,592	4,068	1,660	5,728
Dispositions	(280)	(1,245)	(1,525)	(114)	(364)	(478)
Economic Factors	(919)	(243)	(1,163)	(523)	(260)	(783)
Production	(20,652)	-	(20,652)	(38,157)	-	(38,157)
December 31, 2013(2)	172,040	89,661	261,701	370,145	190,072	560,217

UNITED STATES	Light and Medium Oil *(Mbbls)*			Heavy Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2013(1)	43,711	25,687	69,399	-	-	-	1,260	1,059	2,319
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	14,499	11,420	25,918	-	-	-	887	602	1,488
Technical Revisions	(903)	(1,861)	(2,763)	-	-	-	1,581	732	2,312
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	(407)	(903)	(1,310)	-	-	-	11	(74)	(63)
Production	(4,892)	-	(4,892)	-	-	-	(224)	-	(224)
December 31, 2013(2)	52,008	34,343	86,351	-	-	-	3,513	2,318	5,832

UNITED STATES	Associated and Non-Associated Gas (Natural Gas) *(MMcf)*			BOE (Mboe)		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2013(1)	34,380	18,727	53,107	50,701	29,867	80,568
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	9,659	6,773	16,432	16,995	13,150	30,145
Technical Revisions	2,692	933	3,625	1,127	(973)	154
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(338)	(894)	(1,232)	(453)	(1,125)	(1,578)
Production	(3,785)	-	(3,785)	(5,748)	-	(5,748)
December 31, 2013(2)	42,608	25,539	68,147	62,623	40,918	103,541

TOTAL	Light and Medium Oil *(Mbbls)*			Heavy Oil *(Mbbls)*			Natural Gas Liquids *(Mbbls)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2013(1)	348,627	181,600	530,227	2,487	1,088	3,575	15,417	7,849	23,266
Discoveries	-	-	-	-	-	-	-	-	-
Extensions and Improved Recovery	38,352	29,672	68,024	-	-	-	1,394	1,059	2,451
Technical Revisions	23,945	(9,791)	14,154	(576)	(264)	(840)	4,127	352	4,479
Acquisitions	3,714	1,498	5,212	-	-	-	173	78	251
Dispositions	(57)	(110)	(166)	-	-	-	(11)	(47)	(57)
Economic Factors	(322)	(974)	(1,296)	(456)	(152)	(607)	12	(71)	(58)
Production	(37,575)	-	(37,575)	(181)	-	(181)	(2,076)	-	(2,076)
December 31, 2013(2)	376,683	201,896	578,580	1,274	672	1,947	19,035	9,222	28,257

TOTAL	Associated and Non-Associated Gas (Natural Gas) *(MMcf)*			BOE *(Mboe)*		
Factors	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2013(1)	203,053	107,319	310,373	400,373	208,424	608,797
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	19,367	13,047	32,414	42,972	32,907	75,879
Technical Revisions	17,119	(3,292)	13,827	30,348	(10,251)	20,097
Acquisitions	1,083	509	1,592	4,068	1,660	5,728
Dispositions	(280)	(1,245)	(1,525)	(114)	(364)	(478)
Economic Factors	(1,257)	(1,137)	(2,395)	(976)	(1,385)	(2,361)
Production	(24,437)	-	(24,437)	(43,905)	-	(43,905)
December 31, 2013(2)	214,647	115,200	329,848	432,767	230,990	663,758

Notes:

(1) The Corporation has no unconventional reserves (Bitumen, Synthetic Crude Oil, Natural Gas from Coal, Natural Gas from Hydrates, Shale Oil, Shale Gas, etc.).

(2) Numbers may not add due to rounding.

Undeveloped Reserves

The following discussion generally describes the basis on which we attribute Proved and Probable undeveloped reserves. Our 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. In addition, such reserves may relate to planned infill drilling locations. The majority of these reserves are planned to be on stream within a three year timeframe. 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 Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		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
2010	18,581	96,980	-	125	19,269	44,347	1,317	4,885	23,110	109,381
2011	27,772	108,221	145	226	15,260	51,273	1,201	5,407	31,662	122,399
2012	49,472	152,248	183	347	33,277	87,807	1,636	7,640	56,836	174,869
2013	37,482	157,511	39	146	25,491	88,495	1,481	8,867	43,250	181,272

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, infill drilling locations and lands contiguous to production. The majority of these reserves are planned to be on stream within a five year timeframe. The following table provides the timing of the initial reserve assignments for the Corporation's Probable undeveloped gross reserves.

Timing of Initial Probable Undeveloped Reserves Assignment

	Light & Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		Natural Gas Liquids (Mbbl)		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
2010	18,115	69,189	39	212	12,675	26,143	734	2,511	21,000	76,270
2011	22,493	73,204	137	295	11,870	32,184	673	2,726	25,281	81,589
2012	42,350	109,275	63	322	26,525	60,957	1,341	4,432	48,175	124,188
2013	42,447	118,895	8	214	23,412	64,916	1,482	4,985	47,839	134,913

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 (M$)

	Canada		US		Total	
Year	**Total Proved**	**Total Proved Plus Probable**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved**	**Total Proved Plus Probable**
2014	847,259	1,132,660	239,975	286,925	1,087,234	1,419,585
2015	781,503	1,127,649	248,411	409,570	1,029,914	1,537,219
2016	733,100	938,428	247,449	407,909	980,549	1,346,337
2017	591,073	835,750	64,025	87,204	655,098	922,953
2018	347,120	543,984	4,600	21,429	351,720	565,413
2019	9,674	9,468	-	-	9,674	9,468
2020	6,449	7,334	-	-	6,449	7,334
2021	4,022	3,706	-	-	4,022	3,706
2022	3,354	4,469	-	-	3,354	4,469
2023	5,276	4,887	-	-	5,276	4,887
2024	3,879	3,606	-	-	3,879	3,606
2025	2,427	2,723	-	-	2,427	2,723
Subtotal[(1)]	3,335,135	4,614,665	804,460	1,213,036	4,139,595	5,827,701
Remainder	40,589	45,207	-	-	40,589	45,207
Total[(1)]	3,375,725	4,659,872	804,460	1,213,036	4,180,185	5,872,908
10% Discounted	2,735,739	3,774,524	687,972	1,026,431	3,423,711	4,800,955

Note:

(1) Numbers may not add due to rounding.

Company Annual Abandonment Costs (M$)

	Canada		US		Total	
Year	**Total Proved**	**Total Proved Plus Probable**	**Total Proved**	**Total Proved Plus Probable**	**Total Proved**	**Total Proved Plus Probable**
2014	4,272	3,971	1,373	1,220	5,646	5,191
2015	1,840	1,121	291	108	2,130	1,229
2016	2,951	1,999	644	384	3,596	2,383
2017	5,483	4,109	146	108	5,629	4,217
2018	4,025	3,186	651	312	4,677	3,498
2019	5,745	3,182	435	345	6,180	3,527
2020	5,023	3,506	513	516	5,536	4,022
2021	5,610	3,394	407	383	6,017	3,776
2022	6,633	3,316	465	442	7,098	3,758
2023	5,742	3,565	437	486	6,179	4,051
2024	9,030	5,215	642	304	9,672	5,519
2025	7,459	4,662	851	177	8,310	4,839
Subtotal[(1)]	63,813	41,227	6,856	4,785	70,669	46,012
Remainder	228,995	318,797	38,167	56,767	267,162	375,564
Total[(1)]	292,808	360,024	45,023	61,552	337,831	421,576
10% Discounted	65,870	54,110	8,559	6,727	74,429	60,837

Note:

(1) Numbers may not add due to rounding.

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 (including proceeds from our DRIP), 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. The current rate available to us under prime loan drawdowns, is 3.50% per annum. We expect to fund our total 2014 capital program with internally generated cash flow and, although quarterly fluctuations in funding levels are expected, our objective is to maintain our current leverage throughout 2014. Our objective is to maintain our net debt to cash flow ratio at 1.0 times estimated future annual cash flows.

Major Oil and Gas Properties

The following is a description of the Corporation's major oil and natural gas properties, plants, facilities and installations in which we have an interest and that are material to our operations and activities. 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, 2013.

Crescent Point has continued to focus on the development of large resource play assets in Canada and the United States. The properties discussed below account for a majority of the reserve bookings prepared by GLJ and Sproule for year-end 2013, and are representative of the high quality assets in the Corporation's portfolio.

CANADA

Viewfield Bakken Resource Play

The Viewfield Bakken light oil resource play area in southeast Saskatchewan continues to experience production and reserve growth as a result of improved drilling and completion techniques, step-out and infill drilling, as well as waterflood performance.

Crescent Point spent $563.5 million, or 33 percent, of its 2013 capital development program on its Viewfield Bakken light oil resource property. The continued success of Crescent Point's development program in the Bakken play has resulted in the expansion of the Viewfield gas facility from 30 MMcf/d to 42 MMcf/d, which is expected to be completed in early 2014, and will have the potential to be expanded an additional 12 MMcf/d when required in the future. In Viewfield, the Corporation now has the ability to ship more than 45,000 bbl/d by rail representing more than 35 percent of the Corporation's yearly average production guidance for 2014.

In 2013, the Corporation's independent engineering evaluator completed a classic reservoir study on select existing waterflood patterns with sufficient history for analysis, and has found ultimate long-term recovery factors up to 30 percent maybe achievable in those areas. At December 31, 2013, the Corporation had converted a total of 66 producing wells to water injection wells in 29 waterflood sections in the Viewfield Bakken oil resource play. As more injection patterns are established, the waterflood is expected to add proven reserves, with the potential to also reduce our future overall corporate decline rate.

Early in the third quarter of 2013, the Government of Saskatchewan provided technical approval for the first of four proposed units in the play. The Corporation is now in the process of finalizing the first Bakken unit and progress continues towards future unitization of the remaining three proposed units.

In 2013, total Proved plus Probable reserves in the Viewfield Bakken resource play, excluding Flat Lake, grew from 206.5 MMboe to 221.4 MMboe, representing a 7 percent increase over year-end 2012. Technical and development Proved plus Probable reserve additions totalled 29.5 MMboe in 2013. Since acquiring the properties in early 2007, the Corporation has added approximately 205.8 MMboe of positive Proved plus Probable technical and development reserves in the Viewfield Bakken and Flat Lake resource plays through continual improvement of drilling and completion techniques, as well as successful step-out and infill drilling. Additionally in the Viewfield Bakken, waterflood patterns were assigned an incremental 3% recovery factor from the previous primary recoverable reserve levels. This is a small portion of the future upside potential reflected in the independent waterflood evaluation noted above. The Corporation has 970 net locations booked to total Proved plus Probable reserves as of year-end 2013.

Crescent Point expects to continue to spend significant capital in 2014 in the Viewfield Bakken resource play, as a part of its ongoing strategic development of the play. The Corporation's total capital budget for the area is approximately $580 million for 2014, including drilling approximately 230 gross (215 net) wells and investing approximately $80 million for land, seismic and facilities. As in prior years, this program is designed to expand and diversify our facilities, expand waterflood development and develop our large drilling inventory.

Shaunavon Resource Play

In 2013, the Corporation continued to develop the medium gravity Upper and Lower Shaunavon oil resource plays through development and infill drilling, using improved technologies and waterflood activities to enhance recoveries. The Corporation is maintaining its focus on unitization activities in the area as a follow-up to the recently approved Leitchville North Shaunavon Voluntary Unit No. 1 and associated 2013 waterflood approval.

Crescent Point spent $347.3 million of its 2013 capital budget in the Shaunavon area. The Corporation has experienced significant success in the past year as a result of converting to cemented liner completions from the prior packer completion techniques for horizontal wells. In 2013, Crescent Point continued to infill drill the Upper and Lower Shaunavon to eight wells per section, which continue to produce at rates similar to rates observed at the original offsets when they were originally placed on production. The 2012 constructed Dollard rail-loading facility has been expanded from an initial 4,000 bbl/d capacity to 12,000 bbl/d. In addition, two large oil storage tanks are expected to be commissioned in the first quarter of 2014 for total storage of up to 120,000 bbl of marketable crude.

In 2013, Crescent Point continued to focus on waterflood implementation by increasing the number of water injection wells in the play. By year-end 2013, the Corporation expanded its water injection well count in the Upper and Lower Shaunavon resource plays through both acquisitions and additional conversions to 42 active injection wells, including 20 horizontal injection wells. The Government of Saskatchewan approved the application for creation of the Leitchville North Shaunavon Voluntary Unit No. 1, representing a significant milestone in the Lower Shaunavon resource play development. The Government subsequently approved a proposal for waterflood implementation in the unit. Crescent Point plans to apply for unitization for the second development area, adjacent to the first unit, in the second quarter of 2014.

As of year-end 2013, Crescent Point had booked total Proved plus Probable reserves of 153.4 MMboe in the Shaunavon area, an increase of 5 percent from 145.9 MMboe in 2012, including approximately 13.2 MMboe due to positive technical and development reserve additions in 2013. Since the original Shaunavon acquisition in 2009, the Corporation has added approximately 61 MMboe of positive total Proved plus Probable technical and development reserves. The Corporation has 783 net locations booked to Shaunavon total Proved plus Probable reserves as of year-end 2013.

In 2014, Crescent Point expects to spend $422 million of its capital budget in the Shaunavon area. The Corporation expects to drill approximately 145 gross (142 net) wells primarily using the improved cemented liner completion technique, as well as invest more than $80 million on land, seismic and facilities. The facility capital includes the continued development and expansion of crude oil gathering systems and the upgrading of key crude oil batteries. These facility expenditures are expected to accommodate both current and future growth in production volumes. The Corporation plans to continue to expand the waterflood projects within the Lower and Upper Shaunavon zones during the year.

Battrum and Cantuar Regional Area

The Battrum and Cantuar regions represent the continued success and growth of Crescent Point's mature assets producing out of the Roseray and Success Sands. The Corporation has recorded cumulative positive reserve revisions in both of these legacy areas since the original property acquisition in early 2006.

In 2013, Crescent Point spent $18.1 million of its capital budget in the Battrum and Cantuar regions, primarily in existing units on drilling, facilities projects and production optimization projects.

Since acquiring the Battrum property in 2006, the Corporation has increased total Proved plus Probable reserves in the three area units from 5.6 MMboe to a total of 17.6 MMboe at year-end 2013. During this same period, Crescent Point has had similar success in Cantuar increasing total Proved plus Probable reserves in the Cantuar unit from 9.7 MMboe to a total of 14.6 MMboe at year-end 2013.

The Corporation plans to continue to focus on production optimization projects and infill drilling in 2014, with plans to drill up to 12 gross (5 net) oil wells in Battrum and 15 gross (8 net) oil wells in Cantuar.

UNITED STATES

Utah Uinta Basin Resource Play

In late 2012, through the acquisition of Ute, the Corporation became active in the Uinta Basin in northeast Utah, a multi-zone, large oil-in-place light oil resource play. The Corporation considers the Uinta Basin a largely untapped resource, with significant growth opportunities through improved step-out and development drilling, new completion techniques, enhanced recovery techniques as well as advancing marketing opportunities.

The central Uinta Basin is the intersection between two main oil-bearing plays within the basin: Monument Butte and Altamont-Bluebell, which have been producing for more than 50 years. Exploration and development agreements ("**EDAs**"), entered into under the authority of the Indian Mineral Development Act of 1982 and approved by the Bureau of Indian Affairs within the Department of the Interior, with the Ute Indian Tribe of the Uintah and Ouray Reservation (the "**Tribe**") govern more than 150 net sections of land in the central basin, of which the majority is undeveloped. The EDAs cover several core project areas including the Randlett, Horseshoe Bend, Rocky Point, Blacktail Ridge, North Monument Butte, Bridgeland and Lake Canyon properties. The EDAs create an operating interest in the Tribe's minerals, requires payment of royalties and rentals to the Tribe and reserve the Tribe's right to take royalty production in kind. The EDAs granted Crescent Point an interest in real property, which represents a recordable interest in real estate under Utah law. The lands governed by these EDAs were released for development less than 10 years ago. The EDAs have an initial five-year term, with the majority of the EDAs being issued in the last five years, and all of the EDAs contain extension provisions related to meeting certain drilling commitments which provisions, if met, allow for two additional five-year terms that have the potential to provide the Corporation with up to an initial 15-year term to develop the assets.

In 2013, Crescent Point spent $235.3 million of its capital budget in the area, including the first application of horizontal drilling for the Corporation in the area. Development activities also included the installation of gas gathering facilities and the completion of a rail facility in December, which opened up additional markets for light crude oil produced in the Uinta Basin.

The Corporation is utilizing successful completion techniques from both the US and Canada to improve well performance in the Uinta Basin. Future plans include additional horizontal well tests and pilot testing the reservoir potential for application of waterflood technology in the stacked pay zone.

Since the acquisition, the total Proved plus Probable reserves in the Uinta Basin have grown 27 percent from 55.1 MMboe to 70.0 MMboe in thirteen months of ownership. Technical and development Proved plus Probable reserve additions totalled 16.5 MMboe in 2013. The Corporation increased the number of total Proved plus Probable net reserve locations at December 31, 2013 to 333 from 274 at December 31, 2012.

In 2014, Crescent Point plans to spend approximately $172 million in the area, with $127 million allocated to drilling and completion operations throughout the basin. A total of 106 gross (53 net) wells are expected to be drilled in 2014.

North Dakota

The Bakken light oil resource play in North Dakota is one of the fastest growth areas for production anywhere in North America. In 2013, Crescent Point spent $138.5 million of its capital budget in the area, including drilling in the Bakken and Three Forks zones.

In 2013, the Corporation focused on the implementation of drilling and completion techniques developed in the Corporation's Viewfield Bakken resource play to the Corporation's North Dakota assets, as well as reducing costs in the area.

At year-end 2013 total Proved plus Probable reserves increased to 33.4 MMboe from 23.5 MMboe at year-end 2012, representing a 42 percent increase over year-end 2012. Technical and development Proved plus Probable reserve additions totalled 12.2 MMboe in 2013. The Corporation increased the number of total Proved plus Probable net reserve locations at December 31, 2013 to 56 from 43 at December 31, 2012.

In 2014, Crescent Point plans to spend approximately $24 million, including approximately $8 million for land to hold and expand its current operated position in Williams County. The Corporation expects to drill 12 gross (2 net) wells in North Dakota in 2014.

Oil and Gas Wells

Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Southeast Saskatchewan and Manitoba	4,456	2,581	-	-
Southwest Saskatchewan	1,407	1,060	488	240
Alberta and West Central Saskatchewan	882	632	350	241
TOTAL CANADA	6,745	4,273	838	481
U.S.				
North Dakota and Montana	194	50	5	4
Utah	711	331	7	2
TOTAL U.S.	905	381	12	6
Total	7,650	4,654	850	487

Non-Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
CANADA				
Southeast Saskatchewan and Manitoba	83	65	-	-
Southwest Saskatchewan	48	44	1	1
Alberta and West Central Saskatchewan	20	17	1	1
TOTAL CANADA	151	126	2	2
U.S.				
North Dakota and Montana	2	-	-	-
Utah	2	1	-	-
TOTAL U.S.	4	1	-	-
Total	155	127	2	2

All of the Corporation's oil and gas wells are onshore.

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, 2013

	Gross Acres	Net Acres	Net Acres Expiring Within One Year
CANADA			
Alberta	642,655	461,960	116,275
Saskatchewan	1,313,099	1,193,402	236,870
Manitoba	179,425	175,809	30,529
Total	2,135,179	1,831,171	383,674
U.S.			
Montana	231,067	177,615	10,944
North Dakota	82,801	63,542	12,409
Utah	306,904	121,775	12,524
Total	620,772	362,932	35,877
Total	2,755,951	2,194,103	419,551

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, 2013, in each of Canada and the United States.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
CANADA						
Oil wells	467	391.4	82	70.2	549	461.6
Natural Gas wells	-	-	-	-	-	-
Service wells	4	3.1	-	-	4	3.1
Stratigraphic test	1	1.0	-	-	1	1.0
Dry Holes	1	1.0	-	-	1	1.0
Total	473	396.5	82	70.2	555	466.7

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
U.S.						
Oil wells	141	54.5	41	28.3	182	82.8
Natural Gas wells	-	-	-	-	-	-
Service wells	-	-	-	-	-	-
Stratigraphic test	-	-	-	-	-	-
Dry Holes	-	-	-	-	-	-
Total	141	54.5	41	28.3	182	82.8

For details on the most important current and likely exploration and development activities during 2013, see " *Statement Of Reserves Data And Othe Oil And Gas Information – Major Oil and Gas Properties*".

The Corporation's work commitments for its proved properties (including drilling commitments) and timing are as follows:

($000's)	Total	2014	2015	2016
Canada	-	-	-	-
U.S.	-	-	-	-
TOTAL	-	-	-	-

Additional Information Concerning Abandonment and Reclamation Costs

We estimate well abandonment costs area by area. Such costs are assigned to the reserve wells in the Crescent Point Reserve Report and are included as deductions in arriving at future net revenue. The expected total abandonment costs included in the Corporation's Engineering Report for an estimated 7,377 net wells under the Proved reserves category is $337.8 million undiscounted ($74.4 million discounted at 10%), of which a total of $11.4 million is estimated to be incurred in 2014, 2015 and 2016.

Tax Horizon

Crescent Point has tax pools of approximately $8.4 billion at December 31, 2013 to shelter future taxable income. Including the impact of income from the Partnership for the year ended December 31, 2013, the net tax pools remaining are approximately $7.9 billion. Based on this pool balance and the forecast of cash flows using approximately US$100.00 WTI in 2014, approximately US$102.00 in 2015, a 0.90 US$/Cdn$ exchange rate and 2% inflation, with a 2014 development capital budget of $1.75 billion, Crescent Point does not expect to be taxable until 2015.

Costs Incurred(1)

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2013. The total capital costs were approximately $1.8 billion in 2013.

($000's)	Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	117,319	6,271	180,041	1,160,324
U.S.	(3,659)	(1,664)	73,561	310,581
Total	113,660	4,607	253,602	1,470,905

Note:
(1) Costs incurred exclude capitalized administration.

Production Estimates

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2014 in the estimates of future net revenue with forecast pricing from Proved reserves disclosed above under the heading "*Reserves Data - Forecast Prices and Costs*".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Natural Gas	NGLs	Total
	(bbl/d)	*(bbl/d)*	*(Mcf/d)*	*(bbl/d)*	*(boe/d)*
CANADA					
Southeast Saskatchewan and Manitoba	67,272	-	30,759	5,192	77,590
Southwest Saskatchewan	27,422	-	7,147	134	28,746
Alberta and West Central Saskatchewan	8,018	341	23,610	411	12,705
Total CANADA(1)	102,710	341	61,515	5,738	119,041
U.S.					
North Dakota and Montana	3,651	-	2,150	390	4,400
Utah	8,904	-	8,218	369	10,643
Total U.S.(1)	12,555	-	10,368	760	15,043
Total(1)	115,266	341	71,883	6,498	134,085

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

Production in southeast Saskatchewan/Manitoba and southwest Saskatchewan accounts for 58% and 21%, respectively, of the Corporation's Proved production estimate in 2014.

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2014 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	Natural Gas	NGLs	Total
	(bbl/d)	*(bbl/d)*	*(Mcf/d)*	*(bbl/d)*	*(boe/d)*
CANADA					
Southeast Saskatchewan and Manitoba	77,659	-	35,485	6,003	89,576
Southwest Saskatchewan	32,251	-	8,626	160	33,849
Alberta and West Central Saskatchewan	9,332	358	25,520	460	14,402
Total CANADA(1)	119,241	358	69,632	6,623	137,826
U.S.					
North Dakota and Montana	4,318	-	2,543	467	5,209
Utah	10,489	-	9,119	412	12,421
Total U.S.(1)	14,807	-	11,661	880	17,630
Total(1)	134,048	358	81,293	7,502	155,456

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

Production in southeast Saskatchewan/Manitoba and southwest Saskatchewan accounts for 58% and 22%, respectively, of the Corporation's total Proved plus Probable production estimate in 2014.

Production History

The following table discloses, on a quarterly and annual basis for the year ended December 31, 2013, 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, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013	2013
CANADA					
Light and Medium Crude Oil *(bbl/d)*	89,291	87,238	85,389	96,218	89,542
Heavy Crude Oil *(bbl/d)*	575	490	453	464	495
NGLs *(bbl/d)*	4,777	5,261	5,237	5,014	5,073
Natural gas *(Mcf/d)*	59,135	57,728	53,659	55,874	56,582
Total *(boe/d)*	104,499	102,610	100,022	111,008	104,540
U.S.					
Light and Medium Crude Oil *(bbl/d)*	11,672	13,082	15,508	13,314	13,404
Heavy Crude Oil *(bbl/d)*	-	-	-	-	-
NGLs *(bbl/d)*	204	538	745	961	615
Natural gas *(Mcf/d)*	7,730	9,414	10,126	14,143	10,370
Total *(boe/d)*	13,164	15,189	17,941	16,632	15,747
TOTAL					
Light and Medium Crude Oil *(bbl/d)*	100,962	100,320	100,896	109,532	102,946
Heavy Crude Oil *(bbl/d)*	575	490	453	464	495
NGLs *(bbl/d)*	4,982	5,799	5,983	5,975	5,688
Natural gas *(Mcf/d)*	66,865	67,142	63,785	70,017	66,952
Total *(boe/d)*	117,663	117,799	117,963	127,641	120,288

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, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013	2013
CANADA					
Prices Received – net of hedging	81.15	86.44	95.08	81.51	85.88
Royalties	(15.09)	(13.76)	(19.59)	(14.82)	(15.78)
Production Costs	(13.08)	(13.04)	(12.45)	(10.65)	(12.26)
Transportation Costs	(2.18)	(2.44)	(2.58)	(2.29)	(2.37)
Netback	50.80	57.20	60.46	53.75	55.47
U.S.					
Prices Received – net of hedging	84.36	84.16	92.15	84.72	86.67
Royalties	(22.40)	(22.42)	(22.24)	(21.04)	(22.02)
Production Costs	(12.91)	(14.33)	(13.00)	(16.50)	(14.18)
Transportation Costs	(1.71)	(1.32)	(0.59)	(0.72)	(1.04)
Netback	47.34	46.09	56.32	46.46	49.43
TOTAL					
Prices Received – net of hedging	81.52	86.14	94.63	81.90	85.98
Royalties	(15.93)	(14.89)	(20.00)	(15.58)	(16.59)
Production Costs	(13.06)	(13.21)	(12.54)	(11.36)	(12.51)
Transportation Costs	(2.12)	(2.30)	(2.27)	(2.10)	(2.20)
Netback	50.41	55.74	59.82	52.86	54.68

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013	2013
CANADA					
Prices Received – net of hedging	58.93	72.09	79.66	71.83	70.02
Royalties	(8.21)	(16.86)	(14.49)	(14.43)	(13.26)
Production Costs	(9.50)	(10.87)	(10.43)	(9.39)	(10.03)
Transportation Costs	(1.58)	(2.04)	(2.16)	(2.02)	(1.93)
Netback	39.64	42.32	52.58	45.99	44.80
U.S.					
Prices Received – net of hedging	-	-	-	-	-
Royalties	-	-	-	-	-
Production Costs	-	-	-	-	-
Transportation Costs	-	-	-	-	-
Netback	-	-	-	-	-
TOTAL					
Prices Received – net of hedging	58.93	72.09	79.66	71.83	70.02
Royalties	(8.21)	(16.86)	(14.49)	(14.43)	(13.26)
Production Costs	(9.50)	(10.87)	(10.43)	(9.39)	(10.03)
Transportation Costs	(1.58)	(2.04)	(2.16)	(2.02)	(1.93)
Netback	39.64	42.32	52.58	45.99	44.80

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

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013	2013
CANADA					
Prices Received	46.91	43.18	51.47	53.89	48.87
Royalties	(3.57)	(3.34)	(4.74)	(4.23)	(3.98)
Production Costs	(7.56)	(6.51)	(6.74)	(7.04)	(6.95)
Transportation Costs	(1.26)	(1.22)	(1.40)	(1.51)	(1.35)
Netback	34.52	32.11	38.59	41.11	36.59
U.S.					
Prices Received	51.74	48.04	46.63	40.57	44.96
Royalties	(10.43)	(12.50)	(10.61)	(8.02)	(9.99)
Production Costs	(7.92)	(8.18)	(6.58)	(7.90)	(7.56)
Transportation Costs	(1.05)	(0.75)	(0.30)	(0.34)	(0.48)
Netback	32.34	26.61	29.14	24.31	26.93
TOTAL					
Prices Received	47.10	43.64	50.87	51.74	48.45
Royalties	(3.85)	(4.19)	(5.47)	(4.84)	(4.63)
Production Costs	(7.58)	(6.67)	(6.72)	(7.18)	(7.01)
Transportation Costs	(1.25)	(1.18)	(1.26)	(1.33)	(1.25)
Netback	34.42	31.60	37.42	38.39	35.56

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

	Three Months Ended				Year Ended
($ per Mcf)	March 31, 2013	June 30, 2013	Sept. 30, 2013	Dec. 31, 2013	2013
CANADA					
Prices Received - net of hedging	3.73	3.91	3.15	4.10	3.73
Royalties	(0.28)	(0.18)	(0.21)	(0.42)	(0.27)
Production Costs	(0.93)	(0.87)	(0.71)	(0.82)	(0.83)
Transportation Costs	(0.25)	(0.33)	(0.23)	(0.27)	(0.27)
Netback	2.27	2.53	2.00	2.59	2.36
U.S.					
Prices Received - net of hedging	3.61	4.23	3.76	3.80	3.85
Royalties	(0.82)	(1.24)	(0.59)	(0.83)	(0.86)
Production Costs	(0.47)	0.16	0.83	(1.48)	(0.36)
Transportation Costs	(0.31)	(1.08)	(1.39)	(1.45)	(1.14)
Netback	2.01	2.07	2.61	0.04	1.49
TOTAL					
Prices Received - net of hedging	3.72	3.95	3.24	4.04	3.74
Royalties	(0.34)	(0.33)	(0.27)	(0.50)	(0.36)
Production Costs	(0.88)	(0.73)	(0.46)	(0.95)	(0.76)
Transportation Costs	(0.25)	(0.43)	(0.42)	(0.51)	(0.41)
Netback	2.25	2.46	2.09	2.08	2.21

Production Volume by Field

The following table discloses for each important field, and in total, our production volumes for the year ended December 31, 2013 for each product type.

Region	Light and Medium Crude Oil	Heavy Crude Oil	NGLs	Natural Gas	Total
	(bbl/d)	*(bbl/d)*	*(bbl/d)*	*(Mcf/d)*	*(boe/d)*
CANADA					
Southeast Saskatchewan & Manitoba	58,312	-	4,400	26,831	67,184
Southwest Saskatchewan	23,555	176	118	7,047	25,024
Alberta and West Central Saskatchewan	7,675	319	555	22,704	12,333
Total CANADA[(1)]	89,542	495	5,073	56,582	104,540
U.S.					
North Dakota & Montana	4,929	-	199	1,752	5,420
Utah	8,475	-	416	8,618	10,327
Total U.S.[(1)]	13,404	-	615	10,370	15,747
Total[(1)]	**102,946**	**495**	**5,688**	**66,952**	**120,288**

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 six 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 will be held on May 9, 2014.

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
Gregory T. Tisdale Cochrane, Alberta	Chief Financial Officer	Not applicable
C. Neil Smith Calgary, Alberta	Chief Operating Officer	Not applicable
Brad Borggard Calgary, Alberta	Vice President, Corporate Planning	Not applicable
Derek Christie Calgary, Alberta	Vice President, Exploration & Geosciences	Not applicable
Ryan Gritzfeldt Calgary, Alberta	Vice President, Engineering East	Not applicable
Kenneth R. Lamont Calgary, Alberta	Vice President, Finance and Treasurer	Not applicable
Tamara MacDonald Calgary, Alberta	Vice President, Land	Not applicable
Trent Stangl Calgary, Alberta	Vice President, Marketing and Investor Relations	Not applicable
Steven Toews Calgary, Alberta	Vice President, Engineering West	Not applicable
Mark G. Eade Calgary, Alberta	Corporate Secretary	Not applicable
Peter Bannister [1], [3], [4] Calgary, Alberta	Director and Chairman	2003
D. Hugh Gillard [1], [2], [5] Calgary, Alberta	Director	2003
Gregory G. Turnbull [2], [5] Calgary, Alberta	Director	2001
Kenney F. Cugnet [3], [4], [5] Weyburn, Saskatchewan	Director	2003
Gerald A. Romanzin [1], [2], [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 Health, Safety and Environment Committee.
(5) Member of Corporate Governance and Nominating Committee.

As at March 11, 2014, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 4,074,792 Common Shares, representing approximately 1.0% of the issued and outstanding Common Shares. Including restricted shares, ownership increased to 1.4% 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. ("CPEL") 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") and serves on the board of directors of Aston Hill Energy 2010 GP Inc. Mr. Saxberg also served on the board of directors of Bellamont Exploration Ltd., Catapult Energy 2008 Inc. and Wild Stream until the Wild Stream Arrangement was completed. He also serves on the Canadian Associations of Petroleum Producers **("CAPP")** board of governors and on the CAPP Saskatchewan Executive Policy Group. Mr. Saxberg holds a Bachelor of Science degree in mechanical engineering from the University of Manitoba.

Greg Tisdale, Chief Financial Officer

Greg Tisdale is the Chief Financial Officer of Crescent Point, a role he has held with Crescent Point since 2004. He has worked in the oil and gas industry since 1995, having held a variety of roles with companies such as Direct Energy Marketing Ltd., AltaGas Services Inc., Shell Trading Gas and Power Canada Ltd. and Engage Energy Inc.

Mr. Tisdale serves on the board of directors of Enseco Energy Services Corp. and Cardinal Energy Ltd, and served on the Board of Shelter Bay until 2010. He also serves on the board of trustees for the Alberta Cancer Foundation. He is a Chartered Accountant, a member of the Institute of Chartered Accountants of Alberta and a member of the Institute of Corporate Directors. Mr. Tisdale holds a Bachelor of Commerce degree (with distinction) from the University of Alberta.

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. He is 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.

Brad Borggard, Vice President, Corporate Planning

Brad Borggard is the Vice President, Corporate Planning of Crescent Point, a role he has held since January 2010. 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.

Derek Christie, Vice President, Exploration & Geosciences

Derek Christie is the Vice President, Exploration & Geosciences of Crescent Point, a role he has held with Crescent Point since November 2013. Prior to that, he was the Vice President, Geosciences for Crescent Point. He has been with Crescent Point since 2007 and has worked in the oil and gas industry since 1991, having held a variety of roles with companies such as Shelter Bay, Mission Oil and Gas Inc., StarPoint Energy Ltd., Vintage Petroleum Canada Inc. and Rio Alto Exploration Ltd.

Mr. Christie is a member of APEGA and holds a Bachelor of Science degree in Geology from the University of Calgary.

Ryan Gritzfeldt, Vice President, Engineering East

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

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

Ken Lamont, Vice President, Finance and Treasurer

Ken Lamont is the Vice President, Finance and Treasurer of Crescent Point, a role he has held since January 2010. Prior to that, he was Controller and Treasurer for Crescent Point, a role he held from 2005 until 2009. 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 Accountant, as well as a member of the Institute of Chartered Accountants of Alberta.

Tamara MacDonald, Vice President, Land

Tamara MacDonald is the Vice President, Land of Crescent Point, a role she has held with Crescent Point since 2004. 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 Women of Influence. She holds a Bachelor of Commerce degree, with a major in petroleum land management, from the University of Calgary.

Trent Stangl, Vice President, Marketing & Investor Relations

Trent Stangl is the Vice President, Marketing and Investor Relations of Crescent Point, a role he has held since 2008. Prior to that, he was Manager, Marketing and Investor Relations for Crescent Point, a role he held from 2006 until 2008. Mr. Stangl has worked in the oil and gas industry since 1991, having held a variety of roles with companies such as three dimes inc. and Wascana Energy Inc.

Mr. Stangl is a member of the Canadian Investor Relations Institute and the CAPP Markets and Transportation Executive Policy Group. He holds a Bachelor of Arts degree (with honours) in economics from the University of Saskatchewan and a Master of Arts degree in economics from the University of Western Ontario.

Steven Toews, Vice President, Engineering West

Steven Toews is the Vice President, Engineering West of Crescent Point, a role he has held since January 2010. Prior to that, he was Engineering Manager for Crescent Point, a role he held from 2005 until 2009. 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.

Mark Eade, Corporate Secretary

Mark Eade is Corporate Secretary for Crescent Point and was appointed in 2004. He has been a partner with Norton Rose Fulbright Canada LLP (or its predecessor) since August 2011 and prior thereto was a partner at McCarthy Tétrault LLP. Mr. Eade practices in the area of corporate and securities law.

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

Peter Bannister, Director and Chairman

Peter Bannister is Chairman 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. and New Star 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. and Laurasia Resources Ltd. Mr. Bannister holds a Bachelor of Science degree in geology with a minor in economics.

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 (chairman), of Creststreet Power Income Fund and of Point North Energy Ltd. He is a past member of the Management Advisory Council for the University of Calgary, past chairman of the board of Hospice Calgary and is currently a trustee of the Calgary Zoo. He holds a Bachelor of Commerce degree from the University of Calgary and is a graduate of the Stanford Business School Executive Program.

Gregory G. Turnbull, QC, Director

Greg Turnbull is a partner with McCarthy Tétrault LLP law firm in the Calgary office. He has worked as a lawyer since 1979, having held a variety of roles with firms such as Gowlings LLP, Donahue LLP and MacKimmie Matthews. He has been on the board of Crescent Point and its predecessor since 2001.

Mr. Turnbull is also a director of Storm Resources Ltd., Heritage Oil plc, Hawk Exploration Ltd., Hyperion Exploration Corp., Porto Energy Corp., Sonde Resources Corp. and Sunshine Oilsands Ltd. Throughout his career, he has served as an officer or director of many public and private companies. Mr. Turnbull is a member of the Law Society of Alberta, the Canadian Bar Association and the Calgary Bar Association. He holds a Bachelor of Arts degree (with honours) from Queens University and a Bachelor of Law degree from the University of Toronto. He is also the past Chair of the Calgary Zoo.

Kenney F. Cugnet, Director

Since 1963, Ken Cugnet has been the owner and operator of a farm in Weyburn, Saskatchewan, where he lives. He is the president of Valleyview Petroleum and Six Bits Resources Inc., both private oil and gas companies, and has worked in the oil and gas industry since 1962. He has been on the board of Crescent Point and its predecessor since 2003.

Mr. Cugnet also serves as a director of Elkhorn Resources Inc. Formerly, he served as director of Tappit Resources Ltd., Starpoint Energy Inc., Mission Oil and Gas Inc., Medora Resources Inc. and Cypress Petroleum Corp. Also, from 1987 to 1992, Mr. Cugnet was a member of the Saskatchewan Surface Rights Arbitration Board.

Gerald A. Romanzin

Gerald Romanzin is an independent Calgary businessman who serves as a director of Petrowest Corporation, Porto Energy Corp. and of Trimac Transportation Ltd. 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.

Formerly, Mr. Romanzin served as a director of FET Resources Ltd., Ketch Resources Ltd., Ketch Resources Trust, Cadence Energy Inc., Kereco Energy Ltd. and Flowing Energy Corporation. Mr. Romanzin is a Chartered Accountant and he is a member of the Institute of Chartered 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.

D. Hugh Gillard

Mr. Gillard was a director of Point North Energy Ltd. (" **Point North**") from November 2, 2005 until November 22, 2006. In September 2006, Point North filed for, and the Court of Queen's Bench of Alberta granted an initial order to Point North for, creditor protection under the *Companies' Creditors Arrangement Act* due to circumstances arising from events that occurred prior to Mr. Gillard being appointed to the Point North board of directors. In September 2007, a successful plan of arrangement was approved by the creditor of Point North and as a result, Point North emerged from *Companies' Creditors Arrangement Act* protection.

Gregory G. Turnbull

Mr. Turnbull was a director of Action Energy Inc., a corporation engaged in the exploration, development and production of oil and gas in Western Canada. Action Energy Inc. was placed into receivership on October 28, 2009 by its major creditor and Mr. Turnbull resigned as a director immediately thereafter.

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

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.

The DRIP has been in effect since 2010 and remains in effect. However, 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. Effective with the suspension, Shareholders previously enrolled in the premium component of the DRIP began to receive the regular cash dividend amount of $0.23 per share without the 2 percent premium. Shareholders that were enrolled in the premium component of the DRIP when the plan was suspended will remain enrolled at reinstatement and will automatically resume participation in the premium component if, and when, such component is reinstated. The dividend reinvestment portion of the plan remains in effect.

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, 2013, the Corporation is authorized to issue up to 5,728,512 Common Shares, of which the Corporation had 2,588,143 restricted shares outstanding at December 31, 2013.

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 trading 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 trading 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.

Credit Facilities

The Corporation has a $2.0 billion extendible revolving loan facility with a permitted increase (subject to certain conditions) to $2.5 billion (the "**Syndicated Credit Facility**") and a $100 million extendible operating loan facility (the " **Bi-Lateral Credit Facility**"). 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 ("**EBITDA**") ratio. The Credit Facilities are guaranteed by certain material restricted subsidiaries currently being CPEUS, CPUSH, CPHI and the Partnership. The Credit Facilities are unsecured. 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 constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period, subject to a one year term out period should the lender not agree to an annual extension. The Syndicated Credit Facility constitutes a revolving credit facility for a three year term which is extendible annually. The Syndicated Credit Facility does not include a term-out feature. 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.

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 2010, under the five-year re-determination, the FERC set an upward adjustment in the index and determined that the Producer Price Index for Finished Goods plus 2.65% should be the oil pricing index for the five-year period beginning July 1, 2011. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Intrastate crude oil pipeline transportation rates may be subject to regulation by state regulatory commissions. The basis for intrastate pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate crude oil pipeline rates, varies from state to state. Oil exports from Canada may be made pursuant to an export contract with a term not exceeding one year in the case of light crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the National Energy Board ("**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issue of such a licence requires the approval of the Governor in Council. The United States Department of Commerce currently imposes export controls on domestically produced crude oil. A license is required for the export of crude oil to all destinations, including Canada. Only in limited circumstances will the Department of Commerce approve applications to export crude oil, consistent with the regulations of the Bureau of Industry and Security, the agency within the Department of Commerce which reviews such applications, and approval may require a presidential finding before the export can be authorized.

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 licence or order from the NEB or imported into the United States or exported from the United States without a license from the DOE. Licences to export or import natural gas may include various terms and conditions with respect to duration, quantity, tolerance levels, points of exportation or importation, environmental requirements, etc. and, in Canada, may be obtained for a period that does not exceed 25 years. In Canada, the approval of the Governor in Council is required prior to the issuance of a licence by the NEB to import or export natural gas. Alternatively, natural gas can be imported into Canada or exported from Canada pursuant to an order from the NEB. Orders may be obtained for a period of 2 years or less or for a period greater than 2 years but less than 20 years, where the quantity is not more than 30,000 m^3/day. Orders do not require the approval of the Governor in Council. In the United States, the DOE regulates the exportation and importation of natural gas, including liquefied natural gas. U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas; however, the DOE's regulation of imports and exports from and to countries without such free trade agreements is more comprehensive. The FERC also regulates the construction and operation of import and export facilities.

The North American Free Trade Agreement

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.

Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern 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 are determined by negotiations between the mineral owner and the lessee. Crown 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, geographical location, field discovery date and the type or quality of the petroleum product produced.

From time to time, the governments of Canada, Alberta, British Columbia, 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. On February 16, 2007, the Government of Alberta announced a review of the province's royalty and tax regime (including income tax and freehold mineral rights tax) pertaining to oil, natural gas and oil sands to be conducted by a panel of experts, with the assistance of individual Albertans and key stakeholders. The purpose of this process was to ensure that Albertans were receiving a fair share from energy development through royalties, taxes and fees.

On October 25, 2007, the Government of Alberta unveiled a new royalty regime for determining Crown royalty rates in Alberta (the " **Royalty Framework**"), effective January 1, 2009. The Royalty Framework introduced new royalties applicable to all conventional oil and natural gas wells and bitumen production, with the exception of those subject to the transitional royalty rate discussed below.

The Royalty Framework eliminated the previous tier system for conventional oil, which was based on the vintage or discovery date of the oil, and implemented a sliding rate formula based on both the commodity price of oil and well production. Subject to certain available incentives, effective from the January 2011 production month royalty rates for conventional oil production under the Royalty Framework range from a base rate of 0% to a cap of 40%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011. Actual royalty rates are determined on a monthly basis.

The Royalty Framework also eliminated the previous tier system for natural gas, which was also based on the vintage or discovery date of the gas, and implemented a sliding rate formula based on both the commodity price of the gas and well production. This eliminated the option to use a corporate average reference price. The natural gas royalty formula also provides for a reduction based on the measured depth of the well below 2,000 metres (the "**Depth Factor Adjustment**"), as well as the acid gas content of the produced gas (the " **Acid Gas Adjustment**"). Subject to certain available incentives, effective from the January 2011 production month royalty rates for natural gas production under the Royalty Framework range from a base rate of 5% to a cap of 36%. This represents an increase from the previous rate cap of 35% under the tier system, but a decrease from the rate cap of 50% under the Royalty Framework prior to January 2011.

Under the Royalty 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.

Transitional Incentive

In late November 2008, the Alberta government announced details of an optional five-year transitional royalty program (the " **Transitional Program**") applicable to conventional oil and natural gas wells drilled to measured depths from 1,000 to 3,500 metres, with a spud date on or after November 19, 2008. For each eligible well, the producer could make a one-time election to produce the well under the Transitional Program royalty rates or the Royalty Framework rates. The Transitional Program royalty rates would only apply to production from January 1, 2009 until December 31, 2013. As of January 1, 2014, all production subject to the Transitional Program reverted to the Royalty Framework regime. Operators electing the Transitional Program rates are not eligible for the Depth Factor Adjustment or the Acid Gas Adjustment, which are specific to the Royalty Framework, but are otherwise not excluded from available incentive programs, subject to eligibility as discussed below. On March 11, 2010, the Government of Alberta announced that the Transitional Program would continue until its originally announced expiration, however, effective January 1, 2011, no new wells would be eligible for the selection of the Transitional Program royalty rates. Wells which had already opted for the Transitional Program royalty rates prior to January 1, 2011 had the option to continue under the Transitional Program royalty rates until the expiry of the Transitional Program, or to opt out of the Transitional Program by February 15, 2011 in favour of the Royalty Framework rates.

Incentive Programs

The Royalty Framework also eliminated some previously available incentives, and introduced certain revised or updated incentive programs.

With respect to conventional oil, the Royalty Framework eliminated the Third Tier Exploratory Well Royalty Exemption, the Re-activated Well Royalty Reduction, the Low Productivity Well Royalty Reduction, the Horizontal Re-entry Well Royalty Program, and the Experimental Project Petroleum Royalty.

With respect to natural gas, the Royalty Framework eliminated the Deep Gas Royalty Holiday and the Royalty Adjustment Program for Deep Marginal Gas Wells.

Pursuant to the Royalty Framework, the Deep Oil Exploratory Well Program, the Enhanced Recovery of Oil Royalty Reduction Program (" **EOR Program**"), the Natural Gas Deep Drilling Program, and the Innovative Energy Technologies Program (the " **IETP**") were either created or retained.

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. Existing oil wells approved under the discontinued Third Tier Exploratory Well Royalty Exemption and qualifying for the Deep Oil Exploratory Well Program were transitioned into the new program on January 1, 2009.

With respect to the EOR Program, the Enhanced Recovery of Oil Royalty Reduction Regulation provides that Alberta Energy may approve royalty reductions for qualifying enhanced oil recovery projects.

The Natural Gas Deep Drilling Regulation, 2010 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened between May 1, 2010 and December 31, 2013 (inclusive), with producing intervals that are deeper than 2,000 metres.

The IETP was originally intended to promote producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. This program had been retained under the Royalty Framework. 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.

On March 3, 2009, the Government of Alberta announced an additional incentive program, the Drilling Royalty Credit (the " **DRC**"), in respect of conventional oil and gas wells drilled on Alberta Crown lands. On June 25, 2009, the Government of Alberta announced the extension of the DRC for one additional year, expiring on April 1, 2011. The Drilling Royalty Credit Regulation provided that for qualifying wells drilled for the purpose of extracting conventional oil or natural gas and with a spud date and finish drill date between April 1, 2009 and April 1, 2011, the operator would receive a royalty credit of $200 per metre drilled, up to a prescribed maximum percentage of the operator's royalties. The maximum percentage was determined on a sliding scale ranging from 10% to 50%, based on the operator's production, with a higher maximum percentage available to lower producing operators. The DRC was only available to companies that would be recognized as having royalty payment obligations pursuant to applicable regulation. Any DRC royalty credits not used prior to March 31, 2011 were forfeited.

On March 3, 2009, the Government of Alberta also announced the New Well Royalty Reduction (the " **NWRR**") incentive program. The New Well Royalty Reduction Regulation provided that the NWRR would be available to qualifying wells that commence or recommence producing conventional oil or natural gas between April 1, 2009 and April 30, 2010. Pursuant to the New Well Royalty Reduction Regulation, royalties on production from qualifying wells were reduced to a maximum royalty rate of 5% until the earlier of either 12 production months from the date of first production, the date that the production cap was met (for natural gas wells, 7,949 m^3 of oil equivalent (500 MMcf of gas) and for conventional oil 7 ,949 m^3 of oil or oi equivalent), the date the well becomes part of a Project under the Oil Sands Royalty Regulation, 2009, or March 31, 2012, whichever occurred first. On March 11, 2010, as part of a larger modification of royalty rates under the Royalty Framework, the Government of Alberta announced that the NWRR was to become a permanent feature of Alberta's royalty regime, and the New Well Royalty Regulation was enacted. Pursuant to the New Well Royalty Regulation, production from a qualifying well is calculated at royalty of 5% until either the end of the eligible production month cap of the well, the date that the volume cap is reached for that well or the date the well becomes part of a Project under the Oil Sands Royalty Regulation, 2009, whichever occurs first.

In addition, on May 27, 2010 the Government of Alberta announced further initiatives to stimulate investment in emerging resources and technologies. In particular, the Horizontal Gas New Well Royalty Rate ("**HGNWRR**") reduces royalties on production from qualifying wells to a maximum royalty rate of 5% until the earlier of either 18 production months from date of first production or the date that the first 7,949 m^3 of oil equivalent is produced. Finally, the Horizontal Oil New Well Royalty Rate ("**HONWRR**") reduces royalties on production from qualifying wells to a maximum royalty rate of 5% until the prescribed time or volume limit is met. The time and volume limits increase with the depth of metres drilled, from a minimum of 7,949 m^3 of oil equivalent and 18 months for wells drilled to measured depths from 0 to 2,499 metres, to a maximum of 15,899 m^3 of equivalent and 48 months for wells drilled to measured depths in excess of 4,500 metres. The NWRR applies retroactively to production produced on or after May 1, 2010. The HGNWRR and HONWRR apply retroactively to spud dates on or after May 1, 2010.

Both the DRC and NWRR apply to wells under the Royalty Framework as well as those wells electing the Transitional Program rates. In relation to conventional oil wells eligible for both the NWRR and the Deep Oil Exploratory Well Program, the date constraints and volume limits under each program will run concurrently. In relation to natural gas wells eligible for both the NWRR and the NGDDP and any of the 5% royalty rates, including the HGNWRR, the Coal Bed Methane NWRR or the Shale Gas NWRR, the 5% royalty rate will be applied first, with the NGDDP benefits applied after the expiration of the 5% rate. However, the 60 calendar month benefit under the NGDDP begins on the well's finished drilling date, not with the expiry of the 5% royalty rate. In addition, the NWRR will reduce the royalty reduction that is available for wells under the EOR Program and the IETP.

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" (introduced October 1, 2002), "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 Energy and Resources ("**SER**"), 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 produced from gas wells and the latter being produced from oil wells. Additionally, the gas is divided according to the royalty and production tax classifications as either "fourth tier gas" (introduced October 1, 2002), "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%. Subject to certain restrictions, the operator may elect to use either a prescribed reference price determined monthly by SER, or a reference price based on the operator's average gas price in a month. 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.

On June 14, 2010 the SER released a letter outlining significant changes to the current administrative provisions under the government's Process Renewal and Infrastructure Management Enhancements ("**PRIME**") initiative. Among other changes, PRIME seeks to modernize Saskatchewan's well facility program, and to allow industry to electronically submit information and to access government services through a web-based self-serve application.

Natural gas is generally bought and sold on an energy basis. To eliminate existing equity issues related to the current volumetric based royalty/tax calculation, the SER will be converting to an energy based calculation. Consequently, the price used to value natural gas production for royalty/tax purposes will be expressed in dollars per gigajoule. These new provisions were implemented in April, 2012.

Incentives

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%. Horizontal gas wells drilled between June 1, 2010 and March 31, 2013 inclusive are also classified as qualifying exploratory gas wells for royalty/tax purposes and 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 revenue 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 April of 2013, the SER 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 a 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, depending on depth. The HWD is very similar to the VWD but, applies to non-exploratory horizontal wells 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.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate (" **RTR**") as a response to the federal government disallowing the deduction of crown royalties and similar taxes as a business expense for income tax purposes. As of January 1, 2007, the RTR was allowed to wind down as a result of the federal government's initiative to reintroduce the full deduction of crown royalties in computing income for federal and provincial income tax purposes in respect of taxation years commencing after 2006. Commencing January 1, 2007, the carry forward period for any outstanding RTR balance was limited to 7 years.

Manitoba

Provincial Crown Royalties and Freehold Production Tax

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 drilled prior to April 1, 1974 that does not qualify as new oil or third tier 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 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. 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.

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.

Incentives

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" pursuant to which no Crown royalties or freehold production taxes are payable until the holiday oil volume has been produced. Under the Program, wells drilled for purposes of injection (or wells converted to injection prior to producing predetermined volumes of oil) in an approved enhanced oil recovery project earn a one-year holiday for portions of the project area.

The Program consists of the following components:

- *New Well Incentive* provides licensees of newly drilled, non-horizontal wells drilled prior to January 1, 2014 with a maximum holiday oil volume of 10,000 m^3;

- *Deep Drilling Incentive* provides licensees who drill a well to the base of the Devonian Duperow formation with a holiday oil volume of 20,000 m^3, and licensees who drill a well deeper than the Devonian Three Forks formation can make a one-time assignment of up to 10,000 m^3 of holiday oil volume earned through previous drilling or major workovers to such well's holiday oil volume;

- *Horizontal Well Initiative* provides licensees of horizontal wells drilled on or after January 1, 2009 and prior to January 1, 2014 with a holiday oil volume of 10,000 m^3, and a horizontal leg drilled from an existing horizontal well on or after January 1, 2009 and prior to January 1, 2014 will earn an additional holiday royalty volume of 3,000 m^3;

- *Marginal Well Major Workover Incentive* provides licensees of marginal wells where a major workover is completed on or after January 1, 2009 and prior to January 1, 2014 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 1 m^3 per operating day;

- *Injection Well Incentive* provides a one year exemption from the payment of Crown royalties or freehold production taxes on production allocated to a unit tract in which a well is drilled or converted to water injection;

Further, holiday oil volumes earned by a newly drilled well, or a marginal well that has undergone a major workover can be transferred to a "holiday oil volume account" at the request of the licensee, the purpose of which is to optimize the value of holiday oil volumes earned by providing a company with the flexibility of allocating holiday oil volumes earned among new wells. However, effective January 1, 2015, holiday oil volume accounts will be eliminated by the Manitoba Ministry of Innovation, Energy and Mines. Until December 31, 2014, a holder of an account will be able to make a one-time transfer of 2,000m^3 of holiday oil to a well drilled during the period January 1, 2014 to December 31, 2014. For the period of January 1, 2014 to January 1, 2015, holiday oil volume may not be transferred from individual wells to the account.

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 and regulations. 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 requirements with respect to oilfield waste handling, storage and disposal, land reclamation, habitat protection, and minimum setbacks of oil and gas activities from surface water bodies.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation 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. For example, regulations enacted thereunder target sulphur dioxide and nitrous oxide emissions from oil and gas operations. Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the Environmental Management and Protection Act, 2002 and the Oil and Gas Conservation Act, which regulate harmful or potentially harmful activities and substances, any release of such substances, and remediation obligations in Saskatchewan. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or 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 *Environmental Act* and the *Oil and Gas Act*, which require certain advanced exploration projects to submit a proposal to Manitoba Conservation .

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.

As at December 31, 2013, Crescent Point owned approximately 19,498 gross (11,881 net) wells, for which abandonment and reclamation costs are expected to be incurred. During the 2013 financial year, Crescent Point spent approximately $11.4 million on well abandonments and environmental remediation activities. Crescent Point estimates that it will spend approximately $18.5 million on well abandonments and environmental remediation and reclamation activities in 2014, and has budgeted accordingly. Crescent Point has estimated the net present value (discounted at approximately 3.0 percent per annum) of its total decommissioning liability (wells and facilities) to be approximately $629.5 million as at December 31, 2013, based on a future liability (inflated at 2 percent per annum) of approximately $1.0 billion. 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 Alberta Energy Regulator ("**AER**") and the Saskatchewan Energy and Resources Ministry ("**SER**") Licensee Liability Rating Guidelines ("**LLRG**"). Crescent Point has a detailed environmental policies and procedures manual which addresses various topics including: spill prevention, response, notification, reporting 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 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.

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.

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 Environmental Protection Agency (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.

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, was introduced during the previous session of Congress and may be reintroduced during the current session of Congress. In addition, the EPA at the request of Congress is currently conducting a national study examining the potential impacts of hydraulic fracturing on drinking water resources, with a draft of the final report expected to be released in 2014.

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. If new federal or 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. On April 17, 2012, the EPA issued final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations within federal regulatory jurisdiction to regulation under the New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants programs. The EPA rules include New Source Performance Standards for completions of hydraulically fractured wells. The final rules establish a phase-in period that will ensure that manufacturers have time to make and broadly distribute the required emissions reduction technology.

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 Emitters Regulation* pursuant to the *Climate Change and Emissions Management Act*. These regulations require Alberta facilities that emit more than 100,000 tonnes of GHG per year to reduce emissions intensity by 12% below an average baseline taken from a facility's 2003 - 2005 emissions. Companies may meet requirements through improvements to their operations; by purchasing Alberta based emission reduction 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. The Province of Alberta also published a climate change action plan in January of 2008 wherein it set an objective to deliver a 50% reduction in GHG emissions from business as usual by 2050 by employing: (a) mandatory carbon capture and storage ("CCS") for certain facilities; (b) energy efficiency and conservation; and (c) research and investment in clean energy technologies, including carbon separation technologies to assist CCS.

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 received Royal Assent on May 20, 2010 and will come into force on proclamation. Draft versions of the regulations under the MRGHGA indicate that Saskatchewan will adopt similar initiatives to the Alberta framework. The *Management and Reduction of Greenhouse Gases Act* establishes the provinces' strategy to meet its target of reducing GHG emissions. Baseline emissions and reduction targets will be set by the Lieutenant Governor in Council. Crescent Point is involved in the re-development of the proposed Saskatchewan environmental protection legislation and is currently working with the Government of Saskatchewan. No financial and operational effects of the proposed legislation are currently known due to its preliminary nature.

In British Columbia, GHG emissions are regulated under the Reporting Regulation enacted pursuant to the *Greenhouse Gas Reduction (Cap and Trade) Act*. Starting January 1, 2010, these regulations impose GHG emissions reporting requirements upon B.C. facilities emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year. In addition, facilities reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. To date, Crescent Point does not operate any facilities that are regulated by the British Columbia GHG emissions regulations.

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, particularly in B.C. where a cap and trade regime is pending. In the near term, Crescent Point does not expect to have any facilities subject to reporting based on these preliminary 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. The Kyoto Protocol officially came into force on February 16, 2005, although on December 12, 2011, Canada formally withdrew from the Kyoto Protocol. However, the Canadian federal government has indicated an intention to regulate the emissions of GHGs from a range of industries in its framework and has outlined a number of policies to reduce GHGs intensity of regulated facilities (the "Federal Plan"). New facilities (which are defined as those facilities whose first year of operation is 2004 or later) would face intensity reduction requirements beginning in their fourth year of commercial production, of 2% per year from their "baseline" emissions intensity (which baseline is the emissions intensity for such facility's third year of commercial production) until at least 2020. Compliance options for new facilities under the Federal Plan include making emissions intensity improvements; making investments in certified carbon capture and storage projects; buying offsets or emissions performance credits; and for a portion of each entity's emissions reduction obligations, making payments of $15 per tonne until 2012, $20 per tonne in 2013 and ar escalating annual rate per tonne thereafter; to the federal technology fund.

The Federal Plan also includes proposed requirements to be implemented by the Canadian federal government which would govern the emission of industrial air pollutants. Certain of the proposed requirements include fixed emissions caps, an emissions credit trading system, and several options from which companies can choose to meet their GHG emission reduction targets. At present, the status of its proposals is unclear. The Canadian federal government has repeatedly stated that it intends to align Canada's GHG emission reduction policies with those of the United States, and it is willing to wait until the United States has developed its framework before implementing any policies in Canada. As such, it is unclear when, or in what form, the Federal Plan will be implemented.

Several of the provinces and territories are working together with various American states to develop a cap and trade system. It remains to be seen whether the Canadian federal government would adopt such an approach, but given its statements regarding aligning policy with the United States, this will likely depend on whether the United States adopts a cap and trade system. No assurance can be given that either a modified Federal Plan or a North American cap and trade system will or will not be implemented, or what kinds of obligations may be imposed under such a system.

At the July 2009 G8 Summit in Italy, Canada and the other G8 members agreed to work together toward achieving at least a 50% reduction of global GHG emissions by 2050. Canada reiterated its commitment to this goal at the June 2010 G8 Summit in Huntsville, Ontario.

In December 2009, Canada participated in the Fifteenth session of the Conference of the Parties to the United Nations Framework Convention on Climate Change ("**COP 15**") in Denmark, the goal of which was to reach a new agreement for fighting global climate change. COP 15 resulted in the non-binding Copenhagen Accord, whereby Canada and the other participating countries committed to implementing quantified economy-wide emissions targets by 2020. Canada submitted its GHG emission reduction targets on January 30, 2010, noting that: (a) its target is a 17% reduction from a baseline of 2005 emission levels (which target is aligned with the final economy-wide emissions target and base year of the United States); and (b) its submission is dependent on the other parties to the Copenhagen Accord submitting emissions targets and mitigation actions in accordance with such Accord.

There remains ongoing uncertainty regarding Canada's short-term and long-term emissions reduction targets and whether such targets will be absolute or intensity based. Facility owners across Canada await further information regarding Canada's approach to regulating GHG emissions. Although the timing and nature of federal GHG regulations are unknown at this time, Crescent Point anticipates that, based on current production levels, 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 reduction requirements and to perform necessary monitoring, measurement, verification, and reporting of GHG emissions.

As part of its ongoing commitment to reduce GHG emissions, Crescent Point established an Environmental Emissions Reduction Fund in 2007. During 2013, $0.30 per produced boe was allocated to this fund. As at December 31, 2013, $44.6 million has been allocated to the fund and $24.5 million has been expended in order to reduce GHG emissions and to meet and exceed provincial and proposed federal targets.

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.

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 however that environmental laws will not result in a curtailment of production or a material increase in the costs of production, the development or exploration activities, or otherwise adversely affect Crescent Point's financial condition, capital expenditures, results of operations, competitive position or prospects.

RISK FACTORS

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

Risks Relating to Our Business

Our estimated Proved and Proved plus Probable reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions 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. 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. 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.

Reinvestment of Cash Flow to Fund Ongoing Operations

Dividends may be reduced 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, and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could 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 generally do not actively explore for oil and natural gas reserves. 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 also distribute approximately 50% of our net cash flow to Shareholders rather than reinvesting it in reserve additions. Accordingly, if external sources of capital, including the issuance of additional Common Shares, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves will be impaired. To the extent that we are required to use cash flow to finance capital expenditures or property acquisitions, the level of cash flow available for payment of dividends to Shareholders will be reduced. Additionally, 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 will 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.

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 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.

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.

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, 2013, approximately 15% 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, such as Shareholders, for losses sustained or liabilities incurred, except for liabilities that may result from gross negligence or willful misconduct.

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

Delays in business operations could adversely affect dividends to Shareholders 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 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 the amount of cash available for dividends to Shareholders in a given period and expose us to additional third party credit risks.

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

Although the Corporation monitors the credit worthiness of third parties it contracts with through a formal Risk Management and Counterparty Credit Policy and maintains third party 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 result in 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.

The Corporation maintains trade credit insurance to partially protect against credit risk with financial counterparties.

Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, 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 Credit Facilities provide that if we are in default under the Credit Facilities 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.

If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may receive a judgment and have an unsecured claim on the properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for dividends to Shareholders.

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. We currently have a syndicated $2.0 billion extendible revolving loan facility with a permitted increase to $2.5 billion (subject to certain conditions) (the "**Syndicated Credit Facility**") with certain banks and a $100 million operating loan facility with one Canadian chartered bank. The interest charged on the Syndicated Credit Facility is calculated based on a sliding scale ratio of the Corporation's senior debt to 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.

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.

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 60% of Crescent Point's Utah assets are located on the Reservation. 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.

Increased costs of capital could adversely affect our business.

Our business and operating results can 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.

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.

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

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

We 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. Investors should carefully consider whether they are willing to rely on the existing management before investing in the Common Shares.

Risks Relating to the Oil and Gas Industry

Natural gas and oil 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 natural gas and oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results and could result in an impairment charge.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, 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 natural gas and oil supply and demand and expectations regarding supply and demand;
- the level of consumer product demand;
- weather conditions;
- political conditions or hostilities in natural gas and oil 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 natural gas and oil;
- 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 natural gas and crude oil. If natural gas and crude oil prices decline significantly 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 historical 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 unfavorable exchange rate changes to the extent of our investment in U.S. subsidiaries and to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

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

The oil and natural gas industry is highly competitive. We compete for capital, acquisitions of reserves, undeveloped lands, skilled personnel, access to drilling rigs, service rigs and other equipment, access to processing facilities, pipeline and refining capacity and in many other respects with a substantial number of other organizations, many of which may have greater technical and financial resources than we do. Some of these organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a worldwide basis. As a result of these complementary activities, some of our competitors may have greater and more diverse competitive resources to draw on than we do. Given the highly competitive nature of the oil and natural gas industry, this could adversely affect the market price of our Common Shares and 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 and spills. 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 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, we could be liable for personal injuries, property damage and other damages. Failure to comply with these laws also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Moreover, these laws 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, 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, which could be material. The operational hazards associated with possible blowouts, accidents, oil spills, gas leaks, fires, 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 environmental damage or contamination 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 or by a prior owner or tenant, or by 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 compliance costs, if enacted. 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. 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 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 Tribe 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. Environmental Protection Agency, 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.

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. Further, facilities required to obtain PSD permits for their GHG emissions are required to reduce those emissions 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 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, 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 recently been the subject of greater regulatory 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 review 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.

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

In response to recent train derailments occurring in the United States and Canada in 2013, U.S. regulators are implementing or considering new rules to address the safety risks of transporting crude oil by rail. On January 23, 2014, the National Transportation Safety Board issued a series of recommendations to address safety risks, including (i) requiring expanded hazardous material route planning for railroads to avoid populated and other sensitive areas, (ii) to develop an audit program to ensure rail carriers that carry petroleum products have adequate response capabilities to address worst-case discharges of the entire quantity of product carried on a train, and (iii) to audit shippers and rail carriers to ensure they are properly classifying hazardous materials in transportation and that they have adequate safety and security plans in place. Additionally, on February 25, 2014 the U.S. Department of Transportation issued an emergency order requiring all persons, prior to offering petroleum crude oil into transportation, to ensure such product is properly tested and classed and to assure all shipments by rail of petroleum crude oil be handled as a Packing Group I or II hazardous material. Such tests help determine how likely the fuel is to ignite and dictate what type of rail car can be used for shipment. The introduction of these or other regulations that result in new requirements addressing the type, design, specifications or construction of rail cars used to transport crude oil could result in severe transportation capacity constraints during the period in which new rail cars are retrofitted or constructed to meet new specifications. On March 6, 2014, the U.S. Department of Transportation issued an amended emergency order, offering more details on testing requirements of oil transported by rail and cautioned companies against circumventing the rules. The amended emergency order offers new standards on how frequently testing of crude oil has to be done. Testing must now be conducted within the reasonable, recent past to determine the flash point and boiling point of crude oil. The amended emergency order also warns companies not to re-label crude as a more generic category of flammable liquid in an attempt to get around the testing.

We do not currently own or operate rail transportation facilities or rail cars; however, the adoption of any regulations that impact the testing or rail transportation of crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout Canada and the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

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

Changes in tax and other laws may adversely affect the trading price of our Common Shares and 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.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated or deferred as a result of future legislation.

In April 2013, President Obama's Administration released its proposed federal budget for fiscal year 2014 that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. Such changes include, but are not limited to:

- the repeal of the percentage depletion allowance for oil and gas properties;
- the elimination of current deductions for intangible drilling and development costs;
- the elimination of the deduction for U.S. oil and gas production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations.

In connection with the passage of the Dodd-Frank Wall Street Reform and Consumer Protection Act, new regulations forthcoming in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to manage our risks related to oil and gas commodity price volatility.

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was enacted into law. This financial reform legislation includes provisions that require over-the-counter derivative transactions to be executed through an exchange or centrally cleared. In addition, the legislation provides an exemption from mandatory clearing requirements based on regulations to be developed by the Commodity Futures Trading Commission (the "**CFTC**") and the U.S. Securities and Exchange Commission ("**SEC**") for transactions by non-financial institutions to hedge or mitigate commercial risk. At the same time, the legislation includes provisions under which the CFTC may impose collateral requirements for transactions, including those that are used to hedge commercial risk. However, during drafting of the legislation, members of Congress adopted report language and issued a public letter stating that it was not their intention to impose margin and collateral requirements on counterparties that utilize transactions to hedge commercial risk. Final rules on major provisions in the legislation, like new margin requirements, will be established through rulemakings and will not take effect until 12 months after the date of enactment. Although we cannot predict the ultimate outcome of these rulemakings, new regulations in this area may result in increased costs and cash collateral requirements for the types of oil and gas derivative instruments we use to hedge and to otherwise manage our financial risks related to volatility in oil and gas commodity prices.

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 and unexpected weather patterns 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

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 dependant 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 do not reinvest a material portion of our cash flow, our success is, in part, dependent 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.

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.

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.

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 prevailing economic and competitive environment, results of operations, fluctuations in working capital, the price of oil and gas, 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 2013, the Corporation's payout ratio on a per Common Share diluted basis was 52%.

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 2011 - December 2011	$0.23
January 2012 - December 2012	$0.23
January 2013 - December 2013	$0.23

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)
2013			
January	40.05	35.93	34,800
February	39.60	38.06	20,044
March	39.99	37.91	22,707
April	38.74	34.53	26,709
May	38.97	37.21	21,618
June	37.50	35.25	24,935
July	39.79	35.28	24,498
August	39.85	37.73	23,466
September	39.32	37.22	19,689
October	40.98	37.93	19,784
November	41.24	39.19	18,154
December	41.60	39.73	20,352
2014			
January	41.14	37.85	24,709
February	39.59	37.32	20,533

NYSE	High (US$)	Low (US$)	Volume (000's)
2014			
January (22-31)	38.36	34.18	461
February	35.92	33.72	956

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. Greg Turnbull, a director of the Corporation, is a partner of McCarthy Tétrault LLP and Mr. Mark Eade, an officer of the Corporation, is a partner of Norton Rose Fulbright Canada LLP, both law firms that provide services to the Corporation and its subsidiaries. The board of directors of the Corporation do not believe that any of the activities undertaken by either of Messrs. Turnbull or Eade or by McCarthy Tétrault LLP or Norton Rose Fulbright Canada LLP interfere, or could be perceived to interfere, in any material way with their 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 three members: Gerald A. Romanzin (Chair), D. Hugh Gillard and Peter N. Bannister, 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 their 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 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	Gerald Romanzin is an independent Calgary businessman who serves as a director of Petrowest Corporation, Porto Energy Corp. and of Trimac Transportation Ltd. 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 since 2004. Formerly, Mr. Romanzin served as a director of FET Resources Ltd., Ketch Resources Ltd., Ketch Resources Trust, Cadence Energy Inc., Kereco Energy Ltd. and Flowing Energy Corporation. Mr. Romanzin is a chartered accountant has held a number of senior roles with the Alberta Stock Exchange and, subsequent to its conversion, with the TSX Venture Exchange. He is a member of the Institute of Chartered Accountants of Alberta and holds a Bachelor of Commerce degree from the University of Calgary.
D. Hugh Gillard	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 and Amoco Canada. Mr. Gillard has been on the board of Crescent Point since 2003. Mr. Gillard has served as director of the board of Petrowest Energy Services Trust (chairman), of Creststreet Power Income Fund and of Point North Energy Ltd. He is a past member of the Management Advisory Council for the University of Calgary, past chairman of the board of Hospice Calgary and is currently a trustee of the Calgary Zoo. He holds a Bachelor of Commerce degree from the University of Calgary and is a graduate of the Stanford Business School Executive Program.
Peter N. Bannister	Peter Bannister is Chairman 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, 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. and New Star 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. and Laurasia Resources Ltd. Mr. Bannister holds a Bachelor of Science degree in geology with a minor in economics.

External Auditor Services Fees

For services provided to the Corporation and its subsidiaries the years ended December 31, 2013 and 2012 PricewaterhouseCoopers LLP billed approximately $812,281 and $863,305, respectively, as detailed below:

	Year ended December 31	
	2013	2012
PricewaterhouseCoopers		
Audit fees	$ 772,418	$ 584,805
Audit-related fees[(1)]	$ 20,300	$ 278,500
Tax Fees	$ -	$ -
All other fees	$ 19,563	$ -
Total	$ 812,281	$ 863,305

Note:

(1) Fees include the costs related to public financings and related reporting to regulators.

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 and quarterly financial statements and Management's Discussion and Analysis. 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

Our auditors are PricewaterhouseCoopers LLP, Chartered Accountants, 3100, 111 – 5th Avenue S.W., Calgary, Alberta, T2P 5L3. The transfer agent and registrar for our Common Shares is Olympia Trust Company in Calgary, Alberta.

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, 2013, 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 Institute of Chartered 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, is contained in our information circular in respect of the annual and special meeting of Shareholders held on May 9, 2014. 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, 2013.

For additional copies of this AIF please contact:

Crescent Point Energy Corp.
2800, 111 – 5th Avenue, S.W.
Calgary, Alberta
T2P 3Y6

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 Company staff members as applicable.

Delegation

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

Annual Audit Committee Plan

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

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

Committee Expectations and Information Needs

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

Access to Independent Advisors

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

Reporting to the Board, Shareholders and Others

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

Evaluation

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

Access to the Committee

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

The External Auditors

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

No Alteration

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

2. Operating Procedures

Meetings

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

Quorum

A quorum shall be a majority of the Members.

Notice of Meeting

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

Meeting Agenda

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

Procedure, Records and Reporting

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

In Camera Meetings

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

Referral to the Board

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

Secretary

Unless the Committee otherwise specifies, the Corporate Secretary (or his or her deputee) of the Corporation shall act as Secretary of all meetings of the Committee.

Acting Chair

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

Minutes

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

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 Company internal control processes or indications which may suggest fraud and the corrective activity undertaken in respect thereto; and

(c) Institute a procedure that will permit any employee, including management employees, to bring to the attention of the Board or the Committee concerns relating to financial controls and reporting which are material in scope and which cannot be addressed, in the employee's 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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation 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	Corporate Evaluation January 30, 2014	Canada	-	3,057,865	-	3,057,865

5. 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.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. 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 March 11, 2014

ORIGINALLY SIGNED BY

Terry L. Aarsby, 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"):

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   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2013, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator	Description and Preparation 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 - Cdn. $M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	U.S.A. Summary January 30, 2014	U.S.A.	-	1,559,740	-	1,559,740

5. 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.

6. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

7. 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 March 11, 2014

ORIGINALLY SIGNED BY

Terry L. Aarsby, 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, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, 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.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. 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.

4. The following table sets forth the estimated 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 by us for the year ended December 31, 2013, 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:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of Certain Saskatchewan P&NG Reserves of Crescent Point Energy Corp., As of December 31, 2013, prepared August 2013 to February 2014	Canada				
Total			Nil	10,972,392	Nil	10,972,392

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented 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.

6. We have no responsibility to update the report referred to in paragraph 4 for events and circumstances occurring afters its preparation date.

7. 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:

Sproule Associates Limited, Calgary, Alberta Dated February 5, 2014

ORIGINALLY SIGNED BY

Richard A. Brekke, P. Eng.
Manager, Engineering and Partner

Vincent K. Hui, P. Eng.
Petroleum Engineer and Partner

Alec Kovaltchouk, P.Geo.
Manager, Geoscience and Partner

Ian K. Kirkland, P.Geol.
Senior Petroleum Geologist and Partner

Harry J. Helwerda, P. Eng., FEC, FGC (Hon.)
President & Chief Operating Officer 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, which consist of the following:

(a) Proved and Proved plus Probable oil and gas reserves estimated as at December 31, 2013 using forecast prices and costs; and

(b) the related estimated future net revenue.

GLJ Petroleum Consultants and Sproule Associates Limited, each an independent qualified reserves evaluator 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

March 11, 2014

Exhibit 99.2

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL REPORTING

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

Management has developed and maintains an extensive system of internal accounting controls that provide reasonable assurance that all transactions are accurately recorded, that the consolidated financial statements realistically report the Company's operating and financial results, and that the Company's assets are safeguarded. Management believes that this system of internal controls has operated effectively for the year ended December 31, 2013. The Company has effective disclosure controls and procedures to ensure timely and accurate disclosure of material information relating to the Company which complies with the requirements of Canadian securities legislation.

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

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



Scott Saxberg
President and Chief Executive Officer



Greg Tisdale
Chief Financial Officer

March 11, 2014

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Crescent Point Energy Corp.

We have audited the accompanying consolidated financial statements of Crescent Point Energy Corp. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2013 and December 31, 2012 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and the related notes, which comprise a summary of significant accounting policies and other explanatory information.

Management's responsibility for the consolidated financial statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Crescent Point Energy Corp. and its subsidiaries as at December 31, 2013 and December 31, 2012 and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

(signed)

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
March 11, 2014

CONSOLIDATED BALANCE SHEETS

As at December 31			
(Cdn$000s)	Notes	**2013**	2012
ASSETS			
Cash		**15,941**	-
Accounts receivable		**352,519**	301,770
Prepaids and deposits		**5,532**	8,484
Derivative asset	22	**3,126**	19,457
Total current assets		**377,118**	329,711
Long-term investments	5	**74,229**	84,906
Derivative asset	22	**48,098**	42,241
Other long-term assets	6	**37,958**	22,232
Exploration and evaluation	7, 8	**688,324**	1,080,757
Property, plant and equipment	8, 9	**11,259,147**	10,319,868
Goodwill	10	**251,919**	251,919
Total assets		**12,736,793**	12,131,634
LIABILITIES			
Accounts payable and accrued liabilities		**789,305**	655,191
Dividends payable	13	**90,849**	86,182
Derivative liability	22	**99,388**	15,349
Decommissioning liability	12	**18,469**	-
Total current liabilities		**998,011**	756,722
Long-term debt	11	**1,734,114**	1,474,589
Derivative liability	22	**25,846**	8,483
Long-term compensation liability	20	**3,072**	1,931
Decommissioning liability	12	**611,069**	502,432
Deferred income tax	19	**864,608**	792,665
Total liabilities		**4,236,720**	3,536,822
SHAREHOLDERS' EQUITY			
Shareholders' capital	13	**11,990,305**	11,249,168
Contributed surplus		**109,564**	102,755
Deficit	14	**(3,692,437)**	(2,755,832)
Accumulated other comprehensive income (loss)		**92,641**	(1,279)
Total shareholders' equity		**8,500,073**	8,594,812
Total liabilities and shareholders' equity		**12,736,793**	12,131,634

Commitments (Note 24)

See accompanying notes to the consolidated financial statements.

Approved on behalf of the Board of Directors:



Gerald A. Romanzin
Director



D. Hugh Gillard
Director

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

For the years ended December 31			
(Cdn$000s, except per share amounts)	Notes	**2013**	2012
REVENUE AND OTHER INCOME			
Oil and gas sales		**3,526,448**	2,694,994
Royalties		**(644,240)**	(468,226)
Oil and gas revenue		**2,882,208**	2,226,768
Derivative gains (losses)	16, 22	**(202,747)**	168,120
Other loss	17	**(10,064)**	(60,455)
		2,669,397	2,334,433
EXPENSES			
Operating		**505,060**	421,125
Transportation		**95,317**	66,147
General and administrative		**67,466**	63,384
Interest on long-term debt		**77,754**	71,530
Foreign exchange (gain) loss	18	**64,505**	(2,792)
Share-based compensation	20	**67,752**	51,141
Depletion, depreciation, amortization and impairment	7, 9	**1,558,899**	1,443,982
Accretion on decommissioning liability		**14,162**	11,245
		2,450,915	2,125,762
Net income before tax		**218,482**	208,671
Tax expense (recovery)			
Current	19	**173**	(1,418)
Deferred	19	**73,433**	19,436
Net income		**144,876**	190,653
Other comprehensive income (loss)			
Items that may be subsequently reclassified to profit or loss			
Foreign currency translation of foreign operations		**93,920**	(9,144)
Comprehensive income		**238,796**	181,509
Net income per share	21		
Basic		**0.38**	0.58
Diluted		**0.37**	0.57

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(Cdn$000s)	Notes	Shareholders' capital	Contributed surplus	Deficit	Accumulated other comprehensive income (loss)	Total shareholders' equity
December 31, 2012		**11,249,168**	**102,755**	**(2,755,832)**	**(1,279)**	**8,594,812**
Issued pursuant to the DRIP [1]	13	**659,140**				**659,140**
Redemption of restricted shares	13	**82,395**	**(82,887)**	**70**		**(422)**
Share issue costs, net of tax		**(398)**				**(398)**
Share-based compensation	20		**89,749**			**89,749**
Forfeit of restricted shares	20		**(53)**			**(53)**
Net income				**144,876**		**144,876**
Dividends ($2.76 per share)				**(1,081,551)**		**(1,081,551)**
Foreign currency translation adjustment					**93,920**	**93,920**
December 31, 2013		**11,990,305**	**109,564**	**(3,692,437)**	**92,641**	**8,500,073**
December 31, 2011		7,706,268	126,034	(2,023,751)	7,865	5,816,416
Issued for cash		2,036,908				2,036,908
Issued on capital acquisitions		919,351				919,351
Issued pursuant to the DRIP [1]		564,086				564,086
Redemption of restricted shares		84,380	(91,395)	8,666		1,651
Share issue costs, net of tax		(61,825)				(61,825)
Share-based compensation			67,005			67,005
Forfeit of restricted shares			1,111			1,111
Net income				190,653		190,653
Dividends ($2.76 per share)				(931,400)		(931,400)
Foreign currency translation adjustment					(9,144)	(9,144)
December 31, 2012		11,249,168	102,755	(2,755,832)	(1,279)	8,594,812

(1) Premium Dividend™ and Dividend Reinvestment Plan

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the years ended December 31			
(Cdn$000s)	Notes	**2013**	2012
CASH PROVIDED BY (USED IN) OPERATING ACTIVITIES			
Net income		**144,876**	190,653
Items not affecting cash			
Other loss	17	**10,064**	60,455
Deferred tax expense		**73,433**	19,436
Share-based compensation	20	**67,752**	51,141
Depletion, depreciation, amortization and impairment		**1,558,899**	1,443,982
Accretion on decommissioning liability		**14,162**	11,245
Unrealized (gains) losses on derivatives	16, 22	**111,876**	(185,724)
Unrealized (gain) loss on foreign exchange	18	**60,994**	(5,774)
Decommissioning expenditures		**(11,375)**	(12,096)
Change in non-cash working capital	26	**(57,349)**	(29,375)
		1,973,332	1,543,943
INVESTING ACTIVITIES			
Development capital and other expenditures		**(1,746,873)**	(1,509,029)
Capital acquisitions, net	8	**(127,415)**	(1,855,721)
Other long-term assets		**(15,726)**	(3,323)
Investments		**-**	539
Change in non-cash working capital	26	**152,173**	76,743
		(1,737,841)	(3,290,791)
FINANCING ACTIVITIES			
Issue of shares, net of issue costs		**(1,033)**	1,946,186
Increase in long-term debt		**198,547**	148,868
Cash dividends		**(422,411)**	(367,314)
Change in non-cash working capital	26	**4,667**	19,936
		(220,230)	1,747,676
Impact of foreign currency on cash balances		**680**	(828)
INCREASE IN CASH		**15,941**	-
CASH AT BEGINNING OF YEAR		**-**	-
CASH AT END OF YEAR		**15,941**	-

See accompanying notes to the consolidated financial statements.

Supplementary Information:

Cash taxes recovered	**-**	1,646
Cash interest paid	**(77,028)**	(68,035)

December 31, 2013 and 2012

1. STRUCTURE OF THE BUSINESS

The principal undertakings of Crescent Point Energy Corp. (the “Company” or “Crescent Point”) are to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties and assets related thereto through a general partnership and wholly owned subsidiaries.

Crescent Point is the ultimate parent company and is amalgamated in Alberta, Canada under the Alberta Business Corporations Act. The address of the principal place of business is 2800, 111 - 5th Ave S.W., Calgary, Alberta, Canada, T2P 3Y6.

These annual consolidated financial statements were approved and authorized for issue by the Company's Board of Directors on March 11, 2014.

2. BASIS OF PREPARATION

a) Preparation

These consolidated financial statements are presented under International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”). The policies applied in these consolidated financial statements are based on IFRS issued and outstanding as of March 11, 2014, the date the Board of Directors approved the statements.

The Company’s presentation currency is Canadian dollars and all amounts reported are Canadian dollars unless noted otherwise. References to “US$” are to United States dollars. Crescent Point's operations are aggregated into one reportable segment based on the similarities between the Company's Canadian and U.S. operations.

b) Basis of measurement, functional and presentation currency

The Company’s presentation currency is Canadian dollars. The accounts of the Company’s foreign operations that have a functional currency different from the Company’s presentation currency are translated into the Company’s presentation currency at period end exchange rates for assets and liabilities and at the average rate over the period for revenues and expenses. Translation gains and losses relating to the foreign operations are recognized in Other Comprehensive Income (“OCI”) as cumulative translation adjustments.

c) Use of estimates and judgments

The preparation of consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses. Actual results may differ from these estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected. Significant estimates and judgments made by management in the preparation of consolidated financial statements are outlined below.

Oil and gas activities

Reserves estimates, although not reported as part of the Company’s consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on depletion, depreciation and amortization (“DD&A”), decommissioning liability, deferred taxes, asset impairments and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company’s oil and gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, property, plant and equipment (“PP&E”) is aggregated into cash-generating units (“CGUs”), based on separately identifiable and largely independent cash inflows. The determination of the Company’s CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability, based on the presence of reserves and which results in the transfer of assets from exploration and evaluation ("E&E") to PP&E, is subject to judgment.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates and forward foreign exchange rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax liabilities recognize the extent that temporary differences will be payable in future periods. The calculation of the liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flows and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently by the Company and its subsidiaries for all periods presented in these annual consolidated financial statements.

a) Principles of Consolidation

The consolidated financial statements include the accounts of the Company and its subsidiaries and any reference to the “Company” throughout these consolidated financial statements refers to the Company and its subsidiaries. All transactions between the Company and its subsidiaries have been eliminated.

The Company conducts many of its oil and gas production activities through jointly controlled operations and the financial statements reflect only the Company's proportionate interest in such activities. Joint control exists for contractual arrangements governing the Company's assets whereby the Company has less than 100 percent working interest, all of the partners have control of the arrangement collectively, and spending on the project requires unanimous consent of all parties that collectively control the arrangement and share the associated risks. The Company does not have any joint arrangements that are material to the Company or that are structured through joint venture arrangements.

b) Property, Plant and Equipment

Items of PP&E, which primarily consist of oil and gas development and production assets, are measured at cost less accumulated depletion, depreciation and any accumulated impairment losses. Development and production assets are accumulated into major area cost centres and represent the cost of developing the commercial reserves and initiating production.

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of PP&E are recognized as development and production assets only when they increase the future economic benefits embodied in the specific asset to which they relate. All other expenditures are recognized in net income as incurred. Capitalized development and production assets generally represent costs incurred in developing reserves and initiating or enhancing production from such reserves. The carrying amount of any replaced or sold component is derecognized.

Depletion and Depreciation

Development and production costs accumulated within major areas are depleted using the unit-of-production method based on estimated proved plus probable reserves before royalties, as determined by independent petroleum reservoir engineers. Natural gas reserves and production are converted to equivalent barrels of oil based upon the relative energy content (6:1). The depletion base includes capitalized costs, plus future costs to be incurred in developing proved plus probable reserves.

Corporate assets are depreciated over 5 years on a straight-line basis.

Impairment

The carrying amounts of PP&E are grouped into CGUs and reviewed quarterly for indicators of impairment. Indicators are events or changes in circumstances that indicate the carrying amount may not be recoverable. If indicators of impairment exist, the recoverable amount of the CGU is estimated. If the carrying amount of the CGU exceeds the recoverable amount, the CGU is written down with an impairment recognized in net income.

Assets are grouped into CGUs based on the integration between assets, shared infrastructures, the existence of common sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations. Estimates of future cash flows used in the calculation of the recoverable amount are based on reserve evaluation reports prepared by independent petroleum reservoir engineers. The recoverable amount is the higher of fair value less costs of disposal and the value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows. Discounted future net cash flows are based on forecasted commodity prices and costs over the expected economic life of the reserves and discounted using market-based rates to reflect a market participant's view of the risks associated with the assets. Value-in-use is assessed using the expected future cash flows discounted at a pre-tax rate.

Impairment losses recognized in prior periods, other than goodwill impairments, are assessed at each reporting date for any indicators that the impairment losses may no longer exist or may have decreased. In the event that an impairment loss reverses, the carrying amount of the asset is increased to the revised estimate of its recoverable amount, but only to the extent that the carrying amount does not exceed the amount that would have been determined, net of depletion, had no impairment loss been recognized on the asset in prior periods. The amount of the reversal is recognized in net earnings.

c) Exploration and Evaluation

Exploration and evaluation assets are comprised of the accumulated expenditures incurred in an area where technical feasibility and commercial viability has not yet been determined. Exploration and evaluation assets include undeveloped land and any drilling costs thereon.

Technical feasibility and commercial viability are considered to be determinable when reserves are discovered. Upon determination of reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified from E&E assets to PP&E.

Costs incurred prior to acquiring the legal rights to explore an area are expensed as incurred.

Amortization

Undeveloped land classified as E&E is amortized by major area over the average primary lease term and recognized in net income. Drilling costs classified as E&E assets are not amortized but are subject to impairment.

Impairment

Exploration and evaluation assets are reviewed quarterly for indicators of impairment and upon reclassification from E&E to PP&E. Exploration and evaluation assets are tested for impairment at the operating segment level by combining E&E assets with PP&E. The recoverable amount is the greater of fair value less costs of disposal or value-in-use. Fair value less costs of disposal is derived by estimating the discounted after-tax future net cash flows as described in the PP&E impairment test, plus the fair market value of undeveloped land and seismic. Value-in-use is assessed using the present value of the expected future cash flows discounted at a pre-tax rate.

Impairments of E&E assets are reversed when there has been a subsequent increase in the recoverable amount, but only to the extent of what the carrying amount would have been had no impairment been recognized.

d) Decommissioning Liability

The Company recognizes the present value of a decommissioning liability in the period in which it is incurred. The obligation is recorded as a liability on a discounted basis using the relevant risk free rate, with a corresponding increase to the carrying amount of the related asset. Over time, the liabilities are accreted for the change in their present value and the capitalized costs are depleted on a unit-of-production basis over the life of the underlying proved plus probable reserves. Accretion expense is recognized in net income. Revisions to the discount rate, estimated timing or amount of future cash flows would also result in an increase or decrease to the decommissioning liability and related asset.

e) Reclamation Fund

The Company established a reclamation fund to fund future decommissioning costs and environmental emissions reduction costs. Effective January 1, 2013, the Board of Directors approved contributions of $0.70 per barrel of oil equivalent ("boe") of production; prior to this, 2012 contributions were $0.50 per boe. Additional contributions can be made at the discretion of management.

f) Goodwill

The Company records goodwill relating to business combinations when the purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired business. The goodwill balance is assessed for impairment annually or as events occur that could result in impairment. Goodwill is tested for impairment at an operating segment level by combining the carrying amounts of PP&E, E&E assets and goodwill and comparing this to the recoverable amount. The recoverable amount is the greater of fair value less costs of disposal or value-in-use. Fair value less costs of disposal is derived by estimating the discounted

after-tax future net cash flows as described in the PP&E impairment test, plus the fair market value of undeveloped land and seismic. Value-in-use is assessed using the present value of the expected future cash flows discounted at a pre-tax rate. Any excess of the carrying amount over the recoverable amount is the impairment amount. Impairment charges, which are not tax affected, are recognized in net income. Goodwill is reported at cost less any accumulated impairment. Goodwill impairments are not reversed.

g) Share-based Compensation

Restricted shares granted under the Restricted Share Bonus Plan are accounted for at fair value. Share-based compensation expense is determined based on the estimated fair value of shares on the date of grant. Forfeitures are estimated at the grant date and are subsequently adjusted to reflect actual forfeitures. The expense is recognized over the service period, with a corresponding increase to contributed surplus. The Company capitalizes the portion of share-based compensation directly attributable to development activities, with a corresponding decrease to share-based compensation expense. At the time the restricted shares vest, the issuance of shares is recorded as an increase to shareholders' capital and a corresponding decrease to contributed surplus.

Deferred share units ("DSUs") are accounted for at fair value. Share-based compensation expense is determined based on the estimated fair value of the DSUs on the date of the grant and subsequently adjusted to reflect the fair value at each period end. Fair value is based on the prevailing Crescent Point share price.

h) Income Taxes

The Company follows the liability method of accounting for income taxes. Under this method, deferred income taxes are recognized for the estimated effect of any differences between the accounting and tax basis of assets and liabilities, using enacted or substantively enacted income tax rates expected to apply when the deferred tax asset or liability is settled. The effect of a change in income tax rates on deferred income taxes is recognized in net income in the period in which the change occurs.

The tax expense for the period comprises current and deferred tax. Tax is recognized in the income statement, except to the extent that it relates to items recognized in other comprehensive income or directly in equity. In this case, the tax is also recognized in other comprehensive income or directly in equity, respectively.

The Company is able to deduct certain settlements under its Restricted Share Bonus Plan. To the extent the tax deduction exceeds the cumulative remuneration cost for a particular restricted share grant recorded in net income, the tax benefit related to the excess is recorded directly within equity.

Deferred income tax assets and liabilities are presented as non-current.

i) Financial Instruments

The Company has early adopted IFRS 9,*Financial Instruments* ("IFRS 9"), with a date of initial application of January 1, 2010. This new standard replaces the current multiple classification and measurement model for non-equity financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value. Classification depends on the entity's business model for managing financial instruments and the contractual cash flow characteristics of the financial instrument.

In addition, the fair value option for financial liabilities was amended. The changes in fair value attributable to a liability's credit risk will be recorded in other comprehensive income rather than through net income, unless this presentation creates an accounting mismatch. Changes in fair value attributable to a financial liability's credit risk are not subsequently reclassified to net income.

For investments in equity instruments which are not subject to control, joint control, or significant influence, on initial recognition IFRS 9 allows an entity to irrevocably elect classification at "fair value through profit or loss" or "fair value through other comprehensive income".

The Company uses financial derivative instruments and physical delivery commodity contracts from time to time to reduce its exposure to fluctuations in commodity prices, foreign exchange rates and interest rates. The Company also makes investments in companies from time to time in connection with the Company's acquisition and divestiture activities.

Financial derivative instruments

Financial derivative instruments are included in current assets/liabilities except for those with maturities greater than 12 months after the end of the reporting period, which are classified as non-current assets/liabilities.

The Company has not designated any of its financial derivative contracts as effective accounting hedges and, accordingly, fair values its financial derivative contracts with the resulting gains and losses recorded in net income.

The fair value of a financial derivative instrument on initial recognition is normally the transaction price. Subsequent to initial recognition, the fair values are based on quoted market prices where available from active markets, otherwise fair values are estimated based on market prices at the reporting date for similar assets or liabilities with similar terms and conditions, or by discounting future payments of interest and principal at estimated interest rates that would be available to the Company at the reporting date.

Financial assets and liabilities

Financial assets and liabilities are measured at fair value on initial recognition. For non-equity instruments, measurement in subsequent periods depends on the classification of the financial asset or liability as “fair value through profit or loss” or “amortized cost”.

Financial assets and liabilities classified as fair value through profit or loss are subsequently carried at fair value, with changes recognized in net income.

Financial assets and liabilities classified as amortized cost are subsequently carried at amortized cost using the effective interest rate method.

Currently, the Company classifies all non-equity financial instruments which are not financial derivative instruments as amortized cost.

At each reporting date, the Company assesses whether there is objective evidence that a financial asset carried at amortized cost is impaired. If such evidence exists, the Company recognizes an impairment loss in net income. Impairment losses are reversed in subsequent periods if the impairment loss decrease can be related objectively to an event occurring after the impairment was recognized.

For investments in equity instruments, the subsequent measurement is dependent on the Company’s election to classify such instruments as fair value through profit or loss or fair value through other comprehensive income. Currently, the Company classifies all investments in equity instruments as fair value through profit or loss, whereby the Company recognizes movements in the fair value of the investment (adjusted for dividends) in net income. If the fair value through other comprehensive income classification is selected, the Company would recognize any dividends from the investment in net income and would recognize fair value re-measurements of the investment in other comprehensive income. Regardless of the classification, such investments are not subject to impairment testing.

j) Business Combinations

Business combinations are accounted for using the acquisition method. Identifiable assets acquired and liabilities and contingent liabilities assumed in a business combination are measured at their fair values at the acquisition date. The cost of an acquisition is measured as the fair value of the assets given, equity instruments issued and liabilities incurred or assumed at the acquisition date. The excess of the cost of the acquisition over the fair value of the identifiable assets, liabilities and contingent liabilities acquired is recorded as goodwill. If the cost of the acquisition is less than the fair value of the net assets acquired, the difference is recognized immediately in net income. Transaction costs associated with business combinations are expensed as incurred.

k) Foreign Currency Translation

Foreign operations

The Company has operations in the United States (“U.S.”) transacted via U.S. subsidiaries. The assets and liabilities of foreign operations are restated to Canadian dollars at exchange rates in effect at the balance sheet date. The income and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. The resulting unrealized gain or loss is included in other comprehensive income.

Foreign transactions

Transactions in foreign currencies not incurred by the Company’s U.S. subsidiaries are translated to Canadian dollars at exchange rates in effect at the transaction dates. Foreign currency assets and liabilities are restated to Canadian dollars at exchange rates in effect at the balance sheet date and income and expenses are restated to Canadian dollars using the average exchange rate for the period. Both realized and unrealized gains and losses resulting from the settlement or restatement of foreign currency transactions are included in net income.

l) Revenue Recognition

Oil and gas revenue includes the sale of crude oil, natural gas and natural gas liquids and is recognized when the risks and rewards of ownership have been substantially transferred.

m) Cash and Cash Equivalents

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

n) Leases

Leases in which substantially all of the risks and rewards of ownership are retained by the lessor are classified as operating leases. Operating lease payments are recognized as an expense on a straight-line basis over the lease term.

Leases where the Company assumes substantially all the risks and rewards of ownership are classified as finance leases within property, plant and equipment.

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

o) Earnings Per Share

Basic earnings per share ("EPS") is calculated by dividing the net income for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period.

Diluted EPS is calculated by adjusting the weighted average number of common shares outstanding for dilutive instruments. The number of shares included with respect to dilutive instruments, being restricted shares issued under the Company's Restricted Share Bonus Plan, is computed using the treasury stock method. The treasury stock method assumes that the deemed proceeds related to unrecognized share-based compensation are used to repurchase shares at the average market price during the period.

4. CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2013, the Company adopted the following IFRS:

- IFRS 7 *Financial Instruments: Disclosures* - IFRS 7 was amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar agreements. The additional disclosures can be found in Note 22. The application of the amendment had no impact on the consolidated statements of comprehensive income or the consolidated balance sheets.
- IFRS 9 *Financial Instruments* - IFRS 9 was amended to present a new hedge accounting model. The Company does not currently apply hedge accounting and determined that the amendment to IFRS 9 had no impact on the consolidated statements of comprehensive income or the consolidated balance sheet.
- IFRS 10 *Consolidated Financial Statements* - IFRS 10 provides guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The Company reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change to the consolidation status of its subsidiaries.
- IFRS 11 *Joint Arrangements* - IFRS 11 presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The Company reviewed its joint arrangements and determined that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements. The Company's share of the assets, liabilities, revenues and expenses are recognized in the annual consolidated financial statements.
- IFRS 12 *Disclosure of Interests in Other Entities*- IFRS 12 aggregates and amends disclosure requirements included within other standards. The standard requires an entity to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The application of IFRS 12 had no impact on the consolidated statements of comprehensive income or the consolidated balance sheets.
- IFRS 13 *Fair Value Measurement* - IFRS 13 provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Company adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013.

Effective January 1, 2014, the Company will adopt the following IFRS:

- IAS 36 *Impairment of Assets* - IAS 36 was amended in May 2013 to reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments require retrospective application and will be adopted by the Company on January 1, 2014. The adoption will only impact Crescent Point's disclosures in the notes to the financial statements in periods when an impairment loss or impairment recovery is recognized.

5. LONG-TERM INVESTMENTS

($000s)	2013	2012
Investments in public companies, beginning of year	**28,314**	101,657
Acquisitions and dispositions, net	**-**	(2,539)
Unrealized loss recognized in other loss	**(4,055)**	(70,804)
Investments in public companies, end of year	**24,259**	28,314
Investments in private companies, beginning of year	**56,592**	50,260
Acquisitions and dispositions, net	**-**	25,000
Unrealized loss recognized in other loss	**(6,622)**	(18,668)
Investments in private companies, end of year	**49,970**	56,592
Long-term investments, end of year	**74,229**	84,906

a) Public Companies

The Company holds common shares and common share purchase warrants in publicly traded oil and gas companies. The investments are classified as financial assets at fair value through profit or loss and are fair valued with the resulting gain or loss recorded in net income. At December 31, 2013, the investments are recorded at a fair value of $24.3 million which is $79.7 million less than the original cost of the investments. At December 31, 2012, the investments were recorded at a fair value of $28.3 million which was $75.6 million less than the original cost of the investments.

b) Private Companies

The Company holds common shares in private oil and gas companies. The investments are classified as financial assets at fair value through profit or loss and are fair valued with the resulting gain or loss recorded in net income. At December 31, 2013, the investments are recorded at a fair value of $50.0 million which is $17.0 million less than the original cost of the investments. At December 31, 2012, the investments were recorded at a fair value of $56.6 million which was $10.4 million less than the original cost of the investments.

6. OTHER LONG-TERM ASSETS

($000s)	2013	2012
Reclamation fund	**26,181**	10,455
Other receivables	**11,777**	11,777
Other long-term assets	**37,958**	22,232

a) Reclamation fund

The following table reconciles the reclamation fund:

($000s)	2013	2012
Balance, beginning of year	**10,455**	7,816
Contributions	**30,734**	18,079
Expenditures	**(15,008)**	(15,440)
Balance, end of year	**26,181**	10,455

b) Other receivables

At December 31, 2013, the Company had investment tax credits of $11.8 million (December 31, 2012 - $11.8 million).

7. EXPLORATION AND EVALUATION ASSETS

($000s)	**2013**	2012
Exploration and evaluation assets at cost	**1,590,298**	1,700,442
Accumulated amortization	**(901,974)**	(619,685)
Net carrying amount	**688,324**	1,080,757
Reconciliation of movements during the year		
Cost, beginning of year	**1,700,442**	1,242,573
Accumulated amortization, beginning of year	**(619,685)**	(376,210)
Net carrying amount, beginning of year	**1,080,757**	866,363
Net carrying amount, beginning of year	**1,080,757**	866,363
Acquisitions through business combinations, net	**6,600**	414,255
Additions	**471,900**	583,791
Dispositions	**(1,993)**	(1,239)
Transfers to property, plant and equipment	**(614,446)**	(530,835)
Amortization	**(275,504)**	(247,883)
Foreign exchange	**21,010**	(3,695)
Net carrying amount, end of year	**688,324**	1,080,757

E&E assets consist of the Company's undeveloped land and exploration projects which are pending the determination of technical feasibility. Additions represent the Company's share of the cost of E&E assets. At December 31, 2013, $688.3 million remains in E&E assets after $614.4 million was transferred to PP&E following the determination of technical feasibility during the year ended December 31, 2013 (year ended December 31, 2012 **-** $1.1 billion and $530.8 million, respectively).

Impairment test of exploration and evaluation assets

There were no indicators of impairment at December 31, 2013 or December 31, 2012.

8. CAPITAL ACQUISITIONS AND DISPOSITIONS

In the year ended December 31, 2013, the Company incurred $5.8 million (December 31, 2012 - $16.4 million) of transaction costs related to business combinations that are recorded as general and administrative expenses.

Minor Property Acquisitions and Dispositions

Crescent Point completed minor property acquisitions and dispositions during the year ended December 31, 2013 for net consideration of $118.3 million ($121.8 million was allocated to PP&E and E&E assets). These minor property acquisitions and dispositions were completed with full tax pools.

9. PROPERTY, PLANT AND EQUIPMENT

($000s)	2013	2012
Development and production assets	**14,964,220**	12,740,337
Corporate assets	**26,176**	22,843
Property, plant and equipment at cost	**14,990,396**	12,763,180
Accumulated depletion, depreciation and impairment	**(3,731,249)**	(2,443,312)
Net carrying amount	**11,259,147**	10,319,868
Reconciliation of movements during the year		
Development and production assets		
Cost, beginning of year	**12,740,337**	8,409,567
Accumulated depletion and impairment, beginning of year	**(2,431,102)**	(1,244,709)
Net carrying amount, beginning of year	**10,309,235**	7,164,858
Net carrying amount, beginning of year	**10,309,235**	7,164,858
Acquisitions through business combinations, net	**119,611**	2,838,778
Additions	**1,414,067**	1,008,973
Dispositions	**(2,454)**	(36,243)
Transfers from exploration and evaluation assets	**614,446**	530,835
Depletion	**(1,181,383)**	(1,004,321)
Impairment	**(98,291)**	(189,074)
Foreign exchange	**73,678**	(4,571)
Net carrying amount, end of year	**11,248,909**	10,309,235
Cost, end of year	**14,964,220**	12,740,337
Accumulated depletion and impairment, end of year	**(3,715,311)**	(2,431,102)
Net carrying amount, end of year	**11,248,909**	10,309,235
Corporate assets		
Cost, beginning of year	**22,843**	17,109
Accumulated depreciation, beginning of year	**(12,210)**	(9,506)
Net carrying amount, beginning of year	**10,633**	7,603
Net carrying amount, beginning of year	**10,633**	7,603
Additions	**3,285**	5,740
Depreciation	**(3,721)**	(2,704)
Foreign exchange	**41**	(6)
Net carrying amount, end of year	**10,238**	10,633
Cost, end of year	**26,176**	22,843
Accumulated depreciation, end of year	**(15,938)**	(12,210)
Net carrying amount, end of year	**10,238**	10,633

At December 31, 2013, future development costs of $5.9 billion (December 31, 2012 - $5.7 billion) are included in costs subject to depletion.

Direct general and administrative costs capitalized by the Company during the year ended December 31, 2013 were $42.2 million (year ended December 31, 2012 - $32.0 million), including $23.1 million of share-based compensation costs (year ended December 31, 2012 - $17.7 million).

Impairment test of property, plant and equipment

For the purposes of determining whether impairment of assets has occurred, and the extent of any impairment or its reversal, management exercises their judgment in estimating future cash flows for the recoverable amount, being the higher of fair value less costs of disposal and value in use. These key judgments include estimates about recoverable reserves (see Use of estimates and judgments discussion in Note 2c), forecast benchmark commodity prices, royalties, operating costs and discount rates.

Forecast benchmark commodity price assumptions tend to be stable because short-term increases or decreases in prices are not considered indicative of long-term price levels, but are nonetheless subject to change.

The following table outlines the forecast benchmark commodity prices and the exchange rate used in the impairment calculation of property, plant and equipment at December 31, 2013. The Company used an average after-tax discount rate of 10 percent.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023** [2]
WTI ($US/bbl)	97.50	97.50	97.50	97.50	97.50	97.50	98.54	100.51	102.52	104.57
Exchange Rate ($US/$Cdn)	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
WTI ($Cdn/bbl)	102.63	102.63	102.63	102.63	102.63	102.63	103.73	105.80	107.92	110.07
AECO ($Cdn/MMbtu)	4.03	4.26	4.50	4.74	4.97	5.21	5.33	5.44	5.55	5.66

(1) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, distance to market and other factors in performing our impairment tests.

(2) Forecast benchmark commodity prices are assumed to increase by 2% in each year after 2023 to the end of the reserve life. Exchange rates are assumed to be constant at 0.95.

At December 31, 2013, the Company determined that the carrying amount of the Southern Alberta CGU exceeded its fair value less costs of disposal. The full amount of the impairment was attributed to PP&E and, as a result, an impairment loss of $98.3 million was recorded as a component of depletion, depreciation, amortization and impairment expense. The Southern Alberta CGU is comprised primarily of properties in the early stages of development for which the operating results are included in the Canadian operating segment. The impairment in 2013 was largely a result of the exploratory nature of the Alberta Bakken resource play which resulted in negative technical revisions to proved plus probable reserves and an increase in expected operating and abandonment costs. Changes in any of the key judgments, such as a downward revision in reserves, a decrease in forecast benchmark commodity prices, an increase in royalties, or an increase in operating costs would decrease the recoverable amounts of assets and any impairment charges would affect net income. For the year ended December 31, 2013, a one percent increase in the assumed discount rate would result in an additional impairment for the Southern Alberta CGU of approximately $54.3 million, while a five percent decrease in the forward commodity price estimate would result in an additional impairment of approximately $95.5 million.

The Company reported an impairment loss of $189.1 million for the year ended December 31, 2012 related to the Southern Alberta CGU largely as a result of the decrease in forecast benchmark commodity prices at December 31, 2012 compared to December 31, 2011, the early development stage of the properties and associated higher initial capital expenditures.

10. GOODWILL

($000s)	**2013**	2012
Goodwill, beginning of year	**251,919**	207,672
Wild Stream Exploration Inc. acquisition	**-**	24,022
Reliable Energy Ltd. acquisition	**-**	20,225
Goodwill, end of year	**251,919**	251,919

Goodwill has been assigned to the Canadian operating segment.

Impairment test of goodwill

The impairment test of goodwill at December 31, 2013 and 2012 concluded that the estimated recoverable amount exceeded the carrying amount. As such, no goodwill impairment existed. The recoverable amount of the Canadian operating segment was estimated to be $14.2 billion at December 31, 2013 and was determined based on fair value less costs of disposal. The fair value measurement of the recoverable amount of the Canadian operating segment is categorized as Level 3 according to the IFRS 13 fair value hierarchy. Refer to Note 9 - “Property, Plant and Equipment” for a description of the key input estimates and the methodology used in the determination of the estimated recoverable amount related to goodwill.

11. LONG-TERM DEBT

The following table reconciles long-term debt:

($000s)	**2013**	2012
Bank credit facilities	**546,595**	653,123
Senior guaranteed notes	**1,187,519**	821,466
Long-term debt	**1,734,114**	1,474,589

a) Bank Credit Facilities

The Company has a syndicated unsecured credit facility with fourteen banks and an operating credit facility with one Canadian chartered bank, for a total amount available under the combined facilities of $2.1 billion. The syndicated unsecured credit facility also includes an accordion feature that allows the Company to increase the facility by up to $500.0 million.

The credit facilities bear interest at the Canadian prime rate plus a margin based on a sliding scale ratio of the Company's senior debt to EBITDA, adjusted for certain non-cash items. The syndicated unsecured credit facility constitutes a revolving credit facility for a three year term which is extendible annually; the current maturity date is June 10, 2016. The operating credit facility constitutes a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period, subject to a one year term out period should the lender not agree to an annual extension; the current conversion date is June 6, 2014. The combined credit facilities have covenants which restrict the Company's ratio of senior debt to EBITDA, adjusted for certain non-cash items, to a maximum of 3.0:1.0 and the ratio of debt to capital, adjusted for certain non-cash items, to a maximum of 0.5:1.0. The Company is in compliance with all debt covenants at December 31, 2013.

The Company has letters of credit in the amount of $3.9 million outstanding at December 31, 2013.

The Company manages its credit facilities through a combination of bankers' acceptance loans and interest rate swaps.

b) Senior Guaranteed Notes

The Company has closed private offerings of senior guaranteed notes raising total gross proceeds of US$983.0 million and Cdn$142.0 million. The notes are unsecured and rank *pari passu* with the Company's bank credit facilities and carry a bullet repayment on maturity. The senior guaranteed notes have financial covenants similar to those of the combined credit facilities described above. The terms, rates and carrying amounts of the Company's outstanding senior guaranteed notes are detailed below:

Principal ($000s)	Maturity Date	Coupon Rate	Interest Payment Dates	**2013**	2012
Cdn$50,000	March 24, 2015	4.92%	September 24 and March 24	**50,000**	50,000
US$37,500	March 24, 2015	4.71%	September 24 and March 24	**39,885**	37,309
US$52,000	April 14, 2016	3.93%	October 14 and April 14	**55,307**	51,735
US$67,500	March 24, 2017	5.48%	September 24 and March 24	**71,793**	67,156
US$31,000	April 14, 2018	4.58%	October 14 and April 14	**32,972**	30,842
US$20,000	June 12, 2018	2.65%	December 12 and June 12	**21,272**	-
Cdn$7,000	May 22, 2019	4.29%	November 22 and May 22	**7,000**	7,000
US$68,000	May 22, 2019	3.39%	November 22 and May 22	**72,325**	67,653
US$155,000	March 24, 2020	6.03%	September 24 and March 24	**164,858**	154,209
Cdn$50,000	April 14, 2021	5.53%	October 14 and April 14	**50,000**	50,000
US$82,000	April 14, 2021	5.13%	October 14 and April 14	**87,215**	81,582
Cdn$25,000	May 22, 2022	4.76%	November 22 and May 22	**25,000**	25,000
US$200,000	May 22, 2022	4.00%	November 22 and May 22	**212,720**	198,980
Cdn$10,000	June 12, 2023	4.11%	December 12 and June 12	**10,000**	-
US$270,000	June 12, 2023	3.78%	December 12 and June 12	**287,172**	-
Senior guaranteed notes				**1,187,519**	821,466

Concurrent with the issuance of US$953.0 million senior guaranteed notes, the Company entered into cross currency interest rate swaps ("CCIRS") with a syndicate of financial institutions. To manage the Company's foreign exchange risk, the CCIRS fix the US dollar amount of the notes for purposes of interest and principal repayments at a notional amount of $953.2 million. Concurrent with the issuance of US$30.0 million senior guaranteed notes, the Company entered a cross currency principal swap which fixed the principal repayment at a notional amount of $32.2 million. See additional information in Note 22 - “Financial Instruments and Derivatives”.

12. DECOMMISSIONING LIABILITY

The following table reconciles the decommissioning liability:

($000s)	2013	2012
Decommissioning liability, beginning of year	**502,432**	379,616
Liabilities incurred	**32,562**	18,919
Liabilities acquired through capital acquisitions	**4,291**	66,684
Liabilities disposed through capital dispositions	**(793)**	(9,497)
Liabilities settled	**(11,375)**	(12,096)
Revaluation of acquired decommissioning liabilities (1)	**3,256**	57,251
Change in estimated future costs	**115,266**	(9,690)
Change in discount rate	**(30,263)**	-
Accretion expense	**14,162**	11,245
Decommissioning liability, end of year	**629,538**	502,432
Expected to be incurred in one year	**18,469**	-
Expected to be incurred beyond one year	**611,069**	502,432

(1) These amounts relate to the revaluation of acquired decommissioning liabilities at the end of the period using a risk-free discount rate. At the date of acquisition, acquired decommissioning liabilities are fair valued.

The total future decommissioning liability was estimated by management based on the Company's net ownership in all wells and facilities. This includes all estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods. The Company has estimated the net present value of its total decommissioning liability to be $629.5 million at December 31, 2013 (December 31, 2012 - $502.4 million) based on total estimated undiscounted cash flows to settle the obligation of $739.8 million (December 31, 2012 - $531.6 million). These obligations are expected to be settled through 2047, with the majority expected after 2028. The estimated cash flows have been discounted using an average risk free rate of approximately 3 percent and an inflation rate of 2 percent (December 31, 2012 - approximately 2.5 percent and 2 percent, respectively).

13. SHAREHOLDERS' CAPITAL

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

	2013		2012	
	Number of shares	**Amount ($000s)**	Number of shares	Amount ($000s)
Common shares, beginning of year	**374,702,264**	**11,439,861**	288,025,465	7,835,136
Issued for cash	**-**	**-**	48,784,500	2,036,908
Issued on capital acquisitions	**-**	**-**	21,311,081	919,351
Issued on redemption of restricted shares (1)	**2,045,169**	**82,395**	2,150,033	84,380
Issued pursuant to the dividend reinvestment plans	**18,246,133**	**659,140**	14,431,185	564,086
Common shares, end of year	**394,993,566**	**12,181,396**	374,702,264	11,439,861
Cumulative share issue costs, net of tax	**-**	**(191,091)**	-	(190,693)
Total shareholders' capital, end of year	**394,993,566**	**11,990,305**	374,702,264	11,249,168

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

At December 31, 2013, the Company recorded dividends payable of $90.8 million which was settled with cash of $65.0 million and Crescent Point common shares issued pursuant to the DRIP valued at $25.8 million (678,361 common shares) on January 15, 2014. At December 31, 2012, the Company recorded dividends payable of $86.2 million which was settled with cash of $27.9 million and Crescent Point common shares issued pursuant to the DRIP valued at $58.3 million (1,638,734 common shares) on January 15, 2013. In preceding years (December 31, 2012 - $58.3 million), the component of the dividend payable to be settled with Crescent Point common shares pursuant to the DRIP was recorded as shareholders' capital at the balance sheet date.

14. DEFICIT

($000s)	2013	2012
Accumulated earnings	**1,054,349**	909,473
Accumulated tax effect on redemption of restricted shares	**8,736**	8,666
Accumulated dividends	**(4,755,522)**	(3,673,971)
Deficit	**(3,692,437)**	(2,755,832)

15. CAPITAL MANAGEMENT

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

($000s)	**2013**	2012
Long-term debt	**1,734,114**	1,474,589
Working capital deficiency [1]	**406,134**	287,911
Unrealized foreign exchange on translation of US dollar senior guaranteed notes	**(63,170)**	(2,176)
Net debt	**2,077,078**	1,760,324
Shareholders' equity	**8,500,073**	8,594,812
Total capitalization	**10,577,151**	10,355,136

(1) Working capital deficiency is calculated as accounts payable and accrued liabilities plus dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the equity settled component of dividends payable.

Crescent Point's objective for managing capital is to maintain a strong balance sheet and capital base to provide financial flexibility, stability to dividends and to position the Company for future development of the business. Ultimately, Crescent Point strives to maximize long-term stakeholder value by ensuring the Company has the financing capacity to fund projects that are expected to add value to stakeholders and distribute any excess cash that is not required for financing projects.

Crescent Point manages and monitors its capital structure and short-term financing requirements using a non-GAAP measure, the ratio of net debt to funds flow from operations. Net debt is calculated as long-term debt plus accounts payable and accrued liabilities and dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the equity settled component of dividends payable and unrealized foreign exchange on translation of US dollar senior guaranteed notes. Funds flow from operations is calculated as cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Crescent Point's objective is to maintain a net debt to funds flow from operations ratio of approximately 1.0 times. This metric is used to measure the Company's overall debt position and measure the strength of the Company's balance sheet. Crescent Point monitors this ratio and uses this as a key measure in making decisions regarding financing, capital spending and dividend levels. The Company's net debt to funds flow from operations ratio at December 31, 2013 was 1.0 times (December 31, 2012 - 1.1 times). The funds flow from operations only reflects funds flow from operations generated on acquired properties since the closing date of the acquisitions.

Crescent Point strives to provide stability to its dividends over time by managing risks associated with the oil and gas industry. To accomplish this, the Company maintains a conservative balance sheet with significant unutilized lines of credit, manages its exposure to fluctuating interest rates and foreign exchange rates on its long-term debt, and actively hedges commodity prices using a 3½ year risk management program by hedging up to 65 percent, unless otherwise approved by the Board of Directors, of after royalty volumes using a portfolio of swaps, collars and put option instruments and up to 35 percent of after royalty volumes using a combination of financial derivatives and fixed differential physical contracts to manage price differentials.

Crescent Point is subject to certain financial covenants on its credit facility and senior guaranteed notes agreements and is in compliance with all financial covenants as at December 31, 2013.

16. DERIVATIVE GAINS (LOSSES)

($000s)	**2013**	2012
Realized losses	**(90,871)**	(17,604)
Unrealized gains (losses)	**(111,876)**	185,724
Derivative gains (losses)	**(202,747)**	168,120

17. OTHER LOSS

($000s)	**2013**	2012
Unrealized loss on long-term investments	**(10,677)**	(89,472)
Gain on the sale of marketable securities	**-**	2
Gain on sale of long-term investments	**-**	470
Gain on disposition of assets	**-**	28,545
Other gain	**613**	-
Other loss	**(10,064)**	(60,455)

18. FOREIGN EXCHANGE GAIN (LOSS)

($000s)	**2013**	2012
Realized		
Foreign exchange loss on cross currency interest rate swaps	**(4,308)**	(3,838)
Other foreign exchange gain	**1,134**	495
Unrealized		
Foreign exchange gain (loss) on translation of US dollar senior guaranteed notes	**(60,994)**	5,774
Other foreign exchange gain (loss)	**(337)**	361
Foreign exchange gain (loss)	**(64,505)**	2,792

19. INCOME TAXES

The provision for income taxes is as follows:

($000s)	**2013**	2012
Current tax:		
Canada	**137**	(1,418)
Luxembourg	**36**	-
Current expense (recovery)	**173**	(1,418)
Deferred tax:		
Canada	**76,801**	33,980
United States	**(3,368)**	(14,544)
Deferred expense	**73,433**	19,436
Income tax expense	**73,606**	18,018

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

($000s)	**2013**	2012
Income before income taxes	**218,482**	208,671
Statutory income tax rate	**26.04%**	26.14%
Expected provision for income taxes	**56,893**	54,547
Effect of change in corporate tax rates	**(3,101)**	-
Effect of tax rates in foreign jurisdictions	**(9,009)**	(5,779)
Effect of restricted share bonus plan	**(3,373)**	(38,695)
Effect of change in deferred tax asset	**20,530**	-
Effect of non-taxable capital losses	**8,617**	10,874
Other	**3,049**	(2,929)
Income tax expense	**73,606**	18,018

The statutory combined federal and provincial income tax rate decreased from 26.14% in 2012 to 26.04% in 2013 due to a change in the allocation of taxable income between provinces.

The deferred income tax liabilities are expected to be settled in the following periods:

($000s)	**2013**	2012
Deferred income tax:		
To be settled within 12 months	**31,121**	(1,074)
To be settled after more than 12 months	**(895,729)**	(791,591)
Deferred income tax	**(864,608)**	(792,665)

The movement in deferred income tax liabilities and assets is as follows:

($000s)	At January 1, 2013	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	**At December 31, 2013**
Deferred income tax assets:				
Decommissioning liability	134,144	-	32,870	**167,014**
Income tax losses carried forward	184,974	-	(62,394)	**122,580**
Share issue costs	33,195	141	(10,924)	**22,412**
Risk management contracts	6,230	-	26,381	**32,611**
Other	11,308	1,349	(10,611)	**2,046**
	369,851	1,490	(24,678)	**346,663**
Deferred income tax liabilities:				
Property, plant & equipment	(966,007)	-	(94,514)	**(1,060,521)**
Timing of partnership items	(180,381)	-	42,970	**(137,411)**
Risk management contracts	(16,128)	-	2,789	**(13,339)**
	(1,162,516)	-	(48,755)	**(1,211,271)**
Net deferred income tax liabilities	(792,665)	1,490	(73,433)	**(864,608)**

($000s)	At January 1, 2012	(Charges) / credits due to acquisitions & other	(Charged) / credited to earnings	At December 31, 2012
Deferred income tax assets:				
Decommissioning liability	99,601	9,434	25,109	134,144
Income tax losses carried forward	163,522	22,557	(1,105)	184,974
Share issue costs	21,263	25,310	(13,378)	33,195
Risk management contracts	43,449	1,346	(38,565)	6,230
Other	284	8,689	2,335	11,308
	328,119	67,336	(25,604)	369,851
Deferred income tax liabilities:				
Property, plant & equipment	(760,265)	(186,306)	(19,436)	(966,007)
Timing of partnership items	(215,466)	-	35,085	(180,381)
Risk management contracts	(4,921)	(1,224)	(9,983)	(16,128)
Other	-	(502)	502	-
	(980,652)	(188,032)	6,168	(1,162,516)
Net deferred income tax liabilities	(652,533)	(120,696)	(19,436)	(792,665)

The approximate amounts of tax pools available as at December 31, 2013 and 2012 are as follows:

($000s)	**2013**	2012
Tax pools:		
Canada	**6,751,472**	7,131,035
United States	**1,626,298**	1,365,756
Total	**8,377,770**	8,496,791

The tax pools presented do not include the impact of income from the general partnership for its fiscal period ended December 31, 2013 for which the Company is entitled to claim a reserve for current income tax purposes. Including the impact of income from the general partnership which is taxable to the Company in future years, the net tax pools remaining at December 31, 2013 are approximately $7.9 billion (December 31, 2012 - $7.8 billion).

The above tax pools include estimated Canadian non-capital losses carried forward of $387.2 million (December 31, 2012 - $683.1 million) that expire in the years 2029 through 2031, and U.S. net operating losses of $72.5 million (December 31, 2012 - $30.2 million) which expire in the years 2024 through 2032. A deferred income tax asset has not been recognized for U.S. net operating losses of $15.3 million (December 31, 2012 - $14.3 million) as there is not sufficient certainty regarding future utilization.

A deferred tax asset has not been recognized in respect of certain unrealized capital losses and capital losses carried forward for Canadian tax purposes in the amount of $20.5 million (December 31, 2012 - nil). Recognition is dependent on the realization of future taxable capital gains.

A deferred tax asset has not been recognized in respect of temporary differences associated with investments in subsidiaries as it is not likely that the temporary differences will reverse in the foreseeable future. The deductible temporary differences associated with investments in subsidiaries is approximately $52.8 million (December 31, 2012 - $44.7 million).

20. SHARE-BASED COMPENSATION

Restricted Share Bonus Plan

The Company has a Restricted Share Bonus Plan pursuant to which the Company may grant restricted shares to directors, officers, employees and consultants. The restricted shares vest on terms up to three years from the grant date as determined by the Board of Directors.

Restricted shareholders are eligible for monthly dividends on their restricted shares, immediately upon grant.

Deferred Share Unit Plan

The Company has a DSU plan for directors. Each DSU vests on the date of the grant, however the settlement of the DSU occurs following a change of control or when the individual ceases to be a director of the Company. Deferred Share Units are settled in cash based on the prevailing Crescent Point share price.

The following table reconciles the number of restricted shares and DSUs for the year ended December 31, 2013:

	Restricted Shares	Deferred Share Units
Balance, beginning of year	3,366,492	51,318
Granted	1,413,271	24,062
Redeemed	(2,058,318)	-
Forfeited	(133,302)	-
Balance, end of year	2,588,143	75,380

For the year ended December 31, 2013, the Company calculated total share-based compensation, net of estimated forfeitures and forfeiture true-ups, of $90.8 million (December 31, 2012 - $68.8 million), of which $23.1 million was capitalized (December 31, 2012 - $17.7 million).

21. PER SHARE AMOUNTS

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

	2013	2012
Weighted average shares – basic	**386,253,999**	329,410,803
Dilutive impact of restricted shares	**1,476,739**	2,370,430
Weighted average shares – diluted	**387,730,738**	331,781,233

22. FINANCIAL INSTRUMENTS AND DERIVATIVES

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

Crescent Point's derivative assets and liabilities are transacted in active markets. Crescent Point's long-term investments are transacted in active and non-active markets. The Company classifies the fair value of these transactions according to the following fair value hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 - Values are based on unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date.
- Level 2 - Values are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace. Prices in Level 2 are either directly or indirectly observable as of the reporting date.
- Level 3 - Values are based on prices or valuation techniques that are not based on observable market data.

Accordingly, Crescent Point's derivative assets and liabilities are classified as Level 2. Long-term investments are classified as Level 1, Level 2 or Level 3 depending on the valuation methods and inputs used, whether the applicable company is publicly traded or private, and whether the investment is comprised of common shares or common share purchase warrants. Assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement within the fair value hierarchy.

Crescent Point's valuation of investments in private companies is based primarily on recent trading activity in the relevant company's common shares. Crescent Point validates these valuations using a variety of peer comparison metrics and industry data. The Company's finance department is responsible for performing the valuation of financial instruments, including the calculation of Level 3 fair values. Refer to Note 5 for changes in the Company's Level 3 investments.

Discussions of the fair values and risks associated with financial assets and liabilities, as well as summarized information related to derivative positions are detailed below:

a) Carrying Amount and Fair Value of Financial Instruments

The fair value of cash, accounts receivable, reclamation fund, accounts payable and accrued liabilities and dividends payable approximate their carrying amount due to the short-term nature of those instruments. The fair value of the amounts drawn on bank credit facilities is equal to its carrying amount as the facility bears interest at floating rates and credit spreads within the facility are indicative of market rates. These financial instruments are classified as financial assets and liabilities at amortized cost and are reported at amortized cost.

The following table summarizes the recurring fair value measurement information for financial assets and liabilities as of December 31, 2013:

($000s)	2013 Carrying Value	2013 Fair Value	Quoted prices in active markets for identical assets (Level1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Derivatives	51,224	51,224	-	51,224	-
Long-term investments [1]	74,229	74,229	24,259	-	49,970
	125,453	125,453	24,259	51,224	49,970
Financial liabilities					
Derivatives	125,234	125,234	-	125,234	-
Senior guaranteed notes [2]	1,187,519	1,202,304	-	-	-
	1,312,753	1,327,538	-	125,234	-

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

(2) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

The following table summarizes the recurring fair value measurement information for financial assets and liabilities as of December 31, 2012:

($000s)	2012 Carrying Value	2012 Fair Value	Quoted prices in active markets for identical assets (Level1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Financial assets					
Derivatives	61,698	61,698	-	61,698	-
Long-term investments [1]	84,906	84,906	28,241	73	56,592
	146,604	146,604	28,241	61,771	56,592
Financial liabilities					
Derivatives	23,832	23,832	-	23,832	-
Senior guaranteed notes [2]	821,466	894,756	-	-	-
	845,298	918,588	-	23,832	-

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

(2) The senior guaranteed notes are classified as financial liabilities at amortized cost and are reported at amortized cost. The notes denominated in US dollars are translated to Canadian dollars at the period end exchange rate. The fair value of the notes is calculated based on current interest rates and is not recorded in the financial statements.

Investment in marketable securities

In March 2012, the Company disposed of its investment in marketable securities for proceeds of $0.6 million, resulting in a realized gain of less than $0.1 million recognized in net income.

Derivative assets and liabilities

Derivative assets and liabilities arise from the use of derivative contracts. The Company's derivative financial instruments are classified as fair value through profit or loss and are reported at fair value with changes in fair value recorded in net income.

The following table summarizes the fair value as at December 31, 2013 and the change in fair value for the year ended December 31, 2013:

($000s)	Commodity contracts [1]	Interest contracts	CCIRS contracts [2]	Foreign exchange contracts	Total
Derivative assets / (liabilities), beginning of year	43,337	(8,518)	2,840	207	37,866
Unrealized change in fair value	(154,905)	1,982	41,254	(207)	(111,876)
Derivative assets / (liabilities), end of year	(111,568)	(6,536)	44,094	-	(74,010)
Derivative assets, end of year	3,512	-	47,712	-	51,224
Derivative liabilities, end of year	(115,080)	(6,536)	(3,618)	-	(125,234)

(1) Includes oil, gas and power contracts.

(2) Includes cross currency principal swap contract.

The following table summarizes the fair value as at December 31, 2012 and the change in fair value for the year ended December 31, 2012:

($000s)	Commodity contracts [1]	Interest contracts	CCIRS contracts [2]	Foreign exchange contracts	Total
Derivative assets / (liabilities), beginning of year	(131,256)	(15,575)	(582)	21	(147,392)
Acquired through capital acquisitions	(466)	-	-	-	(466)
Unrealized change in fair value	175,059	7,057	3,422	186	185,724
Derivative assets / (liabilities), end of year	43,337	(8,518)	2,840	207	37,866
Derivative assets, end of year	52,430	-	9,059	209	61,698
Derivative liabilities, end of year	(9,093)	(8,518)	(6,219)	(2)	(23,832)

(1) Includes oil, gas and power contracts.

(2) Includes cross currency principal swap contract.

Offsetting Financial Assets and Liabilities

Financial assets and liabilities are only offset if the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. The Company offsets derivative assets and liabilities when the counterparty, commodity, currency and timing of settlement are the same. The following table summarizes the gross asset and liability positions of the Company's financial derivatives by contract that are offset on the balance sheet as at December 31, 2013 and December 31, 2012:

			2013			2012
($000s)	Asset	Liability	Net	Asset	Liability	Net
Gross amount	55,614	(129,624)	(74,010)	76,192	(38,326)	37,866
Amount offset	(4,390)	4,390	-	(14,494)	14,494	-
Net amount	51,224	(125,234)	(74,010)	61,698	(23,832)	37,866

b) Risks Associated with Financial Assets and Liabilities

The Company is exposed to financial risks from its financial assets and liabilities. The financial risks include market risk relating to commodity prices, interest rates and foreign exchange rates as well as credit and liquidity risk.

Market Risk

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

Commodity Price Risk

The Company is exposed to commodity price risk on crude oil and natural gas revenues as well as power on electricity consumption. As a means to mitigate the exposure to commodity price volatility, the Company has entered into various derivative agreements and physical contracts. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors.

Crude oil - To partially mitigate exposure to crude oil commodity price risk, the Company enters into option contracts and swaps, which manage the Cdn$ WTI price fluctuations. The Company also enters physical delivery and derivative WTI price differential contracts which manage the spread between US$ WTI and various stream prices. The Company manages physical delivery

contracts on a month-to-month spot and on a term contract basis. As at December 31, 2013, Crescent Point had committed, on a term contract basis, to deliver an average of 14,000 bbl/d of crude oil on railways from January 2014 to June 2014.

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

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

The following table summarizes the sensitivity of the fair value of the Company's derivative positions as at December 31, 2013 and 2012 to fluctuations in commodity prices or differentials, with all other variables held constant. When assessing the potential impact of these commodity price or differential changes, the Company believes 10 percent volatility is a reasonable measure. Fluctuations in commodity prices or differentials potentially could have resulted in unrealized gains (losses) impacting income before tax as follows:

($000s)	Impact on Income Before Tax Year ended December 31, 2013		Impact on Income Before Tax Year ended December 31, 2012	
	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Commodity price				
Crude oil	(308,532)	305,675	(223,326)	226,385
Natural gas	(4,006)	4,006	(2,013)	2,013
Power	264	(264)	280	(280)

Interest Rate Risk

The Company is exposed to interest rate risk on bank credit facilities to the extent of changes in the prime interest rate. For the year ended December 31, 2013, a one percent increase or decrease in the interest rate on floating rate debt would have amounted to a $3.5 million impact on income before tax.

The Company partially mitigates its exposure to interest rate changes by entering into interest rate swap transactions. The following sensitivities show the resulting unrealized gains (losses) and the impact on income before tax of the respective changes in the applicable forward interest rates as at December 31, 2013 and 2012 with all other variables held constant:

($000s)	Impact on Income Before Tax Year ended December 31, 2013		Impact on Income Before Tax Year ended December 31, 2012	
Forward interest rates	Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
Interest rate swaps	329	(329)	803	(803)

Foreign Exchange Risk

Foreign exchange risk arises from changes in foreign exchange rates that may affect the fair value or future cash flows of the Company's financial assets or liabilities. As the Company operates in Canada and the U.S., fluctuations in the exchange rate between the US/Canadian dollars can have a significant effect on reported results. The Company is exposed to foreign exchange risk in relation to its US dollar denominated senior guaranteed notes, investment in U.S. subsidiaries and in relation to its crude oil sales.

Concurrent with the issuance of US$953.0 million senior guaranteed notes, the Company entered into CCIRS with a syndicate of financial institutions. Under the terms of the CCIRS, the US dollar amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of $953.2 million. Concurrent with the issuance of US$30.0 million senior guaranteed notes, the Company entered a cross currency principal swap which fixed the principal repayment at a notional amount of $32.2 million.

The Company can partially mitigate its exposure to foreign exchange rate changes by entering into US dollar swaps. To partially mitigate the foreign exchange risk relating to crude oil sales, the Company has fixed crude oil contracts to settle in Cdn$ WTI.

The following sensitivities show the resulting unrealized gains (losses) and the impact on income before tax of the respective changes in the period end and applicable forward foreign exchange rates at December 31, 2013 and 2012 with all other variables held constant:

($000s)	Exchange Rate	Impact on Income Before Tax Year ended December 31, 2013		Impact on Income Before Tax Year ended December 31, 2012	
Cdn$ relative to US$		Increase 10%	Decrease 10%	Increase 10%	Decrease 10%
US dollar swaps	Forward	-	-	(4,059)	4,059
US dollar senior guaranteed notes	Period End	104,552	(104,552)	68,947	(68,947)
Cross currency interest rate swaps	Forward	(113,694)	113,694	(81,301)	81,301
Cross currency principal swaps	Forward	(3,230)	3,230	(3,173)	3,173

Credit Risk

Credit risk is the risk that one party to a financial instrument will cause a financial loss for the other party by failing to discharge an obligation. A substantial portion of the Company's accounts receivable are with customers in the oil and gas industry and are subject to normal industry credit risks. The Company monitors the creditworthiness and concentration of credit with customers of its physical oil and gas sales. The Company is authorized to transact derivative contracts with counterparties rated A (or equivalent) or better, based on the lowest rating of the three ratings providers. Should one of the Company's financial counterparties be downgraded below the A rating limit, the Chief Financial Officer will advise the Audit Committee and provide recommendations to minimize the Company's credit risk to that counterparty. The maximum credit exposure associated with accounts receivable is the total carrying amount and the maximum exposure associated with the derivative instruments approximates their fair value.

To further mitigate credit risk associated with its physical sales portfolio, Crescent Point has secured credit insurance from a global credit insurance provider. This policy provides credit coverage for approximately 30 percent of the Company's physical sales portfolio. Crescent Point believes this insurance policy is a prudent component of its formal credit policies and procedures.

Less than 3 percent of the Company's accounts receivable balance at December 31, 2013 is outstanding for more than 90 days and the Company considers the entire balance to be collectible.

Liquidity Risk

The timing of undiscounted cash outflows relating to the financial liabilities outstanding at December 31, 2013 is outlined in the table below:

($000s)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Accounts payable and accrued liabilities	789,305	-	-	-	789,305
Dividends payable	90,849	-	-	-	90,849
Derivative liabilities (1)	95,360	22,144	-	-	117,504
Senior guaranteed notes (2)	56,108	242,717	210,337	969,357	1,478,519
Bank credit facilities (3)	-	546,595	-	-	546,595

(1) These amounts exclude undiscounted cash outflows pursuant to the CCIRS and cross currency principal swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCIRS and cross currency principal swaps, which fix the amounts due in Canadian dollars.

(3) These amounts exclude interest payable on amounts drawn on the bank credit facilities.

The timing of undiscounted cash outflows relating to the financial liabilities outstanding at December 31, 2012 is outlined in the table below:

($000s)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Accounts payable and accrued liabilities	655,191	-	-	-	655,191
Dividends payable	86,182	-	-	-	86,182
Derivative liabilities (1)	19,702	8,412	271	-	28,385
Senior guaranteed notes (2)	43,031	172,114	95,080	785,674	1,095,899
Bank credit facilities (3)	-	653,123	-	-	653,123

(1) These amounts exclude undiscounted cash outflows pursuant to the CCIRS and cross currency principal swaps.

(2) These amounts include the notional principal and interest payments pursuant to the CCIRS and cross currency principal swaps, which fix the amounts due in Canadian dollars.

(3) These amounts exclude interest payable on amounts drawn on the bank credit facilities.

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. The Company manages its liquidity risk through cash and debt management. As disclosed in Note 15, Crescent Point targets an average net debt to funds flow from operations ratio of approximately 1.0 times.

In managing liquidity risk, the Company has access to a wide range of funding at competitive rates through capital markets and banks. At December 31, 2013, the Company had available unused borrowing capacity on bank credit facilities of approximately $1.5 billion, including $3.9 million letters of credit drawn on the facility. Crescent Point believes it has sufficient funding to meet its foreseeable spending requirements.

Included in the Company's bank credit facilities balance of $546.6 million at December 31, 2013 (December 31, 2012 - $653.1 million) are obligations of $460.0 million (December 31, 2012 - $400.0 million) of bankers' acceptances, obligations of $89.8 million (December 31, 2012 - $257.3 million) for borrowings under the operating and syndicated prime loans, partially offset by prepaid credit facility renewal fees of $2.1 million (December 31, 2012 - $3.2 million) and prepaid interest on bankers' acceptances of $1.1 million (December 31, 2012 - $1.0 million). These amounts are fully supported and management expects that they will continue to be supported by revolving credit facilities that have no repayment requirements until maturity, other than interest.

c) Derivative Contracts

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

The following is a summary of the derivative contracts in place as at December 31, 2013:

Financial WTI Crude Oil Derivative Contracts – Canadian Dollar [1]						
Term	Volume (bbls/d)	Average Swap Price ($/bbl)	Average Collar Sold Call Price ($/bbl)	Average Collar Bought Put Price ($/bbl)	Average Bought Put Price ($/bbl)	Average Put Premium ($/bbl)
2014	57,097	96.71	102.79	88.08	98.12	4.73
2015	26,750	92.35	97.60	87.41	-	-
2016	18,000	90.34	-	-	-	-
2017 January - March	6,000	90.31	-	-	-	-

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

Financial AECO Natural Gas Derivative Contracts – Canadian Dollar [1]		
Term	Average Volume (GJ/d)	Average Swap Price ($/GJ)
2014	14,493	3.54
2015	13,332	3.55
2016 January – October	5,790	3.67

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

Financial Power Derivative Contracts – Canadian Dollar			
Term	Contract	Volume (MW/h)	Fixed Rate ($/MW/h)
2014	Swap	3.0	75.00
2015	Swap	3.0	49.50

Financial Interest Rate Derivative Contracts – Canadian Dollar			
Term	Contract	Notional Principal ($)	Fixed Annual Rate (%)
January 2014 – May 2015	Swap	25,000,000	2.90
January 2014 – May 2015	Swap	25,000,000	3.50
January 2014 – May 2015	Swap	50,000,000	3.09
January 2014 – June 2015	Swap	50,000,000	3.78
January 2014 – July 2015	Swap	50,000,000	3.63

Financial Cross Currency Interest Rate Derivative Contracts					
Term	Contract	Receive Notional Principal (US$)	Fixed Annual Rate (US%)	Pay Notional Principal (Cdn$)	Fixed Annual Rate (Cdn%)
January 2014 – March 2015	Swap	37,500,000	4.71	38,287,500	5.24
January 2014 – April 2016	Swap	52,000,000	3.93	50,128,000	4.84
January 2014 – March 2017	Swap	67,500,000	5.48	68,917,500	5.89
January 2014 – April 2018	Swap	31,000,000	4.58	29,884,000	5.32
January 2014 – June 2018	Swap	20,000,000	2.65	20,350,000	3.52
January 2014 – May 2019	Swap	68,000,000	3.39	66,742,000	4.53
January 2014 – March 2020	Swap	155,000,000	6.03	158,255,000	6.45
January 2014 – April 2021	Swap	82,000,000	5.13	79,048,000	5.83
January 2014 – May 2022	Swap	170,000,000	4.00	166,855,000	5.03
January 2014 – June 2023	Swap	270,000,000	3.78	274,725,000	4.32

Financial Cross Currency Principal Derivative Contracts			
Settlement Date	Contract	Receive Notional Principal (US$)	Pay Notional Principal (Cdn$)
May 22, 2022	Swap	30,000,000	32,241,000

Concurrent with the issuance of US$953.0 million senior guaranteed notes, the Company entered into CCIRS with a syndicate of financial institutions. Under the terms of the CCIRS, the US dollar amount of the notes was fixed for purposes of interest and principal repayments at a notional amount of $953.2 million. Concurrent with the issuance of US$30.0 million senior guaranteed notes, the Company entered a cross currency principal swap which fixed the principal repayment at a notional amount of $32.2 million.

23. RELATED PARTY TRANSACTIONS

All related party transactions are recorded at the exchange amount.

During the year ended December 31, 2013, Crescent Point recorded $0.8 million (December 31, 2012 - $1.9 million) of legal fees in the normal course of business to a law firm of which a partner is the Company's corporate secretary. Crescent Point also recorded $0.3 million during the year ended December 31, 2013, (December 31, 2012 - $0.8 million) of legal fees in the normal course of business to a law firm of which a partner is a director of the Company.

Compensation of Key Management Personnel

Key management personnel of the Company consist of its directors and executive officers. In addition to the directors fees and salaries paid to the directors and officers, respectively, the directors participate in the Restricted Share Bonus Plan and DSU Plan and the officers participate in the Restricted Share Bonus Plan. The compensation relating to key management personnel for the year recorded as general and administrative expenses was $12.1 million (December 31, 2012 - $11.3 million) and share-based compensation costs were $37.6 million (December 31, 2012 – $30.8 million).

24. COMMITMENTS

At December 31, 2013, the Company had contractual obligations and commitments as follows:

($000s)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Operating leases (building and vehicle leases) (1)	18,343	48,242	48,241	281,817	396,643
Transportation commitments	1,705	461	144	13	2,323
Derivative contract premiums	15,697	-	-	-	15,697
Total contractual commitments	35,745	48,703	48,385	281,830	414,663

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

At December 31, 2012, the Company had contractual obligations and commitments as follows:

($000s)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Operating leases (building and vehicle leases) (1)	14,921	26,535	43,449	284,364	369,269
Capital commitments (2)	60,114	-	-	-	60,114
Derivative contract premiums	10,804	-	-	-	10,804
Total contractual commitments	85,839	26,535	43,449	284,364	440,187

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

(2) Included in capital commitments is the expected remaining cost of the two-year agreement terminating December 31, 2013, with a U.S. fracture stimulation company with operations in North Dakota.

25. SIGNIFICANT SUBSIDIARIES

The Company has the following significant subsidiaries, each owned 100% directly and indirectly, at December 31, 2013:

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

26. SUPPLEMENTAL DISCLOSURES

Income Statement Presentation

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

($000s)	**2013**	2012
Operating	**60,387**	47,043
General and administrative	**41,910**	34,323
Share-based compensation	**67,752**	51,141
Total compensation expenses	**170,049**	132,507

Cash Flow Statement Presentation

($000s)	**2013**	2012
Operating activities		
Changes in non-cash working capital:		
Accounts receivable	**(66,537)**	70,241
Prepaids and deposits	**2,996**	(3,642)
Accounts payable and accrued liabilities	**6,192**	(95,974)
	(57,349)	(29,375)
Investing activities		
Changes in non-cash working capital:		
Accounts receivable	**19,105**	435
Accounts payable and accrued liabilities	**133,068**	76,308
	152,173	76,743
Financing activities		
Changes in non-cash working capital:		
Dividends payable	**4,667**	19,936

27. GEOGRAPHICAL DISCLOSURE

As at December 31, 2013, Crescent Point's non-current assets related to the U.S. foreign operations is $1.6 billion (December 31, 2012 - $1.3 billion). For the year ended December 31, 2013, Crescent Point's oil and gas revenue related to the U.S. foreign operations is $335.5 million (December 31, 2012 - $67.0 million).

28. SUBSEQUENT EVENTS

New York Stock Exchange ("NYSE") Listing

On January 22, 2014, Crescent Point's common shares began trading on the NYSE under the ticker symbol "CPG".

Directors

Peter Bannister, Chairman [1] [3] [4]

Ken Cugnet [3] [4] [5]

Hugh Gillard [1] [2] [5]

Gerald Romanzin [1] [2] [3]

Scott Saxberg [4]

Greg Turnbull [2] [5]

[1] Member of the Audit Committee of the Board of Directors

[2] Member of the Compensation Committee of the Board of Directors

[3] Member of the Reserves Committee of the Board of Directors

[4] Member of the Health, Safety and Environment Committee of the Board of Directors

[5] Member of the Corporate Governance and Nominating Committee

Officers

Scott Saxberg
President and Chief Executive Officer

Greg Tisdale
Chief Financial Officer

C. Neil Smith
Chief Operating Officer

Brad Borggard
Vice President, Corporate Planning

Derek Christie
Vice President, Exploration and Geosciences

Ryan Gritzfeldt
Vice President, Engineering East

Ken Lamont
Vice President, Finance and Treasurer

Tamara MacDonald
Vice President, Land

Trent Stangl
Vice President, Marketing and Investor Relations

Steve Toews
Vice President, Engineering West

Mark Eade
Corporate Secretary

Head Office

Suite 2800, 111 - 5th Avenue S.W.
Calgary, Alberta T2P 3Y6
Tel: (403) 693-0020
Fax: (403) 693-0070
Toll Free: (888) 693-0020

Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings:

Olympia Trust Company
2300, 125 - 9th Avenue S.E.
Calgary, Alberta T2G 0P6
Tel: (403) 261-0900

Stock Exchanges

Toronto Stock Exchange - TSX
New York Stock Exchange - NYSE

Stock Symbol

CPG

Investor Contacts

Scott Saxberg
President and Chief Executive Officer
(403) 693-0020

Greg Tisdale
Chief Financial Officer
(403) 693-0020

Trent Stangl
Vice President, Marketing and Investor Relations
(403) 693-0020

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") is dated March 11, 2014 and should be read in conjunction with the audited consolidated financial statements for the year ended December 31, 2013 for a full understanding of the financial position and results of operations of Crescent Point Energy Corp. (the "Company" or "Crescent Point").

The audited consolidated financial statements and comparative information for the year ended December 31, 2013 have been prepared in accordance with International Financial Reporting Standards ("IFRS").

STRUCTURE OF THE BUSINESS

The principal undertakings of Crescent Point are to carry on the business of acquiring, developing and holding interests in petroleum and natural gas properties and assets related thereto through a general partnership and wholly owned subsidiaries. Amounts in this report are in Canadian dollars unless noted otherwise. References to "US$" are to United States ("US") dollars.

Non-GAAP Financial Measures

Throughout this MD&A, the Company uses the terms "funds flow from operations", "funds flow from operations per share", "funds flow from operations per share - diluted", "operating income", "operating income per share", "operating income per share - diluted", "net debt", "netback", "market capitalization" and "total capitalization". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Funds flow from operations is calculated based on cash flow from operating activities before changes in non-cash working capital, transaction costs and decommissioning expenditures. Funds flow from operations per share and funds flow from operations per share - diluted are calculated as funds flow from operations divided by the number of weighted average basic and diluted shares outstanding, respectively. Management utilizes funds flow from operations as a key measure to assess the ability of the Company to finance dividends, operating activities, capital expenditures and debt repayments. Funds flow from operations as presented is not intended to represent cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with IFRS.

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

($000s)	**2013**	2012	% Change
Cash flow from operating activities	**1,973,332**	1,543,943	28
Changes in non-cash working capital	**57,349**	29,375	95
Transaction costs	**5,761**	16,436	(65)
Decommissioning expenditures	**11,375**	12,096	(6)
Funds flow from operations	**2,047,817**	1,601,850	28

Operating income is calculated based on net income before amortization of exploration and evaluation ("E&E") undeveloped land, unrealized derivative gains or losses, unrealized foreign exchange gain or loss on translation of US dollar senior guaranteed notes and unrealized gains or losses on marketable securities and long-term investments. Operating income per share and operating income per share - diluted are calculated as operating income divided by the number of weighted average basic and diluted shares outstanding, respectively. Management utilizes operating income to present a measure of financial performance that is more comparable between periods. Operating income as presented is not intended to represent net earnings or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles net income to operating income:

($000s)	**2013**	2012	% Change
Net income	**144,876**	190,653	(24)
Amortization of E&E undeveloped land	**275,504**	247,883	11
Unrealized derivative (gains) losses	**111,876**	(185,724)	(160)
Unrealized foreign exchange (gain) loss on translation of US dollar senior guaranteed notes	**60,994**	(5,774)	(1,156)
Unrealized loss on long-term investments	**10,677**	89,472	(88)
Deferred tax relating to adjustments	**(118,239)**	(32,942)	259
Operating income	**485,688**	303,568	60

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

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

($000s)	**2013**	2012	% Change
Long-term debt	**1,734,114**	1,474,589	18
Accounts payable and accrued liabilities	**789,305**	655,191	20
Dividends payable	**90,849**	86,182	5
Cash	**(15,941)**	-	-
Accounts receivable	**(352,519)**	(301,770)	17
Prepaids and deposits	**(5,532)**	(8,484)	(35)
Long-term investments	**(74,229)**	(84,906)	(13)
Excludes:			
Equity settled component of dividends payable	**(25,799)**	(58,302)	(56)
Unrealized foreign exchange on translation of US dollar senior guaranteed notes	**(63,170)**	(2,176)	2,803
Net debt	**2,077,078**	1,760,324	18

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 used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

Market capitalization is calculated by applying the period end closing share trading price to the number of shares outstanding. Market capitalization is an indication of enterprise value.

Total capitalization is calculated as market capitalization plus net debt. Total capitalization is used by management to assess the amount of debt leverage used in the Company's capital structure. Refer to the Liquidity and Capital Resources section in this MD&A.

Results of Operations

Production

	2013	2012	% Change
Crude oil and NGL (bbls/d)	**109,129**	89,704	22
Natural gas (mcf/d)	**66,952**	54,284	23
Total (boe/d)	**120,288**	98,751	22
Crude oil and NGL (%)	**91**	91	-
Natural gas (%)	**9**	9	-
Total (%)	**100**	100	-

Production increased by 22 percent year over year to 120,288 boe/d in 2013 from 98,751 boe/d in 2012, primarily due to the Company's successful drilling and fracture stimulation programs and the acquisition of Ute Energy Upstream Holdings LLC ("Ute") on November 29, 2012 which added approximately 7,800 boe/d of production, partially offset by natural declines.

In the year ended December 31, 2013, the Company drilled 737 (549.5 net) wells, focused primarily in the Viewfield Bakken resource play in southeast Saskatchewan, the Shaunavon resource play in southwest Saskatchewan and the Uinta Basin resource play in northeast Utah.

The Company's weighting to oil and NGL's in 2013 remained consistent with the comparative period.

Marketing and Prices

Average Selling Prices (1)	2013	2012	% Change
Crude oil and NGL ($/bbl)	**86.32**	80.51	7
Natural gas ($/mcf)	**3.61**	2.61	38
Total ($/boe)	**80.32**	74.57	8

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

Benchmark Pricing	2013	2012	% Change
Crude Oil Prices			
WTI crude oil (US$/bbl)	**98.00**	94.19	4
WTI crude oil (Cdn$/bbl)	**101.03**	94.19	7
LSB crude oil (Cdn$/bbl)	**91.85**	84.61	9
LSB oil differential (%)	**9**	10	(1)
WCS crude oil (Cdn$/bbl)	**75.15**	73.17	3
WCS oil differential (%)	**26**	22	4
Natural Gas Prices			
AECO natural gas (1) (Cdn$/mcf)	**3.17**	2.39	33
Foreign Exchange Rate			
Exchange rate (US$/Cdn$)	**0.97**	1.00	(3)

(1) The AECO natural gas price reported is the average daily spot price.

For the year ended December 31, 2013, the Company's average selling price for oil increased 7 percent from 2012, primarily as a result of a 4 percent increase in the US$ WTI benchmark price and a weaker Canadian dollar. Crescent Point's oil differential for the year ended December 31, 2013 was $14.71 per bbl, or 15 percent, compared to $13.68 per bbl, or 15 percent in 2012.

The Company's corporate oil differential was impacted by a slight narrowing of light oil differentials, largely offset by a widening of medium and heavy oil differentials and increased exposure to Uinta Basin production from the acquisition of Ute, which realizes an increased differential than the corporate average. In 2013, the Cdn$ WTI - LSB differential narrowed to 9 percent from 10 percent in 2012 and the Cdn$ WTI - WCS differential widened to 26 percent from 22 percent in 2012. The Company's Uinta Basin production realized an average oil differential of $19.22 per bbl, or 19 percent, in the year ended December 31, 2013.

The Company's exposure to medium and heavy oil differentials increased in 2013 due to the Company's growing production base in southwest Saskatchewan, which is typically sold at a premium to WCS prices. In addition, the Company is exposed to Yellow wax crude and Black wax crude oil differentials in the Uinta Basin.

Price differentials are expected to remain volatile in 2014. To partially mitigate these price risks, Crescent Point continues to deliver crude oil through its Saskatchewan, Alberta and Utah rail terminals, providing access to markets outside of the PADD II region. The Company also enters physical delivery and derivative WTI price differential contracts which manage the spread between US$ WTI and various stream prices. The Company manages physical delivery contracts on a month-to-month spot and on a term contract basis.

The Company's average selling price for gas in the year ended December 31, 2013 increased 38 percent from $2.61 per mcf in 2012 to $3.61 per mcf in 2013, primarily as a result of the 33 percent increase in AECO benchmark prices and the impact of NYMEX based pricing received on the Company's Utah and North Dakota gas production.

Derivatives

The following is a summary of the realized derivative gain (loss) on oil and gas derivative contracts:

($000s, except volume amounts)	**2013**	2012	% Change
Average crude oil volumes hedged (bbls/d) (1)	**53,296**	39,691	34
Crude oil realized derivative loss (1)	**(94,144)**	(28,861)	226
per bbl	**(2.36)**	(0.88)	168
Average natural gas volumes hedged (GJ/d) (2)	**14,197**	9,000	58
Natural gas realized derivative gain	**3,273**	11,257	(71)
per mcf	**0.13**	0.57	(77)
Average barrels of oil equivalent hedged (boe/d) (1)	**55,539**	41,113	35
Total realized derivative loss	**(90,871)**	(17,604)	416
per boe	**(2.07)**	(0.49)	322

(1) In the year ended December 31, 2013, the crude oil realized derivative loss includes the realized derivative gain on financial price differential contracts. The average crude oil volumes hedged and average barrels of oil equivalent hedged do not include the hedged volumes related to financial price differential contracts.

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

Management of cash flow variability is an integral component of Crescent Point's business strategy. Changing business conditions are monitored regularly and reviewed with the Board of Directors to establish risk management guidelines used by management in carrying out the Company's strategic risk management program. The risk exposure inherent in movements in the price of crude oil, natural gas and power, fluctuations in the US/Cdn dollar exchange rate and interest rate movements on long-term debt are all proactively managed by Crescent Point through the use of derivatives with investment-grade counterparties. The Company considers these derivative contracts to be an effective means to manage cash flow.

The Company's crude oil and natural gas derivatives are referenced to WTI and AECO, unless otherwise noted. Crescent Point utilizes a variety of derivatives, including swaps, collars and put options to protect against downward commodity price movements while providing the opportunity for some upside participation during periods of rising prices. For commodities, Crescent Point's risk management program allows for hedging a forward profile of 3½ years, and up to 65 percent, unless otherwise approved by the Board of Directors, net of royalty interest production.

With ongoing volatility of price differentials between WTI and western Canadian crude prices, Crescent Point has expanded its risk management programs to include the hedging of these differentials. The Company uses a combination of financial derivatives and fixed differential physical contracts to hedge these price differentials. For price differential hedging, Crescent Point's risk management program allows for hedging a forward profile of 3½ years, and up to 35 percent net of royalty interest production.

The Company recorded a total realized derivative loss of $90.9 million for the year ended December 31, 2013, compared to a loss of $17.6 million in 2012.

The Company's realized derivative loss for oil was $94.1 million for the year ended December 31, 2013, compared to a realized derivative loss of $28.9 million in 2012. The increased realized loss in 2013 is largely attributable to an increase in the Cdn$ WTI benchmark price and the increase in oil volumes hedged as a result of increased production, partially offset by an increase in the Company's average derivative oil price. During the year ended December 31, 2013, the Company's average derivative oil price increased by 4 percent or $3.99 per bbl, from $92.20 per bbl in 2012 to $96.19 per bbl in 2013.

Crescent Point's realized derivative gain for gas was $3.3 million for the year ended December 31, 2013, compared to $11.3 million in 2012. The decreased realized gain in 2013 is largely attributable to the decrease in the Company's average derivative gas price and the increase in the AECO benchmark price, partially offset by an increase in gas volumes hedged as a result of increased production. During the year ended December 31, 2013, the Company's average derivative gas price decreased from $5.68 per GJ in 2012 to $3.64 per GJ in 2013 and the AECO benchmark price increased by 33 percent.

The Company has not designated any of its risk management activities as accounting hedges under International Accounting Standard 39,*Financial Instruments: Recognition and Measurement* and, accordingly, has fair valued its derivatives.

The following is a summary of the Company's unrealized derivative gain (loss):

($000s)	**2013**	2012	% Change
Crude oil	**(153,319)**	185,854	(182)
Natural gas	**(1,554)**	(9,140)	(83)
Interest	**1,982**	7,057	(72)
Power	**(30)**	(1,655)	(98)
Cross currency interest rate	**40,678**	3,936	933
Cross currency principal	**574**	(514)	(212)
Foreign exchange	**(207)**	186	(211)
Total unrealized derivative gain (loss)	**(111,876)**	185,724	(160)

The Company recognized a total unrealized derivative loss of $111.9 million for the year ended December 31, 2013 compared to a total unrealized derivative gain of $185.7 million in 2012, primarily due to a $153.3 million unrealized loss on crude oil contracts in 2013 compared to a $185.9 million unrealized gain in 2012. The unrealized oil derivative loss for the year ended December 31, 2013 is primarily attributable to the increase in the Cdn$ WTI forward benchmark price at December 31, 2013 compared to December 31, 2012. The unrealized oil derivative gain for the year ended December 31, 2012 is primarily attributable to the decrease in the Cdn$ WTI forward benchmark price at December 31, 2012 compared to December 31, 2011.

The total unrealized derivative loss in 2013 was partially offset by a $40.7 million unrealized gain on Cross Currency Interest Rate Swaps (“CCIRS”) compared to a $3.9 million unrealized gain in 2012. The unrealized CCIRS derivative gain for the year ended December 31, 2013 was primarily the result of the weaker forward Canadian dollar at December 31, 2013 compared to December 31, 2012 and the maturity of out of the money contract months. The unrealized CCIRS derivative gain for the year ended December 31, 2012 was primarily the result of the weaker forward Canadian dollar, specifically from 2017 onwards, at December 31, 2012 compared to December 31, 2011, and the maturity of out of the money contract months.

Revenues

($000s) [1]	**2013**	2012	% Change
Crude oil and NGL sales	**3,438,159**	2,643,181	30
Natural gas sales	**88,289**	51,813	70
Total oil and gas sales	**3,526,448**	2,694,994	31

(1) Revenue is reported before transportation charges and realized derivatives .

Crude oil and NGL sales increased 30 percent in the year ended December 31, 2013, from $2.6 billion in 2012 to $3.4 billion in 2013, primarily due to the 22 percent increase in Crescent Point's production and the 7 percent increase in realized prices. The increased production in 2013 is primarily due to the Company's successful drilling and fracture stimulation programs and the acquisition of Ute completed in 2012. The increase in realized prices is largely a result of the 7 percent increase in the Cdn$ WTI benchmark price as compared to 2012.

Natural gas sales increased 70 percent in the year ended December 31, 2013 compared to 2012. The increase is primarily due to the 38 percent increase in realized natural gas prices and the 23 percent increase in natural gas production. The increase in the realized natural gas price is largely due to the increase in the AECO benchmark price and the impact of NYMEX based pricing received on the Company's Utah and North Dakota gas production. The increased natural gas production in 2013 is primarily due to 2012 acquisitions and successful drilling in Viewfield, partially offset by natural declines.

Royalties

($000, except % and per boe amounts)	**2013**	2012	% Change
Royalties	**644,240**	468,226	38
As a % of oil and gas sales	**18**	17	1
Per boe	**14.67**	12.95	13

Royalties increased 38 percent in the year ended December 31, 2013 compared to 2012. The increase is largely due to the 31 percent increase in oil and gas sales and the 1 percent increase in royalties as a percentage of sales.

Royalties as a percentage of sales for the year ended December 31, 2013 increased primarily due to growing revenues in the United States, with higher associated royalty burdens, partially offset by royalty holidays for new wells drilled in Viewfield. In 2013, oil and gas sales in the United States accounted for 13 percent of the Company's total oil and gas sales compared to 3 percent in 2012.

In the year ended December 31, 2013, 256.5 net wells were drilled in Viewfield of the 549.5 total net wells drilled by the Company.

Operating Expenses

($000, except per boe amounts)	**2013**	2012	% Change
Operating expenses	**505,060**	421,125	20
Per boe	**11.50**	11.65	(1)

Operating expenses per boe decreased 1 percent in the year ended December 31, 2013 compared to 2012. The decrease was primarily the result of lower well servicing costs, largely offset by higher chemical costs.

Operating expenses increased 20 percent in the year ended December 31, 2013 compared to 2012, primarily as a result of the growth in the Company's production from the successful execution of the drilling and development program and the acquisitions completed in 2012.

Transportation Expenses

($000s, except per boe amounts)	**2013**	2012	% Change
Transportation expenses	**95,317**	66,147	44
Per boe	**2.17**	1.83	19

Transportation expenses per boe increased 19 percent in the year ended December 31, 2013 compared to 2012. The increase is primarily due to increased clean oil trucking costs resulting from increased oil deliveries through the Company's rail terminals in Saskatchewan, Alberta and Utah.

Transportation expenses increased 44 percent in the year ended December 31, 2013 compared to 2012, primarily as a result of the growth in the Company's production and the increase in per boe transportation expenses as noted above.

Netbacks

	2013			2012	
	Crude Oil and NGL ($/bbl)	**Natural Gas ($/mcf)**	**Total ($/boe)**	Total ($/boe)	% Change
Average selling price	**86.32**	**3.61**	**80.32**	74.57	8
Royalties	**(15.95)**	**(0.36)**	**(14.67)**	(12.95)	13
Operating expenses	**(12.21)**	**(0.76)**	**(11.50)**	(11.65)	(1)
Transportation expenses	**(2.14)**	**(0.41)**	**(2.17)**	(1.83)	19
Netback prior to realized derivatives	**56.02**	**2.08**	**51.98**	48.14	8
Realized gain (loss) on derivatives	**(2.36)**	**0.13**	**(2.07)**	(0.49)	322
Netback	**53.66**	**2.21**	**49.91**	47.65	5

The Company's netback for the year ended December 31, 2013 increased 5 percent to $49.91 per boe from $47.65 per boe in 2012. The increase in the Company's netback is primarily the result of the increase in average selling price largely due to the increase in the Cdn$ WTI benchmark price and the decrease in operating expenses, partially offset by increased royalties, realized derivative loss and transportation expenses.

General and Administrative Expenses

($000, except per boe amounts)	**2013**	2012	% Change
General and administrative costs	**86,547**	77,726	11
Capitalized	**(19,081)**	(14,342)	33
Total general and administrative expenses	**67,466**	63,384	6
Transaction costs	**(5,761)**	(16,436)	(65)
General and administrative expenses	**61,705**	46,948	31
Per boe	**1.41**	1.30	8

General and administrative expenses per boe increased 8 percent in the year ended December 31, 2013 compared to 2012, primarily due to decreased overhead recoveries recorded and increases in information technology costs. The decreased overhead recoveries are largely as a result of the Company's 2012 acquisitions having lower associated overhead recoveries.

General and administrative expenses increased 31 percent in the year ended December 31, 2013 compared to 2012. The increase is primarily due to increased employee-related costs as a result of the growth of the Company, including the expansion of operations in the United States, and the increase in per boe general and administrative expenses as noted above.

Transactions costs incurred in the year ended December 31, 2013 relate primarily to the acquisition and integration of Ute.

Interest Expense

($000, except per boe amounts)	**2013**	2012	% Change
Interest expense	**77,754**	71,530	9
Per boe	**1.77**	1.98	(11)

Interest expense per boe decreased 11 percent in the year ended December 31, 2013 compared to 2012, reflecting the successful production growth of the Company, partially offset by a slight increase in the Company's effective interest rate as a result of Crescent Point issuing long-term senior guaranteed notes at fixed interest rates.

Interest expense increased 9 percent in the year ended December 31, 2013 compared to 2012. This increase is primarily attributable to the higher average debt balance and the slight increase in the Company's effective interest rate. The higher average debt balance is the result of the Company's growth in production and fluctuations in working capital. The increased effective interest rate is a result of the Company issuing long-term senior guaranteed notes at fixed interest rates.

Crescent Point actively manages exposure to fluctuations in interest rates through interest rate swaps, short term bankers' acceptances and the issuance of long-term fixed rate senior guaranteed notes. Refer to the Derivatives section above for further information.

Foreign Exchange Gain (Loss)

($000s)	**2013**	2012	% Change
Realized			
Foreign exchange loss on cross currency interest rate swaps	**(4,308)**	(3,838)	12
Other foreign exchange gain	**1,134**	495	129
Unrealized			
Foreign exchange gain (loss) on translation of US dollar senior guaranteed notes	**(60,994)**	5,774	(1,156)
Other foreign exchange gain (loss)	**(337)**	361	(193)
Foreign exchange gain (loss)	**(64,505)**	2,792	(2,410)

The Company has senior guaranteed notes with aggregate principals of US$983.0 million and Cdn$142.0 million. The Company records unrealized foreign exchange gains or losses on the revaluation of the US denominated senior guaranteed notes and related accrued interest. During the year ended December 31, 2013, the Company recorded an unrealized foreign exchange loss of $61.0 million on translation of US dollar senior guaranteed notes and accrued interest compared to an unrealized gain of $5.8 million in 2012. The unrealized loss in 2013 is attributable to a weaker Canadian dollar as at December 31, 2013 as compared to December 31, 2012. The unrealized gain in 2012 is attributable to a stronger Canadian dollar as at December 31, 2012 as compared to December 31, 2011.

During the year ended December 31, 2013, the Company realized a foreign exchange loss of $4.3 million on the settlement of the CCIRS associated with interest payments made on the US dollar senior guaranteed notes, compared to a loss of $3.8 million in 2012. The increase in the realized loss for the year ended December 31, 2013 is primarily due to the additional CCIRS entered during 2013, partially offset by the weaker Canadian dollar for the year ended December 31, 2013.

Share-based Compensation Expense

($000s, except per boe amounts)	**2013**	2012	% Change
Share-based compensation costs	**90,838**	68,833	32
Capitalized	**(23,086)**	(17,692)	30
Share-based compensation expense	**67,752**	51,141	32
Per boe	**1.54**	1.41	9

During the year ended December 31, 2013, the Company recorded share-based compensation costs of $90.8 million, an increase of 32 percent from 2012. The increase in 2013 is primarily due to the increase in expenses associated with incentive related awards, partially offset by the decrease in expenses associated with base compensation restricted shares.

During the year ended December 31, 2013, the Company capitalized share-based compensation costs of $23.1 million, an increase of 30 percent from 2012. The increase is primarily the result of the increase in expenses associated with incentive related awards, partially offset by the decrease in base compensation restricted shares.

Restricted Share Bonus Plan

The Company has a Restricted Share Bonus Plan pursuant to which the Company may grant restricted shares to directors, officers, employees and consultants. The restricted shares vest on terms up to three years from the grant date as determined by the Board of Directors.

Restricted shareholders are eligible for monthly dividends on their restricted shares, immediately upon grant.

Under the Restricted Share Bonus Plan at December 31, 2013, the Company is authorized to issue up to 5,728,512 common shares (December 31, 2012 - 7,773,681 common shares), of which the Company had 2,588,143 restricted shares outstanding at December 31, 2013 (December 31, 2012 - 3,366,492 restricted shares outstanding).

Deferred Share Unit Plan

The Company has a Deferred Share Unit (“DSU”) plan for directors. Each DSU vests on the date of the grant, however, the settlement of the DSU occurs following a change of control or when the individual ceases to be a director of the Company. Deferred Share Units are settled in cash based on the prevailing Crescent Point share price. The Company had 75,380 DSUs outstanding at December 31, 2013 compared to 51,318 at December 31, 2012.

Depletion, Depreciation, Amortization and Impairment

($000s, except per boe amounts)	**2013**	2012	% Change
Depletion and depreciation	**1,185,104**	1,007,025	18
Amortization of E&E undeveloped land	**275,504**	247,883	11
Depletion, depreciation and amortization	**1,460,608**	1,254,908	16
Impairment	**98,291**	189,074	(48)
Depletion, depreciation, amortization and impairment	**1,558,899**	1,443,982	8
Per boe, before impairment	**33.27**	34.72	(4)
Per boe	**35.51**	39.95	(11)

The Company's depletion, depreciation and amortization ("DD&A") rate before impairment decreased 4 percent to $33.27 per boe for the year ended December 31, 2013 from $34.72 per boe in 2012. The decrease is primarily a result of proved plus probable reserve additions and decreased future development costs in the December 31, 2013 reserve report.

At December 31, 2013, the Company determined that the carrying amount of the Southern Alberta cash-generating unit ("CGU")exceeded its fair value less costs of disposal. The full amount of the impairment was attributed to property, plant and equipment ("PP&E") and, as a result, an impairment loss of $98.3 million was recorded as a component of depletion, depreciation, amortization and impairment expense. The Southern Alberta CGU is comprised primarily of properties in the early stages of development for which the operating results are included in the Canadian operating segment. The impairment in 2013 was largely a result of the exploratory nature of the Alberta Bakken resource play, which resulted in negative technical revisions to proved plus probable reserves and an increase in expected operating and abandonment costs.

The Company reported an impairment loss of $189.1 million for the year ended December 31, 2012 related to the Southern Alberta CGU largely as a result of the decrease in forecast benchmark commodity prices at December 31, 2012 compared to December 31, 2011, the early development stage of the properties and associated higher initial capital expenditures.

Other Loss

The Company recorded other losses of $10.1 million in the year ended December 31, 2013 compared to other losses of $60.5 million in 2012. The other losses in 2013 are primarily comprised of net unrealized losses on long-term investments. The other losses in 2012 are primarily comprised of net unrealized losses on long-term investments, partially offset by gains on the disposition of assets.

Taxes

($000s)	**2013**	2012	% Change
Current tax expense (recovery)	**173**	(1,418)	(112)
Deferred tax expense	**73,433**	19,436	278

Current Tax Expense (Recovery)

In the year ended December 31, 2013, the Company recorded current tax expense of $0.2 million compared to a current tax recovery of $1.4 million in 2012. The current tax expense in 2013 relates primarily to adjustments for business combinations completed in prior periods. The current tax recoveries in 2012 relate primarily to investment tax credits earned through research and development expenditures on drilling and development activities. Refer to the Company's December 31, 2013 Annual Information Form for information on the Company's expected tax horizon.

Deferred Tax Expense

In the year ended December 31, 2013, the Company recorded deferred tax expense of $73.4 million compared to $19.4 million in 2012. The increase in deferred tax expense is primarily due to a change in estimate regarding future usable tax pools and the Company's increased net income before taxes in 2013 and the effect of a tax pool recovery recorded in 2012.

Funds Flow, Cash Flow, Operating Income and Net Income

($000s, except per share amounts)	**2013**	2012	% Change
Funds flow from operations	**2,047,817**	1,601,850	28
Funds flow from operations per share - diluted	**5.28**	4.83	9
Cash flow from operating activities	**1,973,332**	1,543,943	28
Cash flow from operating activities per share - diluted	**5.09**	4.65	9
Operating income	**485,688**	303,568	60
Operating income per share - diluted	**1.25**	0.91	37
Net income	**144,876**	190,653	(24)
Net income per share - diluted	**0.37**	0.57	(35)

Funds flow from operations increased to $2.0 billion for the year ended December 31, 2013 from $1.6 billion in 2012 and increased to $5.28 per share - diluted from $4.83 per share - diluted. The increase in funds flow from operations is primarily the result of the increases in production volumes and the netback. Production volumes increased due to the Company's successful drilling and fracture stimulation programs and the Ute acquisition completed on November 29, 2012. The netback increased as a result of the increase in average selling price largely due to the increase in the Cdn$ WTI benchmark price and the decrease in operating expenses, partially offset by increased royalties, realized derivative loss, and transportation expenses. Funds flow from operations per share - diluted increased for the year ended December 31, 2013, primarily due to the reasons discussed above, partially offset by the impact of shares issued through the Company's Premium Dividend™ and Dividend Reinvestment Plan ("DRIP") and the August and November 2012 equity offerings.

Cash flow from operating activities increased 28 percent to $2.0 billion in the year ended December 31, 2013 compared to $1.5 billion in 2012, for the same reasons as discussed above and fluctuations in working capital, transaction costs and decommissioning expenditures. Cash flow from operating activities per share - diluted increased 9 percent to $5.09 per share - diluted in 2013, primarily due to the reasons discussed above, partially offset by the impact of shares issued through the Company's DRIP and the August and November 2012 equity offerings.

The Company reported operating income of $485.7 million in the year ended December 31, 2013 compared to $303.6 million in 2012, primarily as a result of the increase in funds flow from operations, partially offset by the increase in deferred tax expense and combined depletion and impairment expense. Operating income per share - diluted increased 37 percent to $1.25 per share - diluted in 2013, primarily due to reasons discussed above, partially offset by the impact of shares issued through the Company's DRIP and the August and November 2012 equity offerings.

The Company reported net income of $144.9 million in the year ended December 31, 2013 compared to $190.7 million in 2012, primarily as a result of the unrealized derivative and foreign exchange losses recorded in 2013 and the increase in depletion, depreciation, amortization and impairment expense and deferred tax expense, largely offset by the increase in funds flow from operations and the decrease in other losses.

As noted in the Derivatives section, the Company has not designated any of its risk management activities as accounting hedges under IAS 39*Financial Instruments: Recognition and Measurement*, and, accordingly, has fair valued its derivatives.

Crescent Point uses financial commodity derivatives, including swaps, collars and put options, to reduce the volatility of the selling price of its crude oil and natural gas production. This provides a measure of stability to the Company's cash flow and dividends over time. The Company's commodity derivatives portfolio extends out 3½ years from the current quarter.

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

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

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

Dividends

The following table provides a reconciliation of dividends:

($000s, except per share amounts)	**2013**	2012	% Change
Accumulated dividends, beginning of year	**3,673,971**	2,742,571	34
Dividends declared to shareholders	**1,081,551**	931,400	16
Accumulated dividends, end of year	**4,755,522**	3,673,971	29
Accumulated dividends per share, beginning of year	**23.31**	20.55	13
Dividends to shareholders per share	**2.76**	2.76	-
Accumulated dividends per share, end of year	**26.07**	23.31	12

The Company maintained monthly dividends of $0.23 per share during 2013.

Dividends increased 16 percent in the year ended December 31, 2013 compared to 2012. The increase in dividends in 2013 relates to an increase in the number of shares outstanding primarily due to the bought deal financings which closed in August and November 2012 and the issuance of shares to shareholders pursuant to the DRIP in lieu of cash dividends. Crescent Point suspended participation in the Premium component of the DRIP effective October 15, 2013.

Crescent Point believes it is well positioned to maintain monthly dividends as the Company continues to exploit and develop its resource plays. Crescent Point's risk management strategy minimizes exposure to commodity price volatility and provides a measure of sustainability to dividends through periods of fluctuating market prices.

Investments in Marketable Securities

In March 2012, the Company disposed of its investment in marketable securities for proceeds of $0.6 million, resulting in a realized gain of less than $0.1 million recognized in net income.

Long-Term Investments

Public Companies

The Company holds common shares and common share purchase warrants in publicly traded oil and gas companies. The investments are classified as financial assets at fair value through profit and loss and are fair valued with the resulting gain or loss recorded in net income. At December 31, 2013, the investments are recorded at a fair value of $24.3 million which is $79.7 million less than the original cost of the investments.

Private Companies

The Company holds common shares in private oil and gas companies. The investments are classified as financial assets at fair value through profit or loss and are fair valued with the resulting gain or loss recorded in net income. At December 31, 2013, the investments are recorded at a fair value of $50.0 million which is $17.0 million less than the original cost of the investments.

Other Long-Term Assets

At December 31, 2013, other long-term assets consist of $26.2 million related to the reclamation fund and $11.8 million of investment tax credits.

As part of Crescent Point's ongoing commitment to the environment and to reduce greenhouse gas emissions, Crescent Point has a voluntary reclamation fund for future decommissioning costs and environmental emissions reduction costs. During the year ended December 31, 2013, the Company contributed $0.70 per produced boe to the fund, of which $0.40 per boe was for future decommissioning costs and $0.30 per boe was directed to environmental emissions reduction.

The reclamation fund increased by $15.7 million during 2013 due to contributions of $30.7 million, partially offset by expenditures of $15.0 million. The expenditures included $11.4 million related primarily to decommissioning work completed in Alberta and southeast Saskatchewan. The remaining $3.6 million related to environmental emissions work completed primarily in Saskatchewan to reduce greenhouse gas emissions and to meet and exceed provincial and federal targets. Since inception, $86.7 million has been contributed to the reclamation fund and $60.6 million has been spent.

Related Party Transactions

All related party transactions are recorded at the exchange amount.

During the year ended December 31, 2013, Crescent Point recorded $0.8 million (December 31, 2012 - $1.9 million) of legal fees in the normal course of business to a law firm of which a partner is the Company's corporate secretary. Crescent Point also recorded $0.3 million during the year ended December 31, 2013 (December 31, 2012 - $0.8 million) of legal fees in the normal course of business to a law firm of which a partner is a director of the Company.

Key management personnel of the Company consist of its directors and executive officers. In addition to the directors fees and salaries paid to the directors and officers, respectively, the directors participate in the Restricted Share Bonus Plan and Deferred Share Unit Plan and the officers participate in the Restricted Share Bonus Plan. The compensation relating to key management personnel for the year recorded as general and administrative expenses was $12.1 million (December 31, 2012 - $11.3 million) and share-based compensation costs were $37.6 million (December 31, 2012 – $30.8 million).

Capital Expenditures

($000s)	**2013**	2012	% Change
Capital acquisitions (net) [(1)]	**118,267**	3,021,230	(96)
Development capital expenditures	**1,724,507**	1,488,947	16
Capitalized administration [(2)]	**19,081**	14,342	33
Office equipment	**3,285**	5,740	(43)
Total	**1,865,140**	4,530,259	(59)

(1) Capital acquisitions represent total consideration for the transactions including net debt and excluding transaction costs.

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

Capital Acquisitions

Minor Property Acquisitions and Dispositions

Crescent Point completed minor property acquisitions and dispositions during the year ended December 31, 2013 for net consideration of $118.3 million ($121.8 million was allocated to PP&E and E&E assets). These minor property acquisitions and dispositions were completed with full tax pools.

Development Capital Expenditures

The Company's development capital expenditures for the year ended December 31, 2013 were $1.7 billion compared to $1.5 billion in 2012. In 2013, 737 (549.5 net) wells were drilled with a success rate of 100 percent. The development capital for the year ended December 31, 2013 included $300.2 million on facilities, land and seismic.

Crescent Point's budgeted capital program for 2014 is $1.75 billion, not including acquisitions. The Company searches for acquisition opportunities that align with strategic parameters and evaluates each prospect on a case-by-case basis.

Goodwill

The Company's goodwill balance as at December 31, 2013 was $251.9 million which is unchanged from December 31, 2012. The goodwill balance is attributable to the corporate acquisitions completed during the period 2003 through 2012.

Decommissioning Liability

The decommissioning liability increased by $127.1 million during 2013 from $502.4 million at December 31, 2012 to $629.5 million at December 31, 2013. The increase relates to $115.3 million due to a change in future cost estimates, $32.6 million in respect of drilling, $14.2 million of accretion expense, $3.5 million as a result of net capital acquisitions and $3.2 million due to the revaluation of acquired liabilities, partially offset by $30.3 million due to a change in discount rate and $11.4 million for liabilities settled.

Liquidity and Capital Resources

Capitalization Table ($000s, except share, per share, ratio and percent amounts)	**December 31, 2013**	December 31, 2012
Net debt	**2,077,078**	1,760,324
Shares outstanding (1)	**394,993,566**	374,702,264
Market price at end of year (per share)	**41.25**	37.62
Market capitalization	**16,293,485**	14,096,299
Total capitalization	**18,370,563**	15,856,623
Net debt as a percentage of total capitalization	**11**	11
Annual funds flow from operations	**2,047,817**	1,601,850
Net debt to funds flow from operations (2)	**1.0**	1.1

(1) The shares outstanding balance at December 31, 2013 excludes 678,361 common shares issued on January 15, 2014 pursuant to the DRIP. The shares outstanding balance at December 31, 2012 excludes 1,638,734 issued on January 15, 2013 pursuant to the DRIP.

(2) The net debt reflects the financing of acquisitions, however, the funds flow from operations only reflects funds flow from operations generated from the acquired properties since the closing date of the acquisitions.

Net debt is calculated as long-term debt plus accounts payable and accrued liabilities and dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the equity settled component of dividends payable and unrealized foreign exchange on translation of US dollar senior guaranteed notes.

The Company has a syndicated unsecured credit facility with fourteen banks and an operating credit facility with one Canadian chartered bank totaling $2.1 billion. The syndicated unsecured credit facility also includes an accordion feature that allows the Company to increase the facility by up to $500.0 million. As at December 31, 2013, the Company had approximately $553.7 million drawn on bank credit facilities, including $3.9 million outstanding pursuant to letters of credit, leaving unutilized borrowing capacity of approximately $1.5 billion.

The Company has closed private offerings of senior guaranteed notes raising gross proceeds of US$983.0 million and Cdn$142.0 million. These notes rank *pari passu* with the Company's bank credit facilities and are unsecured with original terms of maturity from 5 to 10 years. Concurrent with the issuance of US$953.0 million senior guaranteed notes, the Company entered into CCIRS with a syndicate of financial institutions. Under the terms of the CCIRS, the amount of the US notes was fixed for purposes of interest and principal repayments at a notional amount of $953.2 million. Concurrent with the issuance of US$30.0 million senior guaranteed notes, the Company entered a cross currency principal swap which fixed the principal repayment at a notional amount of $32.2 million.

At December 31, 2013 and December 31, 2012, Crescent Point was capitalized with 89 percent equity. The Company's net debt to funds flow from operations ratio at December 31, 2013 was 1.0 times, compared to 1.1 times at December 31, 2012. This decrease is largely due to the increase in funds flow from operations. Crescent Point's target average net debt to 12 month funds flow is approximately 1.0 times.

The Company has a successful DRIP which raised $659.1 million during the year ended December 31, 2013 (year ended December 31, 2012 - $564.1 million).

Crescent Point's development capital budget for 2014 is $1.75 billion, with average 2014 production forecast at 126,500 boe/d.

Crescent Point's management believes that with the high quality reserve base and development inventory, excellent balance sheet and solid hedging program, the Company is well positioned to meet its planned growth and development targets to continue generating strong operating and financial results through 2014 and beyond.

Shareholders' Equity

At December 31, 2013, Crescent Point had 395.0 million common shares issued and outstanding compared to 374.7 million common shares at December 31, 2012. The increase of 20.3 million shares relates primarily to shares issued pursuant to the DRIP.

Crescent Point's total capitalization increased to $18.4 billion at December 31, 2013 compared to $15.9 billion at December 31, 2012, with the market value of the shares representing 89 percent of the total capitalization. The increase in total capitalization primarily relates to the increases in the Company's year-end share price, shares outstanding and net debt.

Subsequent Events

New York Stock Exchange ("NYSE") Listing

On January 22, 2014, Crescent Point's common shares began trading on the NYSE under the ticker symbol "CPG".

Contractual Obligations and Commitments

The Company has assumed various contractual obligations and commitments in the normal course of operations. At December 31, 2013, the Company had contractual obligations and commitments as follows:

($000s)	1 year	2 to 3 years	4 to 5 years	More than 5 years	Total
Operating leases (building and vehicle leases)[1]	18,343	48,242	48,241	281,817	396,643
Senior guaranteed notes[2]	56,108	242,717	210,337	969,357	1,478,519
Bank credit facilities[3]	-	546,595	-	-	546,595
Transportation commitments	1,705	461	144	13	2,323
Derivative contract premiums	15,697	-	-	-	15,697
Total	91,853	838,015	258,722	1,251,187	2,439,777

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

(2) These amounts include the effect of principal and interest payments pursuant to the CCIRS and cross currency principal swap.

(3) These amounts exclude interest payable on amounts drawn on the bank credit facilities.

Off Balance Sheet Arrangements

The Company has off-balance sheet financing arrangements consisting of various lease agreements which are entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease. No asset or liability value has been assigned to these leases in the balance sheet as of December 31, 2013. All of the lease agreement amounts have been reflected in the Contractual Obligations and Commitments table above.

Critical Accounting Estimates

The preparation of the Company’s consolidated financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision of these estimates over time. A summary of the significant accounting policies used by Crescent Point can be found in Note 3 of the December 31, 2013 audited consolidated financial statements. The following discussion outlines what management believes to be the most critical policies involving the use of estimates and assumptions.

Oil and gas activities

Reserves estimates, although not reported as part of the Company’s consolidated financial statements, can have a significant effect on net income, assets and liabilities as a result of their impact on depletion, depreciation and amortization, decommissioning liability, deferred taxes, asset impairments and business combinations. Independent petroleum reservoir engineers perform evaluations of the Company’s oil and gas reserves on an annual basis. The estimation of reserves is an inherently complex process requiring significant judgment. Estimates of economically recoverable oil and gas reserves are based upon a number of variables and assumptions such as geoscientific interpretation, production forecasts, commodity prices, costs and related future cash flows, all of which may vary considerably from actual results. These estimates are expected to be revised upward or downward over time, as additional information such as reservoir performance becomes available, or as economic conditions change.

For purposes of impairment testing, property, plant and equipment is aggregated into cash-generating units, based on separately identifiable and largely independent cash inflows. The determination of the Company’s CGUs is subject to judgment. Factors considered in the classification of CGUs include the integration between assets, shared infrastructures, the existence of common

sales points, geography, geologic structure and the manner in which management monitors and makes decisions regarding operations.

The determination of technical feasibility and commercial viability, based on the presence of reserves and which results in the transfer of assets from E&E to PP&E, is subject to judgment.

Decommissioning liability

Upon retirement of its oil and gas assets, the Company anticipates incurring substantial costs associated with decommissioning. Estimates of these costs are subject to uncertainty associated with the method, timing and extent of future decommissioning activities. The liability, the related asset and the expense are impacted by estimates with respect to the cost and timing of decommissioning.

Business combinations

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of PP&E and E&E assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices, and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net earnings can be affected as a result of changes in future DD&A, asset impairment or goodwill impairment.

Fair value measurement

The estimated fair value of derivative instruments resulting in derivative assets and liabilities, by their very nature, are subject to measurement uncertainty. Estimates included in the determination of the fair value of derivative instruments include forward benchmark prices, discount rates and forward foreign exchange rates.

Joint control

Judgment is required to determine when the Company has joint control over an arrangement, which requires an assessment of the capital and operating activities of the projects it undertakes with partners and when the decisions in relation to those activities require unanimous consent.

Share-based compensation

Compensation costs recorded pursuant to share-based compensation plans are subject to estimated fair values, forfeiture rates and the future attainment of performance criteria.

Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. In addition, deferred income tax liabilities recognize the extent that temporary differences will be payable in future periods. The calculation of the liability involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable earnings, the availability of cash flows and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

Risk Factors

Financial Risk

Financial risk is the risk of loss or lost opportunity resulting from financial management and market conditions that could have a positive or negative impact on Crescent Point's business. Financial risks the Company is exposed to include: marketing reserves at an acceptable price given market conditions; finding and producing reserves at a reasonable cost; volatility in market prices for oil and natural gas; fluctuations in foreign exchange and interest rates; stock market volatility; debt service which may limit timing or amount of dividends as well as market price of shares; the continued availability of adequate debt and equity financing and cash flow to fund planned expenditures; sufficient liquidity for future operations; lost revenue or increased expenditures as a result of delayed or denied environmental, safety or regulatory approvals; cost of capital risk to carry out the Company's operations; and uncertainties associated with credit facilities and counterparty credit risk.

Operational Risk

Operational risk is the risk of loss or lost opportunity resulting from operating and capital activities that, by their nature, could have an impact on the Company's ability to achieve objectives. Operational risks Crescent Point is exposed to include: uncertainties associated with estimating oil and natural gas reserves; incorrect assessments of the value of acquisitions and exploration and development programs; failure to realize the anticipated benefits of acquisitions; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; inability to secure adequate product transportation including sufficient crude-by-rail or other alternate transportation; delays in business operations, pipeline restrictions, blowouts; unforeseen title defects; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; loss of key personnel; unexpected geological, technical, drilling, construction and processing problems; availability of insurance; competitive action by other companies; the ability of suppliers to meet commitments and risks; and uncertainties related to oil and gas interests and operations on tribal lands.

Safety, Environmental and Regulatory Risks

Safety, environmental and regulatory risks are the risks of loss or lost opportunity resulting from changes to laws governing safety, the environment, royalties and taxation. Safety, environmental and regulatory risks Crescent Point is exposed to include: aboriginal land claims; uncertainties associated with regulatory approvals; uncertainty of government policy changes; the risk of carrying out operations with minimal environmental impact; changes in or adoption of new laws and regulations or changes in how they are interpreted or enforced; obtaining required approvals of regulatory authorities and stakeholder support for activities and growth plans.

There are no new material environmental initiatives impacting Crescent Point at this time.

Risk Management

Crescent Point is committed to identifying and managing these risks in the near term, as well as on a strategic and longer term basis at all levels in the organization in accordance with our Board-approved Risk Management and Counterparty Credit Policy and risk management programs. Issues affecting, or with the potential to affect, our assets, operations and/or reputation, are generally of a strategic nature or are emerging issues that can be identified early and then managed, but occasionally include unforeseen issues that arise unexpectedly and must be managed on an urgent basis. Crescent Point takes a proactive approach to the identification and management of issues that can affect the Company's assets, operations and/or reputation and have established consistent and clear policies, procedures, guidelines and responsibilities for issue identification and management.

Specific actions Crescent Point takes to ensure effective risk management include: employing qualified professional and technical staff; concentrating in a limited number of areas with low cost exploitation and development objectives; utilizing the latest technology for finding and developing reserves; constructing quality, environmentally sensitive and safe production facilities; adopting and communicating sound policies governing all areas of our business; maximizing operational control of drilling and production operations; strategic hedging of commodity prices, interest and foreign exchange rates; adhering to conservative borrowing guidelines; monitoring counterparty creditworthiness and obtaining counterparty credit insurance.

Changes in Accounting Policies

Effective January 1, 2013, the Company adopted the following IFRS:

- IFRS 7 *Financial Instruments: Disclosures* - IFRS 7 was amended to provide more extensive quantitative disclosures for financial instruments that are offset in the statement of financial position or that are subject to enforceable master netting or similar agreements. The additional disclosures can be found in Note 22 of the annual consolidated financial statements for the year ended December 31, 2013. The application of the amendment had no impact on the consolidated statements of comprehensive income or the consolidated balance sheets.

- IFRS 9 *Financial Instruments* - IFRS 9 was amended to present a new hedge accounting model. The Company does not currently apply hedge accounting and determined that the amendment to IFRS 9 had no impact on the consolidated statements of comprehensive income or the consolidated balance sheet.

- IFRS 10 *Consolidated Financial Statements* - IFRS 10 provides guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The Company reviewed its consolidation methodology and determined that the adoption of IFRS 10 did not result in a change to the consolidation status of its subsidiaries.

- IFRS 11 *Joint Arrangements* - IFRS 11 presents a new model for determining whether an entity should account for joint arrangements using proportionate consolidation or the equity method. An entity will have to follow the substance rather than legal form of a joint arrangement and will no longer have a choice of accounting method. The Company reviewed its joint arrangements and determined that the adoption of IFRS 11 did not result in any changes in the accounting for its joint arrangements. The Company's share of the assets, liabilities, revenues and expenses are recognized in the annual consolidated financial statements.

- IFRS 12 *Disclosure of Interests in Other Entities*- IFRS 12 aggregates and amends disclosure requirements included within other standards. The standard requires an entity to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The application of IFRS 12 had no impact on the consolidated statements of comprehensive income or the consolidated balance sheets.

- IFRS 13 *Fair Value Measurement* - IFRS 13 provides a single framework for measuring fair value. The measurement of the fair value of an asset or liability is based on assumptions that market participants would use when pricing the asset or liability under current market conditions, including assumptions about risk. The Company adopted IFRS 13 on January 1, 2013 on a prospective basis. The adoption of IFRS 13 did not require any adjustments to the valuation techniques used by the Company to measure fair value and did not result in any measurement adjustments as at January 1, 2013.

Future Changes in Accounting Policies

IAS 36 Impairment of Assets - IAS 36 was amended in May 2013 to reduce the circumstances in which the recoverable amount of CGUs is required to be disclosed and clarify the disclosures required when an impairment loss has been recognized or reversed in the period. The amendments require retrospective application and will be adopted by the Company on January 1, 2014. The adoption will only impact Crescent Point's disclosures in the notes to the financial statements in periods when an impairment loss or impairment recovery is recognized.

Outstanding Common Shares Data

As of the date of this report, the Company had 397,249,891 common shares outstanding.

Selected Annual Information

($000s, except per share amounts)	**2013**	2012	2011
Total oil and gas sales	**3,526,448**	2,694,994	2,191,189
Average daily production			
Crude oil and NGLs (bbls/d)	**109,129**	89,704	66,604
Natural gas (mcf/d)	**66,952**	54,284	43,172
Total (boe/d)	**120,288**	98,751	73,799
Net income [(1)]	**144,876**	190,653	201,134
Net income per share [(1)]	**0.38**	0.58	0.73
Net income per share - diluted [(1)]	**0.37**	0.57	0.72
Operating income	**485,688**	303,568	375,500
Operating income per share	**1.26**	0.92	1.36
Operating income per share – diluted	**1.25**	0.91	1.35
Cash flow from operating activities	**1,973,332**	1,543,943	1,322,971
Cash flow from operating activities per share	**5.11**	4.69	4.80
Cash flow from operating activities per share - diluted	**5.09**	4.65	4.76
Funds flow from operating activities	**2,047,817**	1,601,850	1,293,257
Funds flow from operating activities per share	**5.30**	4.86	4.70
Funds flow from operating activities per share - diluted	**5.28**	4.83	4.65
Working capital (deficit) [(2)]	**(406,134)**	(287,911)	(129,066)
Total assets	**12,736,793**	12,131,634	8,734,446
Total liabilities	**4,236,720**	3,536,822	2,918,030
Net debt	**2,077,078**	1,760,324	1,220,144
Total long-term derivative liabilities	**25,846**	8,483	64,220
Weighted average shares - diluted (thousands)	**387,731**	331,781	278,214
Dividends paid or declared	**1,081,551**	931,400	771,362
Dividends paid or declared per share	**2.76**	2.76	2.76

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

(2) Working capital deficiency is calculated as accounts payable and accrued liabilities plus dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the equity settled component of dividends payable.

Crescent Point's oil and gas sales, cash flow from operating activities, funds flow from operations and total assets have increased for the years 2011 through 2013 due to numerous corporate and property acquisitions and the Company's successful drilling program, which have resulted in higher production volumes. Net income over the past three years has fluctuated primarily due to unrealized derivative gains and losses on derivative contracts, which fluctuate with changes in market conditions, and impairments to PP&E recorded in 2012 and 2013, along with associated fluctuations in deferred income tax expense (recovery).

Operating income has fluctuated over the past three years primarily due to changes in funds flow from operations, depletion and share-based compensation expense and impairments to property, plant and equipment recorded in 2012 and 2013, along with associated fluctuations in the deferred tax expense (recovery).

Summary of Quarterly Results

	2013				2012			
($000s, except per share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and gas sales	**908,637**	980,829	845,270	791,712	727,372	658,204	642,857	666,561
Average daily production								
Crude oil and NGLs (bbls/d)	**115,971**	107,332	106,609	106,519	97,731	89,648	88,798	82,552
Natural gas (mcf/d)	**70,017**	63,785	67,142	66,865	61,654	59,896	49,046	46,395
Total (boe/d)	**127,641**	117,963	117,799	117,663	108,007	99,631	96,972	90,285
Net income (loss)	**(13,723)**	87,879	72,332	(1,612)	(95,241)	2,352	287,430	(3,888)
Net income (loss) per share	**(0.03)**	0.23	0.19	-	(0.26)	0.01	0.89	(0.01)
Net income (loss) per share – diluted	**(0.03)**	0.22	0.19	-	(0.26)	0.01	0.89	(0.01)
Operating income (loss)	**78,216**	162,819	130,308	114,345	(19,802)	89,158	135,009	99,203
Operating income (loss) per share	**0.20**	0.42	0.34	0.30	(0.05)	0.26	0.42	0.33
Operating income (loss) per share – diluted	**0.20**	0.42	0.34	0.30	(0.05)	0.26	0.42	0.33
Cash flow from operating activities	**508,090**	542,809	463,194	459,239	421,598	403,980	417,518	300,847
Cash flow from operating activities per share	**1.29**	1.39	1.21	1.21	1.17	1.19	1.30	1.02
Cash flow from operating activities per share – diluted	**1.29**	1.39	1.20	1.21	1.16	1.19	1.29	1.01
Funds flow from operations	**533,310**	554,144	504,420	455,943	430,386	384,237	386,318	400,909
Funds flow from operations per share	**1.35**	1.42	1.32	1.21	1.19	1.14	1.20	1.35
Funds flow from operations per share – diluted	**1.35**	1.42	1.31	1.20	1.18	1.13	1.19	1.34
Working capital (deficit) [(1)]	**(406,134)**	(318,224)	(227,620)	(312,777)	(287,911)	(153,348)	(73,457)	(152,674)
Total assets	**12,736,793**	12,526,359	12,357,474	12,425,234	12,131,634	11,256,848	11,306,482	10,428,957
Total liabilities	**4,236,720**	3,926,421	3,757,823	3,872,025	3,536,822	3,247,769	3,844,464	3,550,136
Net debt	**2,077,078**	1,887,431	1,825,340	1,957,964	1,760,324	1,453,647	2,003,711	1,572,330
Total long-term derivative liabilities	**25,846**	10,305	4,671	11,490	8,483	17,961	6,997	117,967
Weighted average shares – diluted (thousands)	**395,277**	390,607	385,084	379,647	363,358	340,483	323,782	298,666
Capital expenditures [(2)]	**510,889**	531,880	262,744	559,627	1,395,268	335,310	1,013,936	1,785,745
Dividends declared	**274,797**	271,855	267,033	267,866	255,621	240,010	225,212	210,557
Dividends declared per share	**0.69**	0.69	0.69	0.69	0.69	0.69	0.69	0.69

(1) Working capital deficiency is calculated as accounts payable and accrued liabilities plus dividends payable, less cash, accounts receivable, prepaids and deposits and long-term investments, excluding the equity settled component of dividends payable.

(2) Capital expenditures exclude capitalized share-based compensation and include capital acquisitions. Capital acquisitions represent total consideration for the transactions including long-term debt and working capital assumed, and excluding transaction costs.

Over the past eight quarters, the Company's oil and gas sales have generally increased due to a successful drilling program and several business combinations. Fluctuations in production, the Cdn$ WTI benchmark price and corporate oil price differentials have also contributed to the fluctuations in oil and gas sales.

Net income has fluctuated primarily due to changes in funds flow from operations, unrealized derivative gains and losses, which fluctuate with the changes in forward market prices and an impairment to property, plant and equipment recorded in the fourth quarters of 2012 and 2013, along with associated fluctuations in the deferred tax expense (recovery).

Operating income has fluctuated over the past eight quarters primarily due to changes in funds flow from operations, depletion and share-based compensation expense and impairments to property, plant and equipment recorded in the fourth quarters of 2012 and 2013, along with associated fluctuations in the deferred tax expense (recovery).

Capital expenditures fluctuated through this period as a result of timing of acquisitions and our development drilling program. Funds flow from operations and cash flow from operating activities throughout the last eight quarters has allowed the Company to maintain stable monthly dividends.

Fourth Quarter Review

- Crescent Point achieved a new production record in fourth quarter 2013 and averaged 127,641 boe/d, weighted 91 percent to light and medium crude oil and liquids. This represents a growth rate of 8 percent over third quarter 2013 and 18 percent over fourth quarter 2012.

- During the fourth quarter, the Company spent $389.4 million on drilling and development activities, drilling 205 (161.6 net) wells with a 99 percent success rate. Crescent Point also spent $96.1 million on land, seismic and facilities, for total capital expenditures of $485.5 million.

- Crescent Point generated funds flow from operations of $533.3 million ($1.35 per share - diluted) in fourth quarter 2013, representing a 24 percent increase over fourth quarter 2012 funds flow from operations of $430.4 million ($1.18 per share - diluted). Funds flow from operations was driven by strong operating netbacks prior to realized derivatives of $50.67 per boe.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109*Certification of Disclosure in Issuers' Annual and Interim Filings*, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim filings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be so disclosed is accumulated and communicated to management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and the Chief Financial Officer of Crescent Point evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that Crescent Point's DC&P were effective as at December 31, 2013.

Internal Controls over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that:

1. pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of assets of Crescent Point;

2. are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Crescent Point are being made in accordance with authorizations of management and Directors of Crescent Point; and

3. are designed to provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The Chief Executive Officer and the Chief Financial Officer are responsible for establishing and maintaining ICFR for Crescent Point. They have, as at the financial year ended December 31, 2013, designed ICFR, or caused it to be designed under their supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework Crescent Point's officers used to design the Company's ICFR is the *Internal Control-Integrated Framework* (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Under the supervision of the Chief Executive Officer and the Chief Financial Officer, Crescent Point conducted an evaluation of the effectiveness of the Company's ICFR as at December 31, 2013 based on the COSO Framework. Based on this evaluation, the officers concluded that as of December 31, 2013, Crescent Point maintained effective ICFR.

It should be noted that while Crescent Point's officers believe that the Company's controls provide a reasonable level of assurance with regard to their effectiveness, they do not expect that the DC&P and ICFR will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, but not absolute, assurance that the objectives of the control system are met.

There were no changes in Crescent Point's ICFR during the year ended December 31, 2013 that materially affected, or are reasonably likely to materially affect, the Company's ICFR.

Health, Safety and Environment Policy

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

- Complying with government regulations and standards;

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

- Ensuring prompt, effective response and repair to emergency situations and environmental incidents;

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

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

As part of Crescent Point's ongoing commitment to reduce greenhouse gas emissions, the Company contributes to a reclamation fund whereby $0.30 per produced boe is directed to environmental emissions reduction. To date, $44.6 million has been contributed to the environment emission reduction fund and $24.5 million has been expended to reduce greenhouse gas emissions and to meet and exceed provincial and federal targets. In 2013, the Company spent a total of $3.6 million primarily on the installation of flare equipment in Saskatchewan. The flare equipment reduces emissions to meet provincial and federal emission regulations.

Outlook

Crescent Point's revised guidance for 2014 is as follows:

Production	**Prior**	**Revised**
Oil and NGL (bbls/d)	115,000	115,000
Natural gas (mcf/d)	69,000	69,000
Total (boe/d)	126,500	126,500
Exit (boe/d)	135,000	135,000
Annualized fourth quarter funds flow from operations ($000) [(1)]	2,315,000	2,460,000
Funds flow from operations ($000)	2,100,000	2,250,000
Funds flow per share – diluted ($)	5.24	5.59
Cash dividends per share ($)	2.76	2.76
Capital expenditures [(2)]		
Drilling and completions ($000)	1,420,000	1,420,000
Facilities, land and seismic ($000)	330,000	330,000
Total ($000)	1,750,000	1,750,000
Pricing		
Crude oil – WTI (US$/bbl)	95.00	100.00
Crude oil – WTI (Cdn$/bbl)	101.06	111.11
Corporate oil differential (%)	14	13
Natural gas – AECO (Cdn$/mcf)	3.25	4.65
Exchange rate (US$/Cdn$)	0.94	0.90

(1) Annualized fourth quarter funds flow from operations is fourth quarter funds flow from operations multiplied by four.

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

Additional information relating to Crescent Point, including the Company's December 31, 2013 Annual Information Form, is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov/edgar.shtml.

Forward-Looking Information

Certain statements contained in this management's discussion and analysis constitute forward-looking statements and are based on Crescent Point's beliefs and assumptions based on information available at the time the assumption was made. By its nature, such forward-looking information involves known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements should not be unduly relied upon. These statements are effective only as of the date of this report.

Certain statements contained in this report, including statements related to Crescent Point's capital expenditures, projected asset growth, view and outlook toward future commodity prices, drilling activity and statements that contain words such as "could", "should", "can", "anticipate", "expect", "believe", "will", "may", “projected”, “sustain”, “continues”, “strategy”, “potential”, “projects”, “grow”, “take advantage”, “estimate”, “well positioned” and similar expressions and statements relating to matters that are not historical facts constitute "forward-looking information" within the meaning of applicable Canadian securities legislation. The material assumptions in making these forward-looking statements are disclosed in this analysis under the headings “Dividends”, “Capital Expenditures”, “Decommissioning Liability”, “Liquidity and Capital Resources”, “Critical Accounting Estimates”, “Changes in Accounting Policies”, “Future Changes in Accounting Policies” and “Outlook”.

In particular, forward-looking statements include, but are not limited to:

- Crescent Point’s 2014 guidance as outlined in the Outlook section and ability to meet planned growth and development targets;
- Maintaining monthly dividends;
- The anticipated impact of the use of financial commodity derivatives and fixed differential physical contracts on the stability of cashflows;
- Anticipated future operating, abandonment and decommissioning costs;
- Expected oil price differentials in 2014;
- Estimated future usable tax pools and anticipated taxability; and
- Target average net debt to 12 month funds flow of approximately 1.0 times.

All of the material assumptions underlying these statements are noted in the “Dividends”, “Capital Expenditures”, Decommissioning Liability”, “Liquidity and Capital Resources”, “Critical Accounting Estimates” and “Outlook” sections of this report.

The following are examples of references to forward-looking information:

- Volume and product mix of Crescent Point's oil and gas production;
- Future oil and gas prices in respect of Crescent Point's commodity risk management programs;
- The amount and timing of future decommissioning liabilities;
- Future liquidity and financial capacity;
- Future interest rates and exchange rates;
- Future results from operations and operating metrics;
- Future development, exploration and other expenditures;
- Future costs, expenses and royalty rates;
- Future tax rates; and
- The Company's tax pools.

This information contains certain forward-looking estimates that involve substantial known and unknown risks and uncertainties, certain of which are beyond Crescent Point's control. Such risks and uncertainties include, but are not limited to: financial risk of marketing reserves at an acceptable price given market conditions; volatility in market prices for oil and natural gas; delays in business operations, pipeline restrictions, blowouts; the risk of carrying out operations with minimal environmental impact; industry conditions including changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; uncertainties associated with estimating oil and natural gas reserves; risks and uncertainties related to oil and gas interests and operations on tribal lands; economic risk of finding and producing reserves at a reasonable cost; uncertainties associated with partner plans and approvals; operational matters related to non-operated properties; increased competition for, among other things, capital, acquisitions of reserves and undeveloped lands; competition for and availability of qualified personnel or management; incorrect assessments of the value of acquisitions and exploration and development programs; unexpected geological, technical, drilling, construction, processing and transportation problems; availability of insurance; fluctuations in foreign exchange and interest rates; stock market volatility; general economic, market and business conditions; uncertainties associated with regulatory approvals; uncertainty of government policy changes; uncertainties associated with credit facilities and counterparty credit risk; changes in income tax laws, tax laws, crown royalty rates and incentive programs relating to the oil and gas industry; and other factors, many of which are outside the control of the Company. Therefore, Crescent Point's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking estimates and if such actual results, performance or achievements transpire or occur, or if any of them do so, there can be no certainty as to what benefits 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.

Directors

Peter Bannister, Chairman [1] [3] [4]

Ken Cugnet [3] [4] [5]

Hugh Gillard [1] [2] [5]

Gerald Romanzin [1] [2] [3]

Scott Saxberg [4]

Greg Turnbull [2] [5]

[1] Member of the Audit Committee of the Board of Directors

[2] Member of the Compensation Committee of the Board of Directors

[3] Member of the Reserves Committee of the Board of Directors

[4] Member of the Health, Safety and Environment Committee of the Board of Directors

[5] Member of the Corporate Governance and Nominating Committee

Officers

Scott Saxberg
President and Chief Executive Officer

Greg Tisdale
Chief Financial Officer

C. Neil Smith
Chief Operating Officer

Brad Borggard
Vice President, Corporate Planning

Derek Christie
Vice President, Exploration and Geosciences

Ryan Gritzfeldt
Vice President, Engineering East

Ken Lamont
Vice President, Finance and Treasurer

Tamara MacDonald
Vice President, Land

Trent Stangl
Vice President, Marketing and Investor Relations

Steve Toews
Vice President, Engineering West

Mark Eade
Corporate Secretary

Head Office

Suite 2800, 111 - 5th Avenue S.W.
Calgary, Alberta T2P 3Y6
Tel: (403) 693-0020
Fax: (403) 693-0070
Toll Free: (888) 693-0020

Banker

The Bank of Nova Scotia
Calgary, Alberta

Auditor

PricewaterhouseCoopers LLP
Calgary, Alberta

Legal Counsel

Norton Rose Fulbright Canada LLP
Calgary, Alberta

Evaluation Engineers

GLJ Petroleum Consultants Ltd.
Calgary, Alberta

Sproule Associates Ltd.
Calgary, Alberta

Registrar and Transfer Agent

Investors are encouraged to contact Crescent Point's Registrar and Transfer Agent for information regarding their security holdings:

Olympia Trust Company
2300, 125 - 9th Avenue S.E.
Calgary, Alberta T2G 0P6
Tel: (403) 261-0900

Stock Exchanges

Toronto Stock Exchange - TSX
New York Stock Exchange - NYSE

Stock Symbol

CPG

Investor Contacts

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President and Chief Executive Officer
(403) 693-0020

Greg Tisdale
Chief Financial Officer
(403) 693-0020

Trent Stangl
Vice President, Marketing and Investor Relations
(403) 693-0020

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Scott Saxberg, certify that:

1. I have reviewed this annual report of Crescent Point Energy Corp. on Form 40-F;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the period presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 12, 2014 CRESCENT POINT ENERGY CORP.

/s/ Scott Saxberg _____
Name: Scott Saxberg
Title: President and Chief Executive Officer

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Gregory T. Tisdale, certify that:

1. I have reviewed this annual report of Crescent Point Energy Corp. on Form 40-F;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the period presented in this report;

4. The issuer's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Dated: March 12, 2014 CRESCENT POINT ENERGY CORP.

/s/ Gregory T. Tisdale_____
Name: Gregory T. Tisdale
Title: Chief Financial Officer

Exhibit 99.6

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Crescent Point Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Scott Saxberg, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 12, 2014 CRESCENT POINT ENERGY CORP.

/s/ Scott Saxberg
Name: Scott Saxberg
Title: President and Chief Executive Officer

Exhibit 99.7

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Annual Report of Crescent Point Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2013, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Gregory T. Tisdale, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: March 12, 2014 CRESCENT POINT ENERGY CORP.

/s/ Gregory T. Tisdale_____
Name: Gregory T. Tisdale
Title: Chief Financial Officer

Exhibit 99.8



March 12, 2014

Consent of Independent Auditor

We hereby consent to the incorporation by reference in this Annual Report on Form 40-F for the year ended December 31, 2013 of Crescent Point Energy Corp. of our report dated March 11, 2014, relating to the consolidated financial statements, which comprise the consolidated balance sheet as at December 31, 2013 and December 31, 2012 and the consolidated statements of comprehensive income, changes in shareholders' equity and cash flows for the years ended December 31, 2013 and December 31, 2012, which appear in the Exhibit incorporated by reference in this Annual Report. We also consent to reference to us under the heading "Interests of Experts", which appears in the Annual Information Form included in the Exhibit incorporated by reference in this Annual Report on Form 40-F.

PricewaterhouseCoopers LLP

Chartered Accountants

PricewaterhouseCoopers LLP
111 5 Avenue SW, Suite 3100, Calgary, Alberta, Canada T2P 5L3
T: +1 403 509 7500, F: +1 403 781 1825, www.pwc.com/ca

"PwC" refers to PricewaterhouseCoopers LLP, an Ontario limited liability partnership, which is a member firm of PricewaterhouseCoopers International Limited, each member firm of which is a separate legal entity.

Exhibit 99.9

GLJ Petroleum Consultants

Principal Officers:

Keith M. Braaten, P. Eng.
President & CEO
Jodi L. Anhorn, M.Sc., P. Eng.
Executive Vice President & COO

Officers / Vice Presidents:

Terry L. Aarsby, P. Eng.
Caralyn P. Bennett, P. Eng.
Leonard L. Herchen, P. Eng.
Myron J. Hladyshevsky, P. Eng.
Todd J. Ikeda, P. Eng.
Bryan M. Joa, P. Eng.
Mark Jobin, P. Geol.
John E. Keith, P. Eng.
John H. Stilling, P. Eng.
Douglas R. Sutton, P. Eng.
James H. Willmon, P. Eng.

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated March 11, 2014 and effective December 31, 2013, evaluating the petroleum and natural gas reserves attributable to Crescent Point Energy Corp. and its affiliates, which is entitled "Reserves Assessment and Evaluation of Canadian and American Oil and Gas Properties (the "Report").

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

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2013 dated March 11, 2014, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Yours truly,

GLJ PETROLEUM CONSULTANTS LTD.

Terry L. Aarsby, P. Eng.
Vice President

Dated: March 11, 2014
Calgary, Alberta
CANADA

Exhibit 99.10

R.K. MacLeod*, B.S., P.Eng., *CEO and Board Chairman*
H.J. Helwerda*, B.Sc., P.Eng., FEC, *President* & COO
D.J. Carsted*, CD, B.Sc., P.Geol., *Executive VP* & *CTO*
G.D. Robinson*, B.Sc., P.Eng., *VP, International*
C.P. Six*, B.Sc., P.Eng., *VP, Unconventional*
A.A. Szabo*, B.Sc., P.Eng., *Manager, Engineering*
S.W. Pennell*, B.S., P.Eng., *Manager, Engineering, International*
B.F. Jose, M.Sc., P.Geoph., *VP, Geoscience, International*
N.T. Stewart, B.A.Sc., P.Eng., *VP, Engineering, Canada*
K.P. McDonald, B.Comm., CA, *CFO*
M.R. Van de Veen, QC, J.D., M.B.A., L.L.M., *General Counsel, Corporate Secretary*

**Directors*

Ref.: 3075

March 10, 2014

Re: Consent of Independent Engineers

We refer to our report dated February 5, 2014 and effective December 31, 2013, evaluating the petroleum and natural gas reserves attributable to Crescent Point Energy Corp. and its affiliates, which is entitled "Evaluation of Certain Saskatchewan P&NG Reserves of Crescent Point Energy Corp. (As of December 31, 2013)" (the "Report").

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

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2013 dated March 11, 2014, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we performed in connection with such Report.

Sincerely,

SPROUIE ASSOCIATES LIMITED



Vincent K. Hui, P.Eng.
Petroleum Engineer and Partner