CRESCENT POINT ENERGY CORP.

RENEWAL ANNUAL INFORMATION FORM

For the Year Ended December 31, 2010

Dated March 24, 2011

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NOTE REGARDING FORWARD-LOOKING STATEMENTS

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 "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" 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.

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

- anticipated financial performance;
- business prospects;
- oil and natural gas production levels;
- capital expenditure programs;
- the quantity of the oil and natural gas reserves;
- projections of commodity prices and costs;
- payment of monthly dividends;
- supply and demand for oil and natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes.

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 "*Cash Dividends*", "*Capital Expenditures*", "*Asset Retirement Obligation*", "*Liquidity and Capital Resources*", "*Forward Looking Information*", "*Critical Accounting Estimates*" 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 the impact of general economic conditions; industry conditions including changes to laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; increased competition and the lack of availability of qualified personnel or management; fluctuations in commodity prices, foreign exchange or interest rates; stock market volatility and obtaining required approvals of regulatory authorities. In addition, there are numerous risks and uncertainties associated with oil and gas operations and the evaluation of oil and gas reserves. 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.

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.

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 24, 2011 for the year ended December 31, 2010.

"**Arrangement**" means the plan of arrangement involving the Trust, Crescent Point Energy Ltd., Tappit Resources Ltd., StarPoint Energy Ltd. and Crescent Point Acquisition Ltd. made effective September 5, 2003.

"**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.

"**CPC Trust**" means Crescent Point Commercial Trust, a wholly-owned subsidiary of the Trust settled under the laws of the Province of Alberta that was dissolved pursuant to the Conversion Arrangement.

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

"**CPGPC**" means Crescent Point General Partner Corp., a corporation amalgamated under the ABCA that was dissolved pursuant to the Conversion Arrangement.

"**CPHI**" means Crescent Point Holdings Inc., a corporation incorporated under the ABCA.

"**CPRI**" means Crescent Point Resources Inc., a corporation incorporated under the ABCA that was dissolved pursuant to the Conversion Arrangement.

"**CPRL**" means Crescent Point Resources Ltd., a predecessor corporation to CPGPC.

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

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

"**Gibraltar Arrangement**" means the plan of arrangement effected on July 3, 2009 under section 193 of the ABCA pursuant to which the Corporation acquired Gibraltar Exploration Ltd., as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2009*".

"**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).

"**Landex**" means Landex Petroleum Corp.

"**Landex Arrangement**" means the plan of arrangement involving the Trust and Landex completed on March 26, 2008, as more particularly described under the heading "*General Development of the Business of the Corporation – History - 2008*".

"**Limited Partnership**" means Crescent Point Resources Limited Partnership, a limited partnership formed under the laws of the Province of Alberta, having CPGPC as the general partner and the Trust and CPC Trust as limited partners, which was dissolved pursuant to the Conversion Arrangement.

"**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, 2010.

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

"**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.

"**Pilot**" means Pilot Energy Ltd.

"**Pilot Arrangement**" means the plan of arrangement involving Pilot, the Trust and CPGPC completed on January 16, 2008, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2008*".

"**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.

"**Ryland Oil**" means Ryland Oil Corporation.

"**Ryland Oil Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving the Corporation, the Partnership, Ryland Oil, Ryland Oil ULC, Pebble Petroleum Inc. and the Ryland Oil shareholders completed on August 20, 2010, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2010*".

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

"**Shelter Bay**" means Shelter Bay Energy Inc., a corporation incorporated pursuant to the ABCA.

"**Shelter Bay Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving the Corporation and Shelter Bay completed on July 2, 2010, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2010*".

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

"**TriAxon**" means TriAxon Resources Ltd.

"**TriAxon Arrangement**" means the plan of arrangement under Section 92 of the *Canada Business Corporations Act* involving the Corporation, TriAxon and 7277083 Canada Inc. completed on December 15, 2009, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2009*".

"**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.

"**Villanova**" means Villanova Energy Corporation.

"**Villanova Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving Villanova Energy Corporation, the Trust and CPGPC completed on January 15, 2009, as more particularly described under the heading *"General Development of the Business of the Corporation – History – 2009"*.

"**Wave**" means Wave Energy Ltd.

"**Wave Arrangement**" means the plan of arrangement under Section 193 of the ABCA involving Wave and the Corporation completed on October 22, 2009, as more particularly described under the heading "*General Development of the Business of the Corporation – History – 2009*".

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

SELECTED ABBREVIATIONS

In this annual information form, the abbreviations set forth below have the following meanings:

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

Other

API	American Petroleum Institute
API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil
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^3/d	cubic metres per day
Mboe	thousand barrels of oil equivalent
MMboe	Million barrels of oil equivalent
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

CURRENCY OF INFORMATION

The information set out in this renewal AIF is stated as at December 31, 2010 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. See "*General Development of the Business of the Corporation – 2009*".

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 3300, 421 – 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

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. 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 sources of cash flow are 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. The Partnership holds the Corporation's material operating assets, from which we generate cash flow.

CPHI

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

CPUSH

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

CPEUS

Crescent Point Energy U.S. Corp. is a wholly-owned indirect subsidiary of the Corporation.

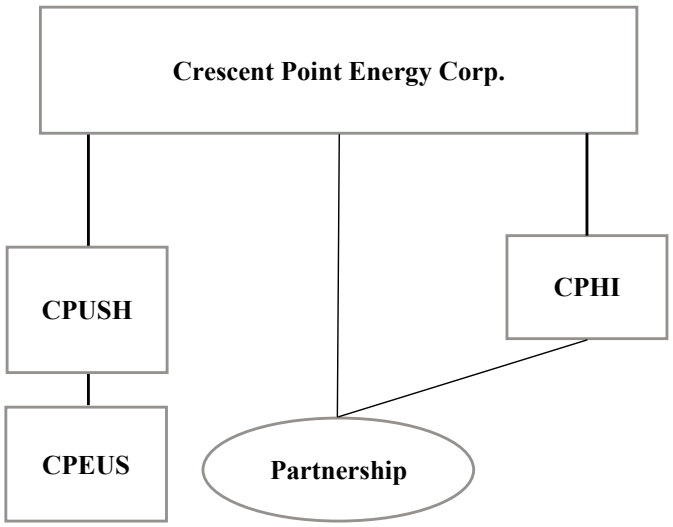
Relationships

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

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 24, 2011. Reference should be made to the appropriate sections of this AIF for a complete description of the structure of the Corporation.



Note:
(1) Crescent Point Resources Partnership is an Alberta general partnership which holds the majority of the oil and natural gas assets of the Corporation and CPHI.

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.

2008

On January 8, 2008, the Trust completed an equity offering of 5,155,000 Trust Units at $24.25 per Trust Unit for aggregate gross proceeds of $125 million.

On January 16, 2008, the Trust completed the Pilot Arrangement, through its wholly-owned subsidiary CPGPC, for total consideration of approximately $78.5 million paid through the issuance of 0.1284 of a Trust Unit for each issued and outstanding Pilot common share. See "*Description of Our Business - Reorganizations*".

On March 26, 2008, the Trust announced the completion of a $120 million commitment to Shelter Bay, a private Bakken light oil growth company, in association with Shelter Bay's closing of a $625 million private placement. The Trust also announced the related closing of the Landex Arrangement, pursuant to which Shelter Bay acquired Landex in exchange for total consideration of approximately $310 million, including approximately $75 million in Trust Units. Following the closing of the Landex Arrangement, the Trust acquired Landex's non-Bakken assets from Shelter Bay for $80 million. Crescent Point, through the Shelter Bay Unanimous Shareholders' Agreement had the right to 50% of

Shelter Bay's returns above a minimum threshold. Crescent Point also had certain contingent rights to acquire the shares of Shelter Bay, or Shelter Bay's assets, before March 31, 2013 and certain other shareholders of Shelter Bay had the right to sell their interests in Shelter Bay to Crescent Point from April 1, 2013 to September 30, 2013.

On April 11, 2008, the Trust announced it acquired ownership of 21.2% of the issued and outstanding Class A shares of Painted Pony. The Class A shares were acquired in connection with the sale by the Trust to Painted Pony of certain natural gas properties in the Cameron River/Blair fairway in northeast British Columbia.

On May 26, 2008, the Trust increased the amount available under the combined credit facilities by $200 million to $1 billion.

On August 6, 2008, the Trust announced that it closed the sale of its 21.2% interest in the Class A shares of Painted Pony Petroleum Ltd. to Shelter Bay by way of private sale. The aggregate cash consideration was approximately $18 million, which reflects the original cost of acquiring the shares plus accrued interest.

On October 1, 2008, the Trust and Shelter Bay announced the closing of a $300 million private placement financing for Shelter Bay. Shelter Bay raised total proceeds of $300 million through a private placement to existing Shelter Bay shareholders at a price of $1.50 per share. The Trust's share of the private placement was $78.7 million which was financed through the Trust's existing credit facilities. With the closing of the private placement, Crescent Point's aggregate investment in Shelter Bay was approximately $200 million which equated to a 21 percent interest in Shelter Bay. See "*Interest of Management and Others in Material Transactions*".

On October 16, 2008, the Trust increased the amount available under the combined credit facilities by $150 million to $1.15 billion.

On December 15, 2008, the Trust announced that it had acquired a 17 percent ownership of Wild River for $20 million.

On December 31, 2008, the Trust reinstated its DRIP since suspending it on December 11, 2007.

2009

On January 9, 2009, the Trust announced the closing of its equity offering of 5,227,325 Trust Units at $22.00 per Trust Unit for aggregate gross proceeds of $115 million.

On January 15, 2009, the Trust closed the Villanova Arrangement for total consideration of approximately $134.7 million, comprised of 4,625,294 Trust Units and assumed debt. See "*Description of Our Business – Reorganizations*".

On March 24, 2009, the Trust announced the closing of its equity offering of 10,825,000 Trust Units at $21.25 per Trust Unit for aggregate gross proceeds of approximately $230 million.

On June 1, 2009, the Trust closed the acquisition of assets in southeast Saskatchewan and Montana from Talisman Energy Canada for aggregate consideration of approximately $362.9 million.

On June 1, 2009, the Trust increased the amount available under the combined credit facilities by $50 million to $1.2 billion.

On June 15, 2009, the Trust suspended its DRIP to facilitate the Trust's conversion to a dividend paying corporation.

On July 2, 2009, the Wild River, the Trust, CPGPC and certain other parties completed the Conversion Arrangement for total consideration of 4,363,316 shares. Pursuant to the Conversion Arrangement, the Corporation acquired all of the issued and outstanding Trust Units. Holders of Trust Units received, for each Trust Unit held, one Common Share of the Corporation. In addition, the Trust was liquidated and dissolved and the Corporation received all of the assets and assumed all of the liabilities of the Trust. In connection with the Conversion Arrangement, the Corporation adopted a new restricted share bonus plan under which all restricted units previously issued under the Trust's existing restricted unit bonus plan were amended and restated such that the holders thereof have, upon vesting, the right to acquire Common Shares instead of Trust Units, on a one-for-one basis and on substantially the same terms, under the restricted share bonus plan. Pursuant to the Conversion Arrangement, the Trust also assigned its DRIP and all associated agreements to the Corporation, and the Corporation subsequently amended and restated them so that, among other things, all participants in the DRIP were deemed to be participants in the amended and restated DRIP without any further action on their part and the holders of Common Shares were able to participate in the amended and restated DRIP with respect to any cash dividends declared and paid by the Corporation on the Common Shares. In connection with the Conversion Arrangement, the Corporation also changed its name to Crescent Point Energy Corp. Additional information relating to the Conversion Arrangement is contained in the Information Circular. See "*Description of Our Business – Reorganizations*".

On July 3, 2009, the Corporation closed the Gibraltar Arrangement for total consideration of approximately $200.5 million, comprised of 4,112,272 Common Shares and assumed debt. See "*Description of Our Business – Reorganizations*".

On July 3, 2009, the Corporation completed the sale of 25% of the assets owned by the Corporation prior to the completion of the Conversion Arrangement and Gibraltar Exploration Ltd. to Shelter Bay for cash consideration of $81.9 million.

On July 15, 2009, the Corporation announced the reinstatement of its amended and restated DRIP for shareholders on record as of July 31, 2009. See "Dividends" for a description of the new Dividend and Dividend Reinvestment Plan.

On July 7, 2009 and September 30, 2009, the Corporation completed the acquisition of approximately 1,000 Boe/d of high quality, long life natural gas production in southwest Saskatchewan and approximately 2,750 Boe/d of high quality, long life crude oil in southeast Saskatchewan for cash consideration of $258.9 million.

On September 15, 2009, the Corporation completed an equity offering of 6,670,000 Common Shares at $34.50 per Common Share for aggregate gross proceeds of approximately $230 million.

On October 2, 2009, the Corporation purchased an aggregate of 32,166,667 shares of Reliable Energy Ltd. ("**Reliabl**e"), by way of a private placement, for the aggregate purchase price of $4,825,000, which shares represented 19.9% of the issued and outstanding shares of Reliable.

On October 22, 2009, the Corporation closed the Wave Arrangement for a total consideration of approximately $706.0 million, comprised of 17,497,643 Common Shares and assumed debt. See "*Description of Our Business – Reorganizations*".

On October 26, 2009, the Corporation purchased 5,333,333 shares in a private oil and gas company for $8,000,000, which represented approximately 20% of their issued and outstanding shares.

On November 3, 2009, the Corporation announced the closing of its equity offering of 15,444,500 Common Shares at $37.25 per Common Share for aggregate gross proceeds of $575.3 million.

On December 11, 2009, the Corporation increased the amount available under the combined credit facilities by $400 million to $1.6 billion. In addition, the terms of the credit facility were changed from secured to unsecured.

On December 15, 2009, the Corporation closed the TriAxon Arrangement for total consideration of approximately $254.9 million, comprised of 6,276,775 million Common Shares and assumed debt. See "*Description of Our Business – Reorganizations*".

2010

On January 15, 2010, the Corporation closed the acquisition of certain assets in southwest Saskatchewan from Penn West Energy Trust. The consideration was comprised of Crescent Point's 100 percent working interest in the Pembina Cardium play which was acquired pursuant to the TriAxon Arrangement, a 50 percent working interest in Crescent Point's Dodsland Viking play and $434 million cash.

On March 24, 2010, 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 U.S. $260 million and $50 million. The U.S. notes range from 5 to 10 years with a weighted average term of 8.5 years and coupon rates ranging from 4.71% to 6.03% and Canadian notes are a term of 5 years with a coupon of 4.92%.

On June 2, 2010, the Corporation announced the closing of its equity offering of 9,150,000 Common Shares at $41.00 per Common Share for aggregate gross proceeds of approximately $375.2 million.

On July 2, 2010, the Corporation closed the Shelter Bay Arrangement for total consideration of approximately $1.2 billion, comprised of 24,397,586 Common Shares and assumed debt. In respect of the Shelter Bay Arrangement, the Corporation has filed a Form 51-102F4 – *Business Acquisition Report*. See "*Description of Our Business – Reorganizations*".

On July 2, 2010, the Corporation announced it had acquired ownership of 13.3% of the issued and outstanding Class A shares of Painted Pony. The Class A shares were acquired pursuant to the Shelter Bay Arrangement.

On July 5, 2010, the Corporation closed a plan of arrangement under Section 193 of the ABCA with a private company for total consideration of approximately $95.6 million, comprised of 740,537 Common Shares and assumed debt. See "*Description of Our Business – Reorganizations*".

On August 6, 2010, the Corporation disposed of all its interest in 5,333,333 shares of a private oil and gas company.

On August 20, 2010, the Corporation closed the Ryland Oil Arrangement for total consideration of approximately $116.3 million, comprised of 2,178,719 Common Shares and assumed debt. See "*Description of Our Business – Reorganizations*".

On October 13, 2010, the Corporation announced the closing of its equity offering of 10,250,000 Common Shares at $36.60 per Common Share for aggregate gross proceeds of approximately $375.2 million.

On November 5, 2010, the Corporation completed the acquisition of approximately 950 Boe/d of high-quality, low-decline production in southeast Saskatchewan for cash consideration of $87.3 million.

2011

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

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. 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 and units in the Partnership. In addition, we continually review and assess numerous corporate and asset acquisition opportunities as part of our ongoing acquisition program.

The crude oil and natural gas properties and related assets generating income for the benefit of the Corporation are located in the provinces of Alberta, Saskatchewan, British Columbia and Manitoba and the states of Montana and North Dakota. The properties and assets consist of producing crude oil and natural gas reserves and proved plus probable 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 oil and natural gas properties.

We continually investigate and search out producing properties including those with large resource potential that 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, multi-zone potential and year round access. Our goal is to acquire operational control of those 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 water flood 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;

(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% of our existing production, after crown royalties, on a rolling three and a half year basis, at the discretion of management. All hedging activities are governed by our Risk Management Policy and are regularly reviewed by the board of directors of the Corporation.

As part of our risk management strategy in 2010, total oil and gas hedged was approximately 51% of annual production, net of royalties, of which approximately 54% of annual crude oil production and approximately 26% of annual natural gas production was hedged, net of royalties. The hedging strategies we utilized included only financial instruments, with our primary objective being to enhance the stability of cash dividends. The following table summarizes our commitments under all hedging agreements as at March 10, 2011.

Financial WTI Crude Oil Contracts – Canadian Dollar

Term	Volume (bbls/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)
2011 Weighted Average	30,958	82.13	101.90	82.75	89.83	(8.57)
2012 Weighted Average	25,500	88.53	98.97	82.15	92.91	(7.81)
2013 Weighted Average	20,750	91.76	100.86	84.33	-	-
January to June 2014 Weighted Average	11,249	95.89	105.74	86.00	-	-

Financial AECO Natural Gas Contracts – Canadian Dollar

Term	Volume (GJ/d)	Average Swap Price ($Cdn/GJ)
2011 Weighted Average	9,000	5.96
2012 Weighted Average	8,000	5.90
January to March, 2013 Weighted Average	3,000	5.27

Financial Interest Rate Contracts – Canadian Dollar

Term	Contract	Principal ($Cdn)	Fixed Annual Rate (%)
January 2011 to June 2011	Swap	75,000,000	3.89
January 2011 to May 2015	Swap	25,000,000	2.90
January 2011 to May 2015	Swap	25,000,000	3.50
January 2011 to May 2015	Swap	50,000,000	3.09
January 2011 to July 2015	Swap	50,000,000	3.63
July 2011 to June 2015	Swap	50,000,000	3.78

Financial Cross Currency Interest Rate Derivative Contracts – Canadian Dollar

Term	Contract	Receive Notional Principal (US$)	Fixed Annual Rate (US%)	Pay Notional Principal (Cdn$)	Fixed Annual Rate (Cdn %)
January 2011 – March 2015	Swap	37,500,000	4.71	38,287,500	5.24
January 2011 – March 2017	Swap	67,500,000	5.48	68,917,500	5.89
January 2011 – March 2020	Swap	155,000,000	6.03	158,255,000	6.45

Beyond the hedging strategy, we also mitigate risk by having a well diversified marketing portfolio for oil and natural gas by transacting with a number of counterparties to limit our exposure to any one counterparty. The majority of our oil and natural gas volumes are sold into the Alberta and Saskatchewan index priced markets with terms of one year or less. Approximately 95% of our oil volumes are sold into the Saskatchewan market and 5% into the Alberta market. Approximately 55% of our natural gas volumes are sold into the Alberta market and 45% into the Saskatchewan market.

For 2010, our commodity mix was approximately 89% oil and NGLs and 11% natural gas.

The Corporation recorded a realized derivative gain on oil and gas hedge contracts of $5.5 million in 2010.

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 Credit Policy that is formally 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 Cdn$500,000. 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 approximately 28 purchasers and its financial hedging portfolio consists of eight 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 65 percent of the Corporation's physical sales portfolio.

Revenue Sources

For the year ended December 31, 2010, 4% of the revenue from our properties before hedging and royalties was derived from natural gas and 96% from crude oil and natural gas liquids.

For the year ended December 31, 2009, 5% of the revenue from our properties before hedging and royalties was derived from natural gas and 95% from crude oil and natural gas liquids.

For the year ended December 31, 2008, 7% of the revenue from our properties before hedging and royalties was derived from natural gas and 93% from crude oil and natural gas liquids.

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

Personnel

As at December 31, 2010, we had 255 full-time employees and 63 consultants at our head office. In the field we had 206 full-time field staff, 2 part-time field staff and 48 consultants.

Reorganizations

On January 16, 2008, the Trust completed the Pilot Arrangement, through its wholly-owned subsidiary CPGPC for total consideration of approximately $78.5 million paid through the issuance of 0.1284 of a Trust Unit for each issued and outstanding Pilot common share. As a result of internal reorganization steps taken subsequent to the acquisition of Pilot, all of the material oil and gas assets of the Trust continued to rest in the Limited Partnership.

On January 15, 2009, the Trust completed the Villanova Arrangement for total consideration of approximately $134.7 million, comprised of 4,625,294 million Trust Units and assumed debt. The Villanova consolidation acquisition extends the Trust's Bakken play in southeast Saskatchewan, adding 26 net sections of undeveloped Bakken land.

On July 2, 2009, Wild River, the Trust, CPGPC and certain other parties completed the Conversion Arrangement for total consideration of 4,363,316 shares. Pursuant to the Conversion Arrangement, the Corporation acquired all of the issued and outstanding Trust Units. Holders of Trust Units received, for each Trust Unit held, one Common Share of the Corporation. In addition, the Trust was liquidated and dissolved and the Corporation received all of the assets and assumed all of the liabilities of the Trust. In connection with the Conversion Arrangement, the Corporation adopted a new restricted share bonus plan under which all restricted units previously issued under the Trust's existing restricted unit bonus plan were amended and restated such that the holders thereof have, upon vesting, the right to acquire Common Shares instead of Trust Units, on a one-for-one basis and on substantially the same terms, under the restricted share bonus plan. Pursuant to the Conversion Arrangement, the Trust also assigned its DRIP and all associated agreements to the Corporation, and the Corporation subsequently amended and restated them so that, among other things, all participants in the DRIP were deemed to be participants in the amended and restated DRIP without any further action on their part and the holders of Common Shares were able to participate in the amended and restated DRIP with respect to any cash dividends declared and paid by the Corporation on the Common Shares. In connection with the Conversion Arrangement, the Corporation also changed its name to Crescent Point Energy Corp.

On July 3, 2009, the Corporation closed the Gibraltar Arrangement for total consideration of approximately $200.5 million, comprised of 4,112,272 Common Shares and assumed debt. The Gibraltar Arrangement continued the Corporation's consolidation strategy for the lower Shaunavon play in southwest Saskatchewan.

On October 22, 2009, the Corporation closed the Wave Arrangement for a total consideration of approximately $706.0 million, comprised of 17,497,643 Common Shares and assumed debt. The Wave Arrangement continued the Corporation's consolidation strategy for the Lower Shaunavon play in southwest Saskatchewan.

On December 15, 2009, the Corporation closed the TriAxon Arrangement for total consideration of approximately $254.9 million, comprised of 6,276,775 Common Shares and assumed debt. The TriAxon Arrangement increased the Corporation's assets in the Bakken and Viking light oil resource plays in Saskatchewan.

On July 2, 2010, the Corporation closed the Shelter Bay Arrangement for total consideration of approximately $1.2 billion, comprised of 24,397,586 Common Shares and assumed debt. The Shelter Bay Arrangement solidified the Corporation's position in each of the Bakken and Lower Shaunavon oil resource plays in Saskatchewan.

On July 5, 2010, the Corporation closed a plan of arrangement under Section 193 of the ABCA with a private company for total consideration of approximately $95.6 million, comprised of 740,537 Common Shares and assumed debt. The acquisition of this private company gave the Corporation more than one million net acres of exploratory land in southern Alberta.

On August 20, 2010, the Corporation closed the Ryland Oil Arrangement for total consideration of approximately $116.3 million, comprised of 2,178,719 Common Shares and assumed debt. The Ryland Oil Arrangement solidified the Corporation's position in the Flat Lake Bakken play in southeast Saskatchewan and increased it undeveloped land position in North Dakota, United States.

Social and Environmental Policies

The Corporation established a reclamation fund to fund future asset retirement obligation costs and environmental emissions reduction costs. From January 1, 2008 to December 31, 2008, we allocated $0.30 per boe of production as well as lump-sum contribution of $1,000,000. From January 1, 2009 to December 31, 2009, we allocated $0.30 per boe of production, as well as lump-sum contribution of $1,000,000. From January 1, 2010 to March 30, 2010, we allocated $0.30 per boe of production. From April 1, 2010 to December 31, 2010, we allocated $0.45 per boe of production. Additional contributions can be made at the discretion of management.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The Corporation

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, 2010 contained in the consolidated report of GLJ dated March 14, 2011 (the "**Crescent Point Reserve Report**"). The Crescent Point Reserve Report evaluated, as at December 31, 2010, 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, 2011 forecast price and cost assumptions. GLJ evaluated approximately 34 percent of the assigned total proved plus probable reserves and 29 percent of the total proved plus probable value discounted at 10 percent. Sproule evaluated approximately 66 percent of the assigned total proved plus probable reserves and 71 percent of the total proved plus probable value discounted at 10 percent. Sproule evaluated a majority of our Bakken properties in southeast Saskatchewan, the Shaunavon properties in southwest Saskatchewan and the Neutral Hills portion of our Alberta properties. They had prepared an engineering report for essentially the same assets in the previous year. Sproule incorporated the GLJ forecast price and cost escalation assumptions in their evaluation. GLJ prepared the Crescent Point Reserve Report by consolidating the GLJ evaluation with the Sproule evaluation, all run on 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 us 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)(2)

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent	
Reserves Category	Company Gross *(Mbbl)*	Company Net *(Mbbl)*	Company Gross *(Mbbl)*	Company Net *(Mbbl)*	Company Gross *(MMcf)*	Company Net *(MMcf)*	Company Gross *(Mbbl)*	Company Net *(Mbbl)*	Company Gross *(Mboe)*	Company Net *(Mboe)*
Proved										
Producing	115,627	101,201	1,080	1,047	65,957	60,212	3,508	3,187	131,208	115,469
Developed Non-Producing	7,456	6,521	516	480	11,334	10,038	359	327	10,220	9,001
Undeveloped	96,980	89,361	125	119	44,347	41,305	4,885	4,585	109,381	100,948
Total Proved	220,063	197,083	1,721	1,646	121,638	111,556	8,753	8,098	250,810	225,419
Total Probable	114,684	102,935	784	716	54,771	49,547	4,134	3,816	128,731	115,725
Total Proved Plus Probable	334,747	300,018	2,505	2,362	176,408	161,103	12,887	11,914	379,540	341,144

Note:
(1) Numbers may not add due to rounding.
(2) Reserves are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets are less than 0.3% of the company gross total oil equivalent reserves, on a proved plus probable basis.

Net Present Value of Future Net Revenue of Oil and Gas Reserves(1)

	Net Present Value of Future Net Revenue Before Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10%/year	
Reserves Category	0% *(M$)*	5% *(M$)*	10% *(M$)*	15% *(M$)*	20% *(M$)*	*($/boe)*	*($/Mcfe)*
Proved							
Producing	6,501,248	4,639,348	3,711,792	3,144,707	2,755,949	32.15	5.36
Developed Non-Producing	461,959	365,748	304,628	262,415	231,489	33.84	5.64
Undeveloped	4,484,533	3,092,486	2,266,178	1,730,281	1,359,929	22.45	3.74
Total Proved	11,447,740	8,097,583	6,282,598	5,137,403	4,347,367	27.87	4.65
Total Probable	7,275,927	4,217,882	2,887,940	2,163,513	1,712,368	24.96	4.16
Total Proved Plus Probable	18,723,668	12,315,464	9,170,538	7,300,916	6,059,735	26.88	4.48

	Net Present Value of Future Net Revenue After Income Taxes Discounted at (%/year)					Unit Value After Income Tax Discounted at 10%/year	
Reserves Category	0% *(M$)*	5% *(M$)*	10% *(M$)*	15% *(M$)*	20% *(M$)*	*($/boe)*	*($/Mcfe)*
Proved							
Producing	6,025,976	4,375,267	3,532,390	3,008,994	2,646,436	30.59	5.10
Developed Non-Producing	336,291	264,750	219,297	187,923	164,962	24.36	4.06
Undeveloped	3,274,080	2,198,502	1,558,859	1,144,818	860,090	15.44	2.57
Total Proved	9,636,347	6,838,519	5,310,545	4,341,734	3,671,488	23.56	3.93
Total Probable	5,315,113	3,060,481	2,076,861	1,540,342	1,206,329	17.95	2.99
Total Proved Plus Probable	14,951,460	9,899,000	7,387,406	5,882,077	4,877,817	21.65	3.61

Note:
(1) Reserves are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets are less than 0.3% on a before tax basis and 0.2% on an after tax basis, of the total net present value of future net revenue discounted at 10% per year, on a proved plus probable basis.

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								
Producing	11,820,567	1,741,029	3,367,676	95,269	115,345	6,501,248	475,272	6,025,976
Developed Non-Producing	815,959	110,738	191,879	44,446	6,937	461,959	125,668	336,291
Undeveloped	9,797,930	937,457	2,123,008	2,194,794	58,139	4,484,533	1,210,453	3,274,080
Total Proved	22,434,456	2,789,223	5,682,562	2,334,510	180,420	11,447,740	1,811,393	9,636,347
Total Probable	13,069,181	1,562,795	3,451,793	732,405	46,260	7,275,927	1,960,814	5,315,113
Total Proved plus Probable	35,503,637	4,352,019	9,134,355	3,066,914	226,681	18,723,668	3,772,207	14,951,460

Note:
(1) Reserves are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets are less than 0.3% of the total future net revenue before income taxes and less than 0.3% of the total future net revenue after income taxes, on a proved plus probable basis.

Future Net Revenue by Production Group

	Future Net Revenue Before Income Taxes[3] (Discounted at 10% per year) *(M$)*	Unit Value *($/boe)*	*($/Mcfe)*
Proved			
Light and Medium Oil[1]	6,171,444	28.45	4.74
Heavy Oil[1]	42,002	23.30	3.88
Natural Gas[2]	69,152	10.36	1.73
Total Proved[4]	**6,282,598**	**27.87**	**4.65**

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) Reserves are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets are less than 0.2% of the total future net revenue before income taxes discounted at 10% per year, on a proved plus probable basis.

	Future Net Revenue Before Income Taxes[3] (Discounted at 10% per year) (M$)	Unit Value *($/boe)*	*($/Mcfe)*
Proved Plus Probable			
Light and Medium Oil[1]	9,013,959	27.38	4.56
Heavy Oil[1]	58,905	22.62	3.77
Natural Gas[2]	97,674	10.46	1.74
Total Proved Plus Probable[4]	**9,170,538**	**26.88**	**4.48**

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) Reserves are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets are less than 0.3% of the total future net revenue before income taxes discounted at 10% per year, on a proved plus probable basis.

For future net revenue of the total proved reserves, discounted at 10 percent, 98% of the revenue is from light and medium oil, 1% from heavy oil, and 1% from natural gas. For the total proved plus probable reserves, 98% of the revenue is from light and medium oil, 1% from heavy oil, and 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 tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; 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, 2010 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									
2011	4.50	4.16	88.00	86.22	90.54	67.26	54.32	2.0	0.980
2012	5.15	4.74	89.00	89.29	91.96	68.75	56.25	2.0	0.980
2013	5.75	5.31	90.00	90.92	92.74	70.01	57.28	2.0	0.980
2014	6.25	5.77	92.00	92.96	94.82	71.58	58.56	2.0	0.980
2015	6.75	6.22	95.17	96.19	98.12	74.07	60.60	2.0	0.980
2016	7.10	6.53	97.55	98.62	100.59	75.94	62.13	2.0	0.980
2017	7.32	6.76	100.26	101.39	103.42	78.07	63.87	2.0	0.980
2018	7.47	6.90	102.74	103.92	106.00	80.02	65.47	2.0	0.980
2019	7.62	7.06	105.45	106.68	108.82	82.15	67.21	2.0	0.980
2020	7.77	7.21	107.56	108.84	111.01	83.80	68.57	2.0	0.980
2021+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.980

The weighted average realized sales prices before hedging for the year ended December 31, 2010 were $4.12/Mcf for natural gas, and $73.46/bbl for crude oil and NGLs.

Reconciliations of Changes in Reserves and Future Net Revenue

Reserves Reconciliation[1][3]

The following table sets forth a reconciliation of the Corporation's Company Gross reserves by total proved, probable and total proved plus probable reserves as at December 31, 2010 against such reserves as at January 1, 2010 based on forecast price and cost assumptions.

	Total Oil (*Mbbl*)			Light and Medium Oil (*Mbbl*)			Heavy Oil (*Mbbl*)			Natural Gas Liquids (*Mbbl*)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2010[1]	162,504	85,688	248,192	160,521	84,907	245,427	1,983	781	2,765	6,870	3,341	10,212
Discoveries	131	75	205	131	75	205	-	-	-	-	-	-
Extensions and Improved Recovery	23,315	18,756	42,072	23,308	18,743	42,051	7	14	21	1,417	750	2,166
Technical Revisions	15,860	(10,293)	5,567	15,953	(10,239)	5,714	(93)	(54)	(147)	796	(176)	620
Acquisitions	42,178	23,068	65,245	42,160	23,025	65,185	18	43	61	1,108	537	1,645
Dispositions	(2,925)	(1,826)	(4,750)	(2,925)	(1,826)	(4,750)	-	-	-	(615)	(318)	(933)
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(19,279)	-	(19,279)	(19,085)	-	(19,085)	(194)	-	(194)	(822)	-	(822)
December 31, 2010[2]	221,784	115,468	337,252	220,063	114,684	334,747	1,721	784	2,505	8,753	4,134	12,887

	Total Gas (*MMcf*)			Conventional Natural Gas (*MMcf*)			Coal Bed Methane (*MMcf*)			BOE (*Mboe*)		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
January 1, 2010[1]	97,888	41,519	139,408	97,888	41,519	139,408	-	-	-	185,689	95,949	281,638
Discoveries	-	-	-	-	-	-	-	-	-	131	75	205
Extensions and Improved Recovery	19,369	10,597	29,966	19,369	10,597	29,966	-	-	-	27,959	21,273	49,231
Technical Revisions	4,569	(4,460)	108	4,569	(4,460)	108	-	-	-	17,415	(11,210)	6,205
Acquisitions	18,024	9,102	27,125	18,024	9,102	27,125	-	-	-	46,290	25,121	71,411
Dispositions	(3,861)	(1,987)	(5,848)	(3,861)	(1,987)	(5,848)	-	-	-	(4,183)	(2,476)	(6,658)
Economic Factors	-	-	-	-	-	-	-	-	-	-	-	-
Production	(14,351)	-	(14,351)	(14,351)	-	(14,351)	-	-	-	(22,492)	-	(22,492)
December 31, 2010[2]	121,638	54,771	176,408	121,638	54,771	176,408	-	-	-	250,810	128,731	379,540

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.

(3) Reserves are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets are less than 0.3% of the company gross total oil equivalent reserves, on a proved plus probable basis.

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 proved undeveloped gross 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
Prior	6,127	6,127	180	180	4,455	4,455	153	153	7,203	7,203
2008	1,192	44,748	6	128	3,537	20,014	17	3,009	1,805	51,221
2009	15,495	62,431	-	122	9,113	30,012	745	3,551	17,758	71,106
2010	18,581	96,980	-	125	19,269	44,347	1,317	4,885	23,110	109,381

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
Prior	5,145	5,145	96	96	2,844	2,844	106	106	5,821	5,821
2008	691	25,981	91	169	642	10,920	9	1,458	898	29,428
2009	22,743	47,301	-	167	10,976	15,868	1,090	2,013	25,663	52,127
2010	18,115	69,189	39	212	12,675	26,143	734	2,511	21,000	76,270

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 restrictions.

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 proved reserves and proved plus probable reserves (using forecast prices and costs).

Company Annual Capital Expenditures (M$)(2)
Entity Description

Year	Total Proved	Total Proved Plus Probable
2011	762,767	946,868
2012	619,442	873,258
2013	624,852	780,460
2014	250,614	350,125
2015	14,795	40,363
2016	5,206	9,005
2017	6,961	6,393
2018	5,519	4,714
2019	3,490	5,180
2020	6,053	6,753
2021	3,082	3,728
2022	3,329	3,618
Subtotal(1)	2,306,111	3,030,467
Remainder	28,399	36,448
Total(1)	2,334,510	3,066,914
10% Discounted	1,967,304	2,577,430

Note:
(1) Numbers may not add due to rounding.
(2) Company annual capital expenditures are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets represent less than 0.4% and 0.7% of the total company capital expenditures discounted at 10% per year, on a proved and proved plus probable basis, respectively.

Company Annual Abandonment Costs (M$)(2)
Entity Description

Year	Total Proved	Total Proved Plus Probable
2011	3,629	3,282
2012	1,861	1,252
2013	2,809	2,142
2014	3,207	1,938
2015	3,468	1,976
2016	5,065	2,935
2017	4,297	3,156
2018	3,850	3,680
2019	4,449	3,338
2020	5,780	3,559
2021	5,538	3,169
2022	4,762	4,554
Subtotal(1)	48,716	34,980
Remainder	131,705	191,701
Total(1)	180,420	226,681
10% Discounted	45,178	37,347

Note:
(1) Numbers may not add due to rounding.
(2) Company annual abandonment costs are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets represent less than 0.2% of the total company abandonment costs discounted at 10% per year, on a proved and proved plus probable basis.

We estimate that our internally generated cash flow will be sufficient to fund the future development costs 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 dividend reinvestment plans), 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 4.25% per annum.

We expect to fund our total 2011 capital program with internally generated cash flow and although quarterly fluctuations in funding levels are expected, our objective is to reduce our current net debt level throughout 2011. 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. The production numbers stated refer to our working interest share before deduction of Crown and freehold royalties. 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, 2010.

Viewfield Bakken

Crescent Point spent 60 percent of its 2010 capital development program on its Viewfield Bakken light oil resource property in southeast Saskatchewan. The Corporation continued to consolidate and expand its position in this play through development and exploration drilling, land purchases and strategic acquisitions. In 2010, Crescent Point completed two strategic Viewfield Bakken consolidation acquisitions and increased its land holdings to more than 1,000 net sections. The Corporation drilled 176 net wells and significantly expanded its gas-gathering and processing infrastructure across the property.

Proved plus probable reserves grew from 119.4 MMboe to 173.1 MMboe; 45 percent over year end 2009. Technical and development reserves additions represented 66 percent, or 35.2 MMboe, of the year-over-year increase. Since acquiring Mission Oil and Gas in early 2007, the Corporation has added more than 119 MMboe of positive proved plus probable technical and development reserves, or 69 percent of the total proved plus probable Bakken reserves at year end 2010. The Corporation has 999 future locations booked to reserves as of year end 2010, up from 643 locations at year end 2009.

In 2009, Crescent Point successfully executed the first cemented liner fracture stimulation completion with encouraging results. To date, the Corporation has completed 180 cemented liner fracture stimulations in the Bakken. The benefits of a cemented liner completion include the unlimited number of fracture stages that can be placed at minimal incremental capital per stage, as well as better placement and control of fracture propagation, which improves both productivity and reserves for each well. Another significant benefit of a cemented liner completion

is that it facilitates the ability to re-enter the well in the future, to either apply additional fracture stimulations or to provide opportunities for future well optimization. Crescent Point expects that the cemented liner technology will be used on the majority of its budgeted Bakken horizontal wells to be fracture stimulated in 2011.

Also in 2010, Crescent Point continued to expand and evaluate its water flood pilot programs in the Bakken, converting an additional seven producing wells into water injection wells. The earliest pilot has continued to show encouraging results, with increased oil production seen in offsetting producing wells and a noticeable reduction in production decline rates. With this improved production performance, the ultimate recoverable proved plus probable reserves in the section were increased by 315 Mbbls in 2010 and now total over one million barrels of oil. Based on these results, the Corporation initiated three more water flood pilot projects by year end 2010 and has plans to initiate up to four additional water flood projects across the field in the 2011, each testing different areas of the field and various patterns and completion techniques.

For 2011, Crescent Point plans to spend up to 62 percent of its capital development budget in the Bakken play, drilling approximately 200 net wells. Up to $45 million has been earmarked for facilities infrastructure projects to accommodate Crescent Point's ongoing drilling program and future production growth in the area.

Shaunavon

One of Crescent Point's key operating strategies in 2010 was to continue the consolidation of assets in the Lower Shaunavon resource play in southwest Saskatchewan and to continue construction of the gathering and processing infrastructure.

Through a series of acquisitions and Crown land sales, Crescent Point increased its land holdings in the Shaunavon area to more than 600 net sections. Since the first Shaunavon acquisition in 2009, Crescent Point has added more than 15 MMboe of positive proved plus probable technical and development reserves, or 20 percent of the total proved plus probable Shaunavon reserves at year end 2010. The Corporation has 402 future locations booked to reserves as of year end 2010, up from 176 locations at year end 2009.

The Corporation initiated an active drilling program that resulted in 51.6 net horizontal oil wells with a 100 percent success rate. This included four successful operated drills in the Upper Shaunavon. The Corporation invested in infrastructure in the area, including the construction of oil batteries and crude oil gathering systems. Also, as of July 2010, gas conservation was initiated, utilizing third party facilities.

As of year end 2010, Crescent Point had booked proved plus probable reserves of 74.4 MMboe in the Shaunavon, including 8.4 MMboe due to positive technical and development reserve additions. These bookings represent a recovery factor of 1.9 percent of original-oil-in-place.

In 2010, Crescent Point initiated two additional water flood pilots. Both pilots started water injection late in fourth quarter 2010. In 2011, the Corporation expects to initiate a fourth pilot in the play, which will include three additional water injection wells in a section where the Corporation will downspace to eight wells per section. Also in 2011, the Corporation expects to convert an additional two producing wells to water injection in the Rapdan area.

For 2011, Crescent Point expects to spend approximately 16 percent of its capital development budget in the Shaunavon area. The Corporation expects to drill 44 net Shaunavon wells, including 35 net wells targeting the Lower Shaunavon and 9 net wells (7 operated) targeting the Upper Shaunavon. This includes the drilling of an additional 6 net infill locations to further prove-up the downspacing development potential of the field. Crescent Point expects to spend up to $27 million on facilities investments, including the expansion of crude oil gathering systems and the upgrading of key crude oil batteries. These facilities investments are expected to accommodate current and future growth in production volumes. During 2011, the Corporation also plans to build a 6 MMcf/d gas plant in order to conserve associated gas and NGL liquids.

Battrum and Cantuar

During 2010, Crescent Point continued to optimize production and reserves at Battrum and Cantuar through water flood optimization, infill drilling and re-completions. Since acquiring the Battrum property in early 2006, the Corporation has increased proved plus probable reserves from 5.6 MMboe to a total of 15.7 MMboe at year end 2010. During the same time frame, Crescent Point increased proved plus probable reserves at Cantuar from 9.7 MMboe to a total of 16.8 MMboe at year end 2010.

Also during 2010, Crescent Point achieved record working interest production levels at Battrum of more than 2,325 boe/d.

For 2011, the Corporation plans to continue with optimization projects at Battrum and Cantuar and to drill up to 10 (4.4 net) oil wells in Battrum and 10 (5.5 net) oil wells in Cantuar.

Oil and Gas Wells

Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
Southeast Saskatchewan	3,457	1,880	1	0
Southwest Saskatchewan	825	541	89	78
South Central Alberta	405	303	306	205
Northeast B.C./Peace River Arch	35	34	47	33
Montana, U.S.	10	7	1	1
Totals	4,732	2,765	444	317

Non-Producing Wells

Area	Oil		Gas	
	Gross	*Net*	*Gross*	*Net*
Southeast Saskatchewan	37	28	-	-
Southwest Saskatchewan	5	2	14	12
South Central Alberta	6	3	5	3
Northeast B.C./Peace River Arch	-	-	14	7
Montana, U.S.	-	-	-	-
Totals	48	33	33	22

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, 2010		
	Gross Acres	Net Acres	Net Acres Expiring Within One Year
British Columbia	4,180	3,004	645
Alberta	1,171,150	1,032,601	49,840
Saskatchewan	1,473,638	1,300,731	289,018
Manitoba	90,821	53,476	1,082
Montana, U.S.	447,474	371,394	147,889
North Dakota, U.S.	219,035	46,496	6,421
Total	3,406,298	2,807,702	494,895

The Corporation's drilling commitments and timing for properties with no attributed reserves are as follows:

($000's) Total	2011	2012	2013
22,927	18,202	2,625	2,100

Drilling Activity

The following table summarizes the gross and net exploration and development wells in which we participated during the year ended December 31, 2010.

	Development Wells		Exploration Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil wells[1]	374	277	23	18	397	295
Natural Gas wells	-	-	-	-	-	-
Service wells	5	5	1	1	6	6
Dry Holes	-	-	3	1	3	1
Total	379	282	27	20	406	302

Note:

(1) Drilling activity is presented on a consolidated country basis (Canada and the U.S.). The Corporation drilled 3 gross (0.5 net) U.S. oil exploration wells during the year ended December 31, 2010.

For details on the most important current and likely exploration and development activities during 2010, see "*Statement Of Reserves Data And Other Oil And Gas Information – Oil and Gas Properties*".

Additional Information Concerning Abandonment and Reclamation Costs

We estimate well abandonment costs stereotypically 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 4,382 net wells under the proved reserves category is $180 million undiscounted ($45 million discounted at 10%), of which a total of $8 million is estimated to be incurred in 2011, 2012 and 2013.

Tax Horizon

Crescent Point has tax pools of approximately $5.5 billion at December 31, 2010 to shelter future taxable income. Including the impact of income from the Partnership for the year ended January 31, 2011, the net tax pools remaining are approximately $4.7 billion. Based on this pool balance and the forecast of cash flows using $US 100.00 WTI, a 1.00 $US/$Cdn exchange rate and 2% inflation, with a 2011 capex budget of $800 million, Crescent Point does not expect to be taxable until 2014.

Costs Incurred

The following table summarizes our property acquisition costs, exploration costs and development costs for the year ended December 31, 2010. The total capital costs were approximately $3.0 billion in 2010.

($000's)	Acquisition Costs			
	Proved Properties	Unproved Properties	Exploration Costs	Development Costs
Canada	1,609,218	637,334	35,193	710,711
U.S.	-	41,970	1,913	-
Total	1,609,218	679,304	37,106	710,711

Production Estimates

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2011 in the estimates of future net revenue with forecast pricing from proved reserves disclosed above under the heading "Disclosure of Reserves Data".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Natural Gas	NGLs	Total
	(bbl/d)	*(bbl/d)*	*(Mcf/d)*	*(bbl/d)*	*(boe/d)*
Southeast Saskatchewan	49,773	-	20,737	2,904	56,133
Southwest Saskatchewan	16,932	-	4,308	21	17,671
South Central Alberta	2,064	505	17,154	65	5,494
Northeast B.C./Peace River Arch	526	4	5,703	114	1,595
U.S.	220	-	40	-	227
Total (1)	69,515	509	47,942	3,104	81,120

Production in the southeast and southwest Saskatchewan accounts for 69% and 22%, respectively, of the Corporation's proved production estimate in 2011.

The following table discloses for each product type the gross volume of production estimated by GLJ and Sproule for 2011 in the estimates of future net revenue with forecast pricing from proved plus probable reserves disclosed above under the heading "Disclosure of Reserves Data".

Region	Light and Medium Crude Oil	Heavy Crude Oil	Natural Gas	NGLs	Total
	(bbl/d)	*(bbl/d)*	*(Mcf/d)*	*(bbl/d)*	*(boe/d)*
Southeast Saskatchewan	58,783	-	24,349	3,442	66,283
Southwest Saskatchewan	18,975	-	4,418	21	19,732
South Central Alberta	2,374	524	18,437	71	6,043
Northeast B.C./Peace River Arch	590	4	6,165	119	1,741
U.S.	448	-	51	-	457
Total (1)	81,170	528	53,420	3,653	94,255

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

Production in southeast and southwest Saskatchewan accounts for 70% and 21%, respectively, of the Corporation's proved plus probable production estimate in 2011.

Production History

The following table discloses, on a quarterly and annual basis for the year ended December 31, 2010, our share of average daily production volume, prior to 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, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	2010
Light and Medium Crude Oil *(bbl/d)*	47,822	46,529	55,511	59,746	52,442
Heavy Crude Oil *(bbl/d)*	480	566	564	508	530
NGLs *(bbl/d)*	1,850	1,833	2,315	2,386	2,098
Natural gas *(Mcf/d)*	35,456	35,919	42,947	42,831	39,318
Total *(boe/d)*	56,061	54,915	65,548	69,779	61,623

Note:

(1) Production is presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets account for less than 0.3% of the total annual oil equivalent production.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Light and Medium Crude Oil[1]

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	2010
Prices Received – net of hedging	76.70	72.45	72.49	75.55	74.31
Royalties (Total Oil royalties less NGL's & Heavy Oil)	(13.96)	(13.07)	(11.85)	(12.43)	(12.76)
Production Costs	(11.07)	(11.39)	(11.76)	(11.93)	(11.57)
Transportation Costs	(1.71)	(1.65)	(1.55)	(1.76)	(1.67)
Netback	49.96	46.34	47.33	49.43	48.31

Note:

(1) Prices received, royalties, production costs and transportation costs incurred are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets account for less than 0.2% of the total annual light and medium crude oil production, therefore the netback on U.S. production is not presented.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred –Heavy Crude Oil[1]

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	2010
Prices Received – net of hedging	66.93	66.03	63.19	58.31	63.47
Royalties	(3.98)	(6.81)	(5.32)	(4.82)	(5.29)
Production Costs	(9.66)	(10.38)	(10.25)	(9.21)	(9.88)
Transportation Costs	(1.50)	(1.50)	(1.35)	(1.36)	(1.42)
Netback	51.79	47.34	46.27	42.92	46.88

Note:

(1) Prices received, royalties, production costs and transportation costs incurred are from Canadian assets; the Corporation's U.S. assets did not produce any heavy crude oil.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred –NGLs[1]

	Three Months Ended				Year Ended
($ per bbl)	March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	2010
Prices Received	54.68	48.44	51.30	58.11	53.37
Royalties	(5.86)	(4.69)	(5.10)	(7.14)	(5.76)
Production Costs	(7.89)	(7.62)	(8.32)	(9.17)	(8.31)
Transportation Costs	(1.22)	(1.10)	(1.10)	(1.35)	(1.20)
Netback	39.71	35.03	36.78	40.45	38.10

Note:

(1) Prices received, royalties, production costs and transportation costs incurred are from Canadian assets; the Corporation's U.S. assets did not produce any NGLs.

Prices Received, Royalties, Production Costs and Transportation Costs Incurred – Natural Gas[1]

($ per Mcf)	Three Months Ended March 31, 2010	June 30, 2010	Sept. 30, 2010	Dec. 31, 2010	Year Ended 2010
Prices Received – net of hedging	5.09	4.72	4.21	4.42	4.58
Royalties	(0.86)	(0.74)	(0.35)	0.30	(0.38)
Production Costs	(1.17)	(1.22)	(1.41)	(1.26)	(1.27)
Transportation Costs	(0.43)	(0.34)	(0.19)	(0.19)	(0.28)
Netback	2.63	2.42	2.26	3.27	2.65

Note:

(1) Prices received, royalties, production costs and transportation costs incurred are presented on a consolidated country basis (Canada and U.S.). The Corporation's U.S. assets account for less than 0.9% of the total annual natural gas production, therefore the netback on U.S. production is not presented.

Production Volume by Field

The following table discloses for each important field, and in total, our production volumes for the year ended December 31, 2010 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)*	
Southeast Saskatchewan	38,026	-	1,933	14,354	42,351	69
Southwest Saskatchewan	12,378	-	13	3,461	12,968	21
South Central Alberta	1,468	530	64	16,014	4,731	8
Northeast B.C./Peace River Arch	485	-	88	5,155	1,432	2
U.S.	85	-	-	334	141	-
Total	52,442	530	2,098	39,318	61,623	100

ADDITIONAL INFORMATION RESPECTING CRESCENT POINT

Directors and Officers

Crescent Point has a board of directors currently consisting of seven 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 30, 2011.

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	Vice President, Engineering and Business Development	Not applicable
Dave P. Balutis Calgary, Alberta	Vice President, Exploration	Not applicable
Brad Borggard Calgary, Alberta	Vice President, Corporate Planning	Not applicable
Derek Christie Calgary, Alberta	Vice President, 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

Name and Municipality of Residence	Position Held with the Corporation	Date First Elected or Appointed as Director
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) Calgary, Alberta	Director and Chairman	2003
Paul Colborne (2), (4) Calgary, Alberta	Director	2003
D. Hugh Gillard (1), (2), (5) Calgary, Alberta	Director	2003
Gregory G. Turnbull (2), (5) Calgary, Alberta	Director	2003
Kenney F. Cugnet (3), (4), (5) Weyburn, Saskatchewan	Director	2003
Gerald A. Romanzin(1), (3) Calgary, Alberta	Director	2004

Notes:
(1) Member of the Audit Committee.
(2) Member of the Compensation Committee.
(3) Member of the Reserves Committee.
(4) Member of the Environment, Health and Safety Committee.
(5) Member of Corporate Governance and Nominating Committee.

As at March 15, 2011, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 3,785,535 Common Shares, representing approximately 1.4% of the issued and outstanding Common Shares. Including restricted shares, ownership increases to 2.2% 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, Geologists and Geophysicists of Alberta and serves on the board of directors of Bellamont Exploration Ltd., Wild Stream Resources Ltd. and of each of the general partners of Catapult Energy 2008 Inc. and Aston Hill Energy 2010 GP Inc. He also serves on the 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 served on the Board of Shelter Bay until 2010. He is a Chartered Accountant, a member of the Institute of Chartered Accountants of Alberta and a member of the Financial Executive Institute. Mr. Tisdale holds a Bachelor of Commerce degree (with distinction) from the University of Alberta.

C. Neil Smith, Vice President, Engineering and Business Development

C. Neil Smith is the Vice President, Engineering and Business Development of Crescent Point, a role he has held with Crescent Point since 2003. He has worked in the oil and gas industry since 1986, having held a variety of roles with companies such as Shelter Bay, Amoco Canada Petroleum Ltd. and Coles Gilbert Associates Ltd., the predecessor to Gilbert Laustsen Jung Associates Ltd.

Mr. Smith is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He is a director of the Petroleum and Acquisition Association and also serves on the board of directors of the Small Explorers and Producers Association of Canada. 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.

Dave P.Balutis, Vice President, Exploration

Dave Balutis is the Vice President, Exploration of Crescent Point, a role he has held with Crescent Point since 2003. He was also a founder of the company in 2001. Mr. Balutis has worked in the oil and gas industry since 1981, having held a variety of roles with companies such as Magin Energy Inc., Numac Energy Ltd. and Dome Petroleum Ltd.

Mr. Balutis is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He holds a Bachelor of Science degree in geology (with honours) from the University of Alberta.

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, Geosciences

Derek Christie is the Vice President, Geosciences of Crescent Point, a role he has held with Crescent Point since January 2010. Prior to that, he was Manager, Geology for Crescent Point. He has been with the company 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 the Association of Professional Engineers, Geologists and Geophysicists of Alberta 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 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 the Association of Professional Engineers, Geologists and Geophysicists of Alberta. 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 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 Canadian Association of Petroleum and Land Administration and of the Petroleum and Acquisition Divestment Association. She is also a committee member with the Calgary Chamber of Commerce and a member of 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 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 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 the Professional Engineers, Geologists and Geophysicists of Alberta 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 is a partner with McCarthy Tétrault LLP law firm, practicing in the area of corporate and securities law.

Mr. Eade holds a Bachelor of Commerce degree (with honours) 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 2001. 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 also served on the Board of Directors of Shelter Bay until 2010.

Mr. Bannister is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and serves on the board of directors of Cequence Energy Ltd. and Surge Energy Inc. Formerly, he was a director of Mission Oil and Gas Inc., Breaker Energy, Impact Energy Inc., Boomerang Resources Ltd. and Laurasia Resources Ltd. Mr. Bannister holds a Bachelor of Science degree in geology.

Paul Colborne, Director

Paul Colborne is the president of StarValley Oil and Gas Ltd., a private oil and gas company. He was a founder of CPEL in 2001 and was the president and CEO of CPEL until its reorganization into Crescent Point Energy Trust in September 2003. Mr. Colborne has been on the board of Crescent Point and its predecessor since 2001 and has worked in the oil and gas industry since 1987, having led companies such as StarPoint Energy Ltd. and Startech Energy Ltd.

His expertise in law, including securities, banking, oil and gas and commercial law, has resulted in the successful completion of numerous corporate and commercial transactions. As well, Mr. Colborne has authored and presented a number of papers respecting the oil and gas industry.

Mr. Colborne is also the chairman of Legacy Oil and Gas Inc., a publicly traded company, and of Surge Energy Inc. He also serves on the boards of Cequence Energy Ltd. and Wild Stream Exploration. Formerly, Mr. Colborne served as chairman of TriStar Oil and Gas Ltd. and Seaview Energy Ltd., and served as a director for Westfire Energy Ltd., Twin Butte Energy Ltd. and Breaker Energy. He holds a Bachelor of Laws degree and a Bachelor of Arts degree in economics from the University of Calgary.

D. Hugh Gillard, Director

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 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, Director

Greg Turnbull is a partner with McCarthy Tétrault LLP law firm and is the regional managing partner of 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, Seaview Energy Inc., Hawk Exploration Ltd., Hyperion Exploration Inc. and Sonde Resources Corp. 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.

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 Energy Services Ltd. 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.

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.

Mr. Turnbull was a director of Mobilift Inc., a corporation engaged in the development, system integration and commercialization of innovative fall prevention technology. Mobilift Inc. was placed into receivership in September, 2001 by its major creditor after Mr. Turnbull left the board in August, 2001.

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 on the Common Shares. 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 Premium Dividend and Dividend Reinvestment Plan (the "**DRIP Plan**"), 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 Plan) of a Common Share on the applicable distribution date. The DRIP Plan 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 Plan. 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 Plan 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 Plan.

From October 31, 2006 to December 2007, the Trust used the proceeds from the issuance of Trust Units under the DRIP Plan to reduce the Trust's then outstanding debt. The operation of the DRIP Plan was suspended in December 2007 and was reinstated as of December 31, 2008. The DRIP plan was in effect through the year of 2009 except for June 2009. The DRIP plan was in effect through the year 2010.

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. The Restricted Share Bonus Plan authorizes the Corporation to issue up to a maximum of 11,000,000 Common Shares pursuant to the redemption of Restricted Shares granted under the Restricted Share Bonus Plan.

Unless otherwise determined by the Board of Directors of the Corporation at the time of a particular grant, Restricted Shares will vest and become available for redemption as to 33 1/3% on each of the first, second and third anniversaries of the grant date. 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.

Credit Facilities

The Corporation has credit facilities (the "**Credit Facilities**") which provide for a $1.5 billion extendible revolving loan facility with a permitted increase (subject to certain conditions) to $2.0 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, alternate 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 1.0% to 4.0% depending on the Corporation's senior debt to EBITDA ratio. The Credit Facilities are guaranteed by certain material restricted subsidiaries currently being CPHI and the Partnership. The Credit Facilities are unsecured. The Credit Facilities are subject to review on an annual basis, with the next review anticipated to take place by June 10, 2011. Various borrowing options are available under the Credit Facilities, including Canadian prime rate-based advances, U.S. base rate-based advances, libor 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 maturity should the lender not agree to an annual extension. The Syndicated Credit Facility constitutes a revolving credit facility for a 3 year term which is extendible annually for a 1, 2 or 3 year period (subject to a maximum 3 year term at any time). 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 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 – 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. Natural gas exported from Canada is subject to regulation by the National Energy Board ("**NEB**") and the government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of less than two years requires a general short term export license while terms greater than two years require a specific license for the particular gas sold (in quantities of not more than 30,000 m3/d). Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity 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 governments of Alberta and Saskatchewan also regulate the volume of natural gas, which may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

Pricing and Marketing – Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers. Oil prices are primarily based on worldwide supply and demand. The specific price paid depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms 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 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 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. The 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 determine whether exports to the U.S. or Mexico will be allowed provided that any export restrictions do not: (i) reduce the proportion of energy resource exported relative to domestic use (based upon 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.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

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.

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 are 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 new 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 new 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. New royalty rates will be determined on a monthly basis.

The new 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 new 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 can make a one-time election to produce the well under the Transitional Program royalty rates or the new 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 will revert to the new 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 have already opted for the Transitional Program royalty rates prior to January 1, 2011 have 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 new Royalty Framework rates.

Incentive Programs

From time to time the governments of Canada, Alberta, British Columbia and Saskatchewan 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.

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 new 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 provides a limited royalty reduction for qualifying exploratory and development natural gas wells spudded or deepened on or after May 1, 2010, 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 has been retained under the new Royalty Framework. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy determines which projects qualify for the IETP, as well as the level of support that will be provided. The deadline for the IETP's fifth round of applications was November 15, 2009.

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 provides 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 will receive a royalty credit of $200 per metre drilled, up to a prescribed maximum percentage of the operator's royalties. The maximum percentage will be 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 is only available to companies that are or will be recognized as having royalty payment obligations pursuant to applicable regulation. Any DRC royalty credits not used prior to March 31, 2011 will be 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 provides that the NWRR will be available to qualifying wells that commence or recommence producing conventional oil or natural gas between April 1, 2009 and March 31, 2011. Pursuant to the New Well Royalty Reduction Regulation, the NWRR reduces royalties on production from qualifying wells 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 first 7949 cubic metres of eligible oil or oil equivalent is produced, the date the well becomes part of a Project under the Oil Sands Royalty Regulation, 2009, or March 31, 2012, whichever occurs 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 will become a permanent feature of Alberta's royalty regime. The NWRR is now referred to as the New Well Royalty Rate as it provides for a 5% royalty from the outset, as opposed to reducing an existing royalty to 5%.

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**") will reduce 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 7949 cubic metres of oil equivalent is produced. Finally, the Horizontal Oil New Well Royalty Rate ("**HONWRR**") will reduce 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 7949 cubic metres of oil equivalent and 18 months for wells drilled to measured depths from 0 to 2,499 metres, to a maximum of 15,899 cubic metres of oil equivalent and 48 months for wells drilled to measured depths in excess of 4,500 metres. Final implementation of the foregoing initiatives is expected in June 2011. The NWRR, SGNWRR, and CMNWRR will apply retroactively to production produced on or after May 1, 2010. The HGNWRR and HONWRR will be 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 New Well Royalty Rate (NWRR), the Horizontal Gas NWRR, 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 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 lands other than Crown lands, the tax levied in respect of freehold oil and gas production in the Province of Saskatchewan is determined by reducing the Crown royalty rate that would otherwise be payable if the lands were Crown lands by a fixed amount. Currently, this reduction ranges from 6.9% to 12.5% depending on the classification of the oil or gas.

On June 14, 2010 the SER released a letter outlining significant changes to the current administrative provisions related to natural gas valuation under the government's Process Renewal and Infrastructure Management Enhancements ("**PRIME**") initiative. Among other changes, PRIME will introduce a new index based pricing for natural gas and will eliminate operators' option to elect between the monthly reference price prescribed by the SER and the operator's average monthly gas price for royalty/tax purposes. All natural gas, other than natural gas produced from oil wells and sold to a gas plant at or upstream of the plant inlet, will be valued based on the SER prescribed price for royalty/tax purposes. Furthermore, 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. While an exact implementation date for PRIME has not been set, the SER anticipates that it will be implemented in late 2011.

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 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 sustainable development 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 holiday oil volume of 10,000 m^3;

- *Deep Drilling Incentive* provides licensees who drill a well to a total depth sufficient to penetrate 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 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 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.

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, 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 and storage, land reclamation, habitat protection, and minimum setbacks of oil and gas activities from fresh 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 oxide 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 British Columbia is, for the most part, set out in the *Environmental Management Act* ("**EMA**") and the *Petroleum and Natural Gas Act*, which regulate the storage, discharge and disposal of air contaminants, effluent and hazardous waste into the environment. Specifically, the Oil and Gas Waste Regulation under the EMA regulates hydrogen sulphide and nitrogen oxide emissions from oil and gas facilities. The EMA provides for the imposition of significant penalties in the

event of non-compliance and for the remediation of contaminated sites. New oil and gas projects, or modifications to existing projects, may be subject to a review under the *Environmental Assessment Act*.

Environmental legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material, or in the suspension or revocation of necessary licences and approvals. Crescent Point may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject Crescent Point to statutory strict liability in the event of an accidental spill or discharge from a licensed 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, 2010, Crescent Point owned approximately 12,727 gross (7,087 net) wells, for which abandonment and reclamation costs are expected to be incurred. During the 2010 financial year, Crescent Point spent approximately $2.7 million on well abandonments and environmental remediation activities. Crescent Point estimates that it will spend approximately $3.5 million on well abandonments and environmental remediation and reclamation activities in 2011, and has budgeted accordingly. Crescent Point has estimated the net present value (discounted at eight percent per annum) of its total asset retirement obligations (wells and facilities) to be approximately $195.3 million as at December 31, 2010, based on a future liability (inflated at two percent per annum) of approximately $457.9 million. 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. Asset retirement obligation cost estimates are based on information published by the Energy Resources Conservation Board ("**ERCB**") 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.

Greenhouse Gas (GHG) 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 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 December 1, 2009, the Province of Saskatchewan re-introduced its climate change legislation originally introduced in May of 2009. Bill 95 establishes a framework of the provinces strategy to meet its target of reducing GHG emissions by 20% from 2006 levels by 2020 and fosters innovation in low-carbon technologies. So far, there has been no word on when Bill 95 is expected to come into force, and the potential impact of this legislation is uncertain as most of the operational details will be contained within the regulations following passage of the bill. These regulatory details include the baseline year, the anticipated reductions and the characterization of those regulated emitters to whom the targets apply. In addition, Bill 95 is unclear as to whether or not Saskatchewan will adopt an intensity-based approach similar to that in effect in Alberta, and so the operational effects of this legislation in the Province of Saskatchewan remain to be seen.

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 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.

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.

At the end of 2009, the United Nations Climate Change Conference, commonly known as the Copenhagen Accord, was held in Copenhagen, Denmark. While an accord that endorses, among other things, the continuation of the Kyoto Protocol and the need for global emissions reductions was generally accepted by the member countries at the Copenhagen Accord, the accord is generally viewed as not being legally binding and does not contain any binding commitments for reducing carbon dioxide emissions. In January 2010, the Government of Canada announced that it had submitted its 2020 emissions reduction target under the Copenhagen Accord, although it has not indicated how it will achieve such gas reduction. Canada's target, a 17% reduction from 2005 levels by the year 2020, is purportedly aligned with the U.S. target and is subject to adjustment to remain consistent with the U.S.

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. For a number of Canadian and North American political and economic reasons, it is now uncertain whether the proposed approach, or a variation thereof, will result in federal GHG regulations reflecting this approach. The Government of Canada is now evaluating both domestic and North American options for a cap and trade regulatory regime. 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. Proposed federal compliance mechanisms included: early offset credits, credits for federal Technology Fund contributions, credits obtained from other regulated entities which improved beyond legal requirements, offset credits obtained from non-regulated entities which reduced or removed GHGs; or international Clean Development Mechanism Credits. Crescent Point's facilities may use a number of strategies to meet federal requirements, including emissions trading, in-house reductions, or investments in a technology fund to research and develop GHG reduction technologies.

As part of its ongoing commitment to reduce GHG emissions, Crescent Point established an Environmental Emissions Reduction Fund in 2007. Currently $0.30 per produced boe is allocated into this fund. To date, $12.6 million has been allocated to the fund and $13.8 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 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 legislation and 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

The following are certain risk factors relating to our business which prospective investors should carefully consider before deciding whether to purchase Common Shares.

Reserve Estimates

The reserve and recovery information contained in the Crescent Point Reserve Report are only an 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. 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.

Volatility of Oil and Natural Gas Prices

Our results of operations and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are subject to fluctuations in response to relatively minor changes in supply, demand, market uncertainty and other factors that are beyond our control. These factors include, but are not limited to, worldwide political instability, foreign supply of oil and natural gas, the level of consumer product demand, government regulations and taxes, the price and availability of alternative fuels and the overall economic environment. Any decline in crude oil or natural gas prices may have a material adverse effect on our

operations, financial condition, borrowing ability, reserves and the level of expenditures for the development of oil and natural gas reserves. Any resulting decline in our cash flow could reduce dividends.

We use financial derivative instruments and other hedging mechanisms to try to limit a portion of the adverse effects resulting from changes in natural gas and oil commodity prices. To the extent we hedge our commodity price exposure, we forego some of the benefits we would otherwise experience if commodity prices were to increase. In addition, our commodity hedging activities could expose us to losses. Such losses could occur under various circumstances, including where the other party to a hedge does not perform its obligations under the hedge agreement, the hedge is imperfect or our hedging policies and procedures are not followed. Furthermore, we cannot guarantee that such hedging transactions will fully offset the risks of changes in commodities prices.

In addition, we regularly assess the carrying value of our assets in accordance with Canadian generally accepted accounting principles under the full cost method. If oil and natural gas prices become depressed or decline, the carrying value of our assets could be subject to downward revision.

Operating Costs and Production Levels

An increase in operating costs or a decline in our production level 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, reclamation, abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation.

The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in our production could result in materially lower revenues and cash flow and, therefore, could reduce the amount available for 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.

Marketing of Oil and Natural Gas Production

A decline in our ability to market our oil and natural gas production could have a material adverse effect on production levels or on the prices that we receive for our production which, in turn, could reduce dividends to Shareholders and affect the market price of our Common Shares.

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities. 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.

Fluctuations in Foreign Currency Exchange Rates

Fluctuations in foreign currency exchange rates could adversely affect our business, and could affect the market price of our Common Shares and payments of dividends to Shareholders. The price that we receive for a majority of our oil and natural gas is based on U.S. dollar denominated benchmarks, and, therefore, the price that we receive in Canadian dollars is affected by the exchange rate between the two currencies. A material increase in the value of the Canadian dollar relative to the U.S. dollar may negatively impact net production revenue by decreasing the Canadian dollars received for a given U.S. dollar price, negatively impacting future dividends and the future value of the Corporation's reserves as determined by independent evaluators. We could be subject to unfavourable exchange rate changes to the extent of

our investment in U.S. subsidiaries and to the extent that we have engaged, or in the future engage, in risk management activities related to foreign exchange rates, through entry into forward foreign exchange contracts or otherwise.

Acquisition of Additional Reserves

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 the majority 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.

Scope of Operations

If we expand our operations beyond oil and natural gas production in western Canada, with minor operations in Montana and North Dakota, 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. 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.

Reliance on Reserve Estimates

In determining the purchase price of acquisitions, we rely on both internal and external assessments relating to estimates of reserves that may prove to be materially inaccurate. Such reliance could adversely affect the market price of our Common Shares and payment of dividends to Shareholders.

The price we are willing to pay for reserve acquisitions is based largely on estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves we acquire may be less than expected, which could adversely impact cash flows and dividends to Shareholders. An initial assessment of an acquisition may be based on a report by engineers or firms of engineers that have different evaluation methods and approaches than those of our engineers, and these initial assessments may differ significantly from our subsequent assessments.

Operational Matters

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, 2010, approximately 13% 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 wilful misconduct.

Delays in Business Operations

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;
- accounting delays;
- 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;
- 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 delays could reduce the amount of cash available for dividends to Shareholders in a given period and expose us to additional third party credit risks.

Counterparty Risk

Although the Corporation monitors the credit worthiness of third parties it contracts with through a formal risk management 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.

In early 2009, the Corporation purchased trade credit insurance to partially protect against credit risk with financial counterparties.

Debt Service

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.

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 $1.5 billion extendible revolving loan facility with a permitted increase to $2.0 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.

Competition

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.

Operational Hazards and the Availability of Insurance

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. 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.

Environmental Concerns

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, 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 or a pipeline 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.

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 and regulations 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. 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.

Unforeseen Title Defects

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 Land Claims

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. We are unable to assess the effect, if any, that any such claim would have on our business and operations.

Changes in Tax and Other Laws

Changes in tax and other laws may adversely affect Shareholders. Income tax laws, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Corporation and 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.

Changes to Accounting Policies, including the Adoption of International Financial Reporting Standards ("IFRS")

In February 2008, the CICA Accounting Standards Board confirmed that IFRS will replace Canadian generally accepted accounting principles ("**GAAP**") in 2011 for Canadian publicly accountable enterprises. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that are being evaluated. The implementation of IFRS may result in significant adjustments to our consolidated financial statements, which could negatively impact our business.

Market Factors

Changes in market-based factors may adversely affect the trading price of our Common Shares. The market price of our Common Shares is primarily a function of anticipated dividends to Shareholders and the value of our properties. The market price of our Common Shares is therefore sensitive to a variety of market based factors, including, but not limited to, interest rates and the comparability of our Common Shares to other yield oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Ability to Pay Dividends

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.

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.

Loss of Key Personnel

Our operations are entirely independent from the Shareholders and loss of key management and other personnel could impact our business. 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.

Dilution

There may be future dilution. 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.

Availability of an Active Market for the Common Shares

There may not always be an active trading market for the Common Shares. While there is currently an active trading market for our Common Shares in Canada, we cannot guarantee that an active trading market will be sustained.

Failure to Realize Anticipated Benefits of Prior Acquisitions

The Corporation, and the Trust prior to the Conversion Arrangement, have completed a number of acquisitions since December 31, 2008, which were completed 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 will be 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.

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 2010 the Corporation's payout ratio on a per Common Share diluted basis was 75%.

The following table sets forth the amount of monthly cash distributions paid per Trust Unit by the Trust for the periods indicated.

	Distribution per Trust Unit
January 2008 – May 2008	$0.20
June 2008 – December 2008	$0.23
January 2009 – July 2009	$0.23

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
July 2009 – December 2009	$0.23
January 2010 – December 2010	$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 under the trading symbol "CPG". The following table sets forth the price range and trading volume of the Common Shares as reported by the TSX for the periods indicated.

	High ($)	Low ($)	Volume (000's)
2010			
January	39.70	37.68	18,956
February	39.44	37.06	13,039
March	39.50	38.44	14,917
April	43.58	39.04	17,272
May	43.69	37.28	23,199
June	40.21	37.10	18,932
July	38.50	35.90	18,544
August	38.50	35.30	20,708
September	38.00	36.43	23,218
October	41.33	37.91	21,210
November	41.56	39.91	17,270
December	45.60	41.44	22,229
2011			
January	44.89	42.13	27,905
February	46.98	42.60	15,585
March (1 - 23)	48.61	43.09	15,279

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 and Mr. Mark Eade, an officer of the Corporation, are each partners of McCarthy Tétrault LLP, a law firm that provides 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 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 Energy Services Ltd. 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	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 2001. 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 also served on the Board of Directors of Shelter Bay. Mr. Bannister is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and serves on the board of directors of Cequence Energy Ltd. and Surge Energy Inc. Formerly, he was a director of Mission Oil and Gas Inc., Breaker Energy, Impact Energy Inc., Boomerang Resources Ltd. and Laurasia Resources Ltd. Mr. Bannister holds a Bachelor of Science degree in geology.

External Auditor Services Fees

For services provided to the Corporation and its subsidiaries the years ended December 31, 2010 and 2009 PricewaterhouseCoopers LLP billed approximately $731,330 and $625,000, respectively, as detailed below:

	Year ended December 31	
	2010	**2009**
PricewaterhouseCoopers		
Audit fees	$ 490,250	$ 346,000
Audit-related fees[1]	$ 186,600	$ 240,600
Tax Fees	$ 38,480	$ 5,000
All other fees	$ 16,000	$ 33,400
Total	$ 731,330	$ 625,000

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 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.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Prior to the completion of the Shelter Bay Arrangement, the directors and executive officers as a group beneficially owned, directly or indirectly, or exercised control or direction over 6,402,356 common shares of Shelter Bay, representing approximately 0.8% of the issued and outstanding Shelter Bay common shares. See "*General Development of the Business of the Corporation – History*".

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 are agreements that may be considered material to us:

1. 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, 2010, 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.

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 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 31, 2010. 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, 2010.

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 Alberta Business Corporations Act 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:

   (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 generally accepted accounting principles ("GAAP"); 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 GAAP; 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). At least one Member of the Committee should have "accounting or related financial expertise" (i.e., the ability to analyze and interpret a full set of consolidated financial statements, including the notes attached thereto, in accordance with Canadian GAAP).

(c) The Board shall designate the Chairman of the Committee.

(d) 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 GAAP; 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.

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.

Meeting Agenda

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

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.

In Camera Meetings

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

Reporting to the Board

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next regular meeting.

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.

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.

2. Operating Procedures

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

A quorum shall be a majority of the Members.

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

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

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 GAAP 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 GAAP 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 GAAP 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 with External Auditors

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

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

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

(d) 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;

(e) 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;

(f) 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;

(g) 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;

(h) 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

(i) 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; and

(c) 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 procedure for the receipt and treatment of any complaint received by the Corporation regarding accounting, internal accounting controls or auditing 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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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, 2010, 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 - $MM)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	January 17, 2011	Canada	-	2,654	-	2,654
GLJ Petroleum Consultants	January 17, 2011	United States	-	14	-	14

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 14, 2011

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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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, 2010, 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 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 - $MM)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the P&NG Reserves of Crescent Point Energy Corp., As of December 31, 2010 prepared October 2010 to February 2011 GLJ Escalated Prices	Canada	Nil	6,498	Nil	6,498
		USA	Nil	5	Nil	5

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, Canada Dated March 8, 2011

ORIGINALLY SIGNED BY

Robert N. Johnson, P. Eng
Vice President, Engineering

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, 2010 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*"
SCOTT SAXBERG
President and Chief Executive Officer

"*C Neil Smith*"
C NEIL SMITH
Vice President, Engineering
and Business Development

"*Paul Colborne*"
PAUL COLBORNE
Director

"*Peter Bannister*"
PETER BANNISTER
Director

March 24, 2011