PINECREST ENERGY INC.

Annual Information Form

Year Ended December 31, 2010

March 23, 2011

TABLE OF CONTENTS

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, financial and business prospects and financial outlook, reserve and production estimates, expected levels of activity, budgeted capital expenditures and the method of funding thereof, drilling, completion and tie-in plans, productive capacity of wells, expected royalty rates and changes to the royalty regime and the possible effect thereof on Pinecrest Energy Inc. ("**Pinecrest**" or the "**Company**") may be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, estimated drilling costs of test wells and the timing thereof, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates and estimated production rates, changes in royalty rates and expenses, environmental risks, partner risk and competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, changes in the regulatory and taxation environment, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "*Risk Factors*" and elsewhere herein. The recovery and reserve estimates of Pinecrest's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such statements but which may prove to be incorrect. Although Pinecrest believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Pinecrest can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Pinecrest operates; the timely receipt of any required regulatory approvals; the ability of Pinecrest to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Pinecrest has an interest in to operate the field in a safe, efficient and effective manner; the ability of Pinecrest to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development of exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Pinecrest to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Pinecrest operates; and the ability of Pinecrest to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Pinecrest's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) and at Pinecrest's website (www.pinecrestenergy.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and the Company assumes no obligation to update or review them to reflect new events or circumstances except as required by applicable securities laws.

Forward-looking statements and other information contained herein concerning the oil and gas industry and the Company's general expectations concerning this industry is based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which the Company believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While the Company is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

NON-GAAP MEASURES

The Company uses the following terms for measurement within the MD&A that do not have a standardized prescribed meaning under Canadian generally accepted accounting principles ("**GAAP**") and these measurements may differ from other companies and accordingly may not be comparable to measures used by other companies. The terms "funds flow from operations", "funds flow from operations per share", "operating netback" and "corporate netback" in this MD&A are not recognized measures under GAAP. Management of the Company believes that these terms are useful, in addition to net earnings and cash flow from operating activities as defined by GAAP, for evaluating the Company's operating performance and leverage. Funds flow from operations is expressed as cash flow from operating activities before changes in non-cash working capital and asset retirement expenditures. Funds flow from operations per share is calculated using the weighted-average basic and diluted shares used in calculating earnings per share (see "Calculation of Cash Flow from Operations" below). Operating netback is a measure of operating margin used in capital allocation decisions. Pinecrest defines operating netback as average realized price per boe, less royalties per boe, less operating and transportation expenses per boe, plus any realized gain or loss per boe on financial instruments. Corporate netback is a measure of operating netback less general and administrative and interest expenses. Pinecrest defines corporate netback as operating netback plus other income per boe less general and administrative expenses per boe less interest expense per boe. ***Readers are cautioned that these measures should not be construed as an alternative to net earnings, or cash flow from operating activities as calculated under GAAP as an indication of the Company's performance.***

GLOSSARY

In this Annual Information Form, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta) together with any or all regulations promulgated thereunder, as amended from time to time;

"**Annual Information Form**" means this annual information form;

"**Antler Creek**" means Antler Creek Energy Corp., the previous name of the Company;

"**BEC**" means Batoche Energy Corp., a Corporation previously incorporated under the ABCA, now amalgamated with Antler Creek Energy Corp. to form Antler Creek Energy Corp;

"**BEC-G**" means Batoche Energy (Griffen) Corp, a Corporation incorporated under the ABCA, which assigned all of its assets to Antler Creek on June 1, 2009 and was dissolved on October 29, 2009;

"**BEC-H**" means Batoche Energy (Heward) Corp, a Corporation incorporated under the ABCA, which assigned all of its assets to Antler Creek on June 1, 2009 and was dissolved on October 29, 2009;

"**BEC-SPA**" means the agreement dated April 30, 2009 between Testudo and BEC, wherein Testudo agreed to purchase all of the issued and outstanding shares of BEC;

"**Board of Directors**" means the board of directors of the Company as it is comprised from time to time;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**CRA**" means Canada Revenue Agency;

"**Common Share**" or "**Common Shares**" means, respectively, one or more common shares in the capital of Pinecrest;

"**Company**" or "**Pinecrest**" means Pinecrest Energy Inc., a corporation amalgamated under the ABCA;

"**GAAP**" means Canadian generally accepted accounting principles;

"**Gross**" or "**gross**" means:

(a) in relation to the Company's interest in production and reserves which are the Company's working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest; and

(c) in relation to properties, the total area of properties in which the Company has an interest;

"**NAFTA**" means the North American Free Trade Agreement;

"**NEB**" means the National Energy Board;

"**Net**" or "**net**" means:

(d) in relation to the Company's interest in production and reserves, the Company's working interest (operating and non-operating) share after deduction of royalty obligations, plus the Company's royalty interests in production or reserves;

(e) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(f) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company;

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

"**NRF**" means the New Royalty Framework of the province of the Government of Alberta effective January 1, 2009;

"**Pinecrest**" or the "**Company**" means Pinecrest Energy Inc.;

"**Qualifying Transaction**" means a transaction where a capital pool company acquires by way of purchase, amalgamation, merger or arrangement with another company, one or more assets or businesses which, when purchased, optioned or otherwise acquired by the capital pool company together with any other concurrent transaction, would result in the capital pool company meeting the minimum listing requirements of the TSXV;

"**Sproule**" means Sproule & Associates Ltd.;

"**Sproule Report**" means report of Sproule dated March 11, 2011 evaluating the crude oil, natural gas liquids and natural gas reserves of the Company as at December 31, 2010;

"**Tax Act**" means the *Income Tax Act* (Canada) R.S.C. 1985, c.1 (5^{th} Supp.), as amended including the regulations thereunder;

"**Testudo**" means Testudo Oil & Gas Exploration Ltd., a Corporation incorporated under the ABCA, which subsequently amended its Articles of Incorporation to change its name to "Antler Creek Energy Corp." and which then amalgamated with Batoche to form Antler Creek; and

"**TSXV**" means the TSX Venture Exchange.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Company's most recently completed financial year, being December 31, 2010.

CONVENTIONS

Certain terms used herein are defined in the "*Glossary*". Unless otherwise indicated, references herein to "**$**" or "**dollars**" are to Canadian dollars. All financial information with respect to the Company has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

ABBREVIATIONS

Crude Oil and Natural Gas Liquids

Bbls	barrels
Bbls/d	barrels per day
Mbbls	thousand barrels
Boe	barrels of oil equivalent of natural gas (on the basis of 6 Mcf of natural gas to 1 bbl of oil)
Boe/d	barrels of oil equivalent per day
Mboe	thousand Boe
NGLs	natural gas liquids
Mmbtu	million British thermal units
Mstb	thousand stock tank barrels
Stb	stock tank barrel

Natural Gas

Bcf	billion cubic feet
Mcf	thousand cubic feet
Mmcf	million cubic feet
Mcf/d	thousand cubic feet per day
Mmcf/d	million cubic feet per day
GJ	gigajoule

Other

AECO	The natural gas storage facility located at Suffield, Alberta
LSD	Legal site description
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Disclosure provided herein in respect of Boe may be misleading, particularly if used in isolation. The Boe conversion ratio of 6 Mcf of natural gas to 1 bbl of oil used throughout this document is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSION

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
Thousand cubic metres	Mcf	35.494
Bbls	Cubic metres ("**m^3**")	0.159
Cubic metres	bbls	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471

THE COMPANY

Pinecrest is a junior oil and gas company involved in the exploration, development and production of oil and gas activities in Alberta and Saskatchewan.

The registered and head office of the Company are located at Suite 500, 255 - 5th Avenue SW, Calgary, Alberta T2P 3G6.

The Company does not have any subsidiaries. The Common Shares trade on the TSXV under the symbol "PRY".

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Company was originally incorporated under the ABCA on March 24, 2006 under the name "Testudo Oil & Gas Exploration Ltd." as a capital pool company. On May 22, 2009, the Company amended its articles of incorporation to change its name to "Antler Creek Energy Corp."

Batoche Energy Corp. was incorporated under the ABCA on October 18, 2006. Batoche Energy (Griffen) Corp. ("**BEC-G**") and Batoche Energy (Heward) Corp. ("**BEC-H**"), both wholly-owned subsidiaries of BEC, were incorporated under the ABCA on December 19, 2007 and January 24, 2008, respectively.

On May 31, 2009, Antler Creek Energy Corp. and BEC amalgamated and continued under the name Antler Creek Energy Corp. Following the amalgamation, steps were taken to wind-up both of BEC's wholly-owned subsidiaries, BEC-G and BEC-H and dissolution of both occurred on October 29, 2009.

On May 6, 2010, Antler Creek completed the Capitalization Transaction (as defined herein), and on July 22, 2010 at an annual and special meeting of shareholders the Company amended its articles to change its name to "**Pinecrest Energy Inc.**"

The following is a summary of the significant events in the development of the Company for the specific periods shown.

Year Ended July 31, 2008

During the year ended July 31, 2008, the Company did not acquire any assets and as such held no assets, except for cash. The Company's only income was interest income.

At the end of the fiscal period, the Company made an offer to acquire certain oil and gas assets from BEC-G and other companies. The Company continued to pursue these opportunities with a view to completing its Qualifying Transaction.

Year Ended July 31, 2009

On September 25, 2008, the Company entered into a definitive agreement ("**BEC Asset Sale Agreement**") with BEC, its wholly-owned subsidiary, BEC-G, and fourteen other legal entities (the "**Beneficial Owners**"). The BEC Asset Sale Agreement was amended on October 16, 2008 and October 30, 2008. The amended agreement provided that the Company would purchase a ten percent (10%) working interest in Section 13-8-11-W2M from Batoche Energy (Griffen) Corp. and a 10% working interest in certain lands in Griffin, Saskatchewan from BEC. The consideration to be paid by the Company for the BEC-G and Batoche Energy Corp. working interest was an aggregate of $1,200,000 plus GST (the "**BEC Asset Purchase Price**").

On April 30, 2009 the Company entered into the BEC-SPA, which superseded and replaced in its entirety the BEC Asset Sale Agreement. The purchase price for the purchase of the BEC common shares was $2,100,000. Following closing of the BEC-SPA Financing (as defined below), the Company completed its Qualifying Transaction.

The BEC-SPA Financing was completed on May 25, 2009 with the sale of 603,666 Common Shares on a "flow-through" basis under the Tax Act ("**Flow-Through Shares**") at a price of $0.45 per Flow-Through Share and 748,334 units of Antler Creek at a price of $0.45, with each unit comprised of one Common Share and one Common Share purchase warrant (a "**Warrant**") (the "**BEC-SPA Financing**"). The Company agreed to renounce $271,650 to the holders of Flow-Through Shares no later than December 31, 2009.

The acquisition of the shares of BEC constituted a significant acquisition for the Company. For further information on the acquisition of BEC, please refer to the business acquisition report dated May 6, 2010, a copy of which can be found on the Company's SEDAR profile at www.sedar.com.

On May 31, 2009, the Company and BEC amalgamated and carried on under the name "Antler Creek Energy Corp." Following the amalgamation, on June 1, 2009 the assets of each subsidiary were assigned to the parent and steps were taken to wind-up BEC-G and BEC-H, and dissolution of each was effected on October 29, 2009.

Year Ended July 31, 2010

Capitalization Transaction

On April 25, 2010, the Company entered into a definitive capitalization and investment agreement (the "**Capitalization Agreement**") with an investor group including Wade Becker, Dan Toews, Bill Turko and Korby Zimmerman (the "**Initial Investor Group**"), which provided for the non-brokered private placement of up to gross proceeds of approximately $20 million (the "**Private Placement**") and the appointment of a new management team (the "**New Management Team**") and a new Board of Directors. The transactions contemplated by the Capitalization Agreement are referred to collectively in this Annual Information Form as the "**Capitalization Transaction**". The Capitalization Transaction closed in successive closings effective May 6, 2010 and May 21, 2010, respectively, with the Company issuing a total of 23,613,810 Common Shares and 34,258,530 common share purchase warrants ("**Purchase Warrants**") amounting to aggregate gross proceeds of approximately $20 million. Each Purchase Warrant entitles the holder to purchase one Common Share at an exercise price of $0.50 over the next five years subject to certain Common Share performance criteria being satisfied.

Each person who became a director or officer of Pinecrest following completion of the Capitalization Transaction and who subscribed for securities thereunder entered into an escrow agreement (the "**Escrow Agreement**") which provides that the 29,428,530 Common Shares, the Purchase Warrants and any Common Shares issued on exercise of the Purchase Warrants (as the case may be) are subject to a 24 month escrow wherein 25% of such securities shall be released on each of the 6, 12, 18 and 24 month anniversaries of closing of the respective tranche of the Private Placement. There are currently 22,071,403 Common Shares and 22,071,403 Purchase Warrants subject to escrow under the Escrow Agreement.

Annual and Special Meeting of Shareholders

On July 21, 2010, the Company held an annual and special meeting of shareholders at which shareholders approved, among other items, (i) the adoption of new by-laws of the Company, (ii) a change of corporate name from "Antler Creek Energy Corp." to "Pinecrest Energy Inc.", and (iii) the consolidation of the issued and outstanding Common Shares on an up to ten (10) for one (1) basis (the "**Consolidation**").

The Company filed articles of amendment changing the corporate name to "Pinecrest Energy Inc." effective July 22, 2010. As at the date hereof, the Consolidation has not been implemented.

Asset Acquisitions

On July 14, 2010 and July 15, 2010, the Company acquired certain assets for aggregate purchase price of $18.1 million (including closing adjustments), all of which are located in the Company's greater Red Earth core focus area (collectively, the "**Acquisition**"). In total, the Company acquired 21,627 gross acres (13,150 net) of land located in the heart of the emerging Slave Point formation light oil resource play. The assets provide over 50 net low risk Slave Point horizontal drilling locations along with approximately 70 Bbls/d of light oil production and associated producing infrastructure. On August 30, 2010 the Company filed a business acquisition report describing the Acquisition as this transaction constituted a "significant acquisition" under National Instrument 51-102 – *Continuous Disclosure Obligations*. The business acquisition report can be viewed on the Company's SEDAR profile at www.sedar.com.

July Offering

On July 7, 2010, the Company issued an aggregate of 24,050,000 Common Shares at a price of $1.04 per Common Share for aggregate proceeds of $25,012,000 by way of short form prospectus, through a syndicate of underwriters. The underwriters exercised their over-allotment option and on July 9, 2010, the Company issued an additional 3,607,500 Common Shares at a price of $1.04 per share for aggregate gross proceeds of $3,751,800.

Year Ended December 31, 2010

September Offering

On September 15, 2010, the Company issued an aggregate of 25,000,000 Common Shares at a price of $1.40 per Common Share for aggregate proceeds of $35,000,000 by way of short form prospectus through a syndicate of underwriters. The Company also granted the underwriters an over-allotment option to purchase up to an additional 3,750,000 Common Shares at a price of $1.40 per share on the same terms and conditions, exercisable at any time, in whole or in part for a period of 30 days following closing. As a partial exercise of the over-allotment option, the Company issued an additional 3,663,143 common shares at a price of $1.40 per share for aggregate proceeds of $5,128,400 on October 12, 2010.

Credit Facility

On October 26, 2010, the Company entered into a demand operating credit facility in the amount of $30,000,000 with a Canadian chartered bank. The facility is secured by a floating charge debenture of $50,000,000 and a general security interest in all of the present and future acquired property, bearing interest at prime plus 2%. At December 31, 2010 the Company had no balance outstanding. This facility expires on April 26, 2011 and at that time, the Company will determine its future capital requirements.

Change of Year End

On October 16, 2010, Pinecrest received approval from the Canada Revenue Agency and subsequently, on November 25, 2010, Pinecrest filed a notice under Part 4.8 of *National Instrument 51-102 – Continuous Disclosure Obligations* providing for the change of the Company's financial year end from July 31 to December 31.

November Offering

Effective November 16, 2010, the Company issued a total of 55,660,000 Common Shares at a price of $1.55 per Common Share for aggregate proceeds of $86,273,000 by way of short form prospectus through a syndicate of underwriters.

GENERAL DESCRIPTION OF THE BUSINESS

Pinecrest's business plan is to focus on sustainable and profitable per share growth in both cash flow from operating activities and net asset value. The Company's key strategies are to:

(a) focus on oil production and reserves from a large operated land base and a portfolio of drilling locations based on Pinecrest's use of seismic data and geological reports;

(b) exploit the low risk development drilling opportunities where the Company has existing infrastructure; and

(c) seek acquisitions consistent with this strategic focus and in areas where the management team has experience and expertise.

Price Risk Management

Prices received for production and associated operating expenses are impacted in varying degrees by factors outside management's control. These factors include, but are not limited to, the following:

- World market forces, including the ability of OPEC to set limits and maintain production levels and prices for crude oil;
- Political conditions, including the risk of hostilities in the Middle East and other regions throughout the world;
- Increases or decreases in crude oil quality and market differentials;
- Impact of changes in the exchange rate between Canada and US dollars on prices received by the Company for its crude oil and natural gas;
- North American market forces, most notably shifts in the balance between supply and demand for the crude oil and natural gas and the implications for the price of crude oil and natural gas;
- Global and domestic weather conditions;
- Price and availability of alternative fuels; and
- The effect of energy conservation measures and government regulation.

Revenue Sources

For the year ended December 31, 2010, 98% of the revenue (before royalties) from the Company's properties was derived from crude oil and 2% was derived from natural gas and natural gas liquids.

Seasonal Considerations

All of the Company's properties are accessible year round, except during spring break up. Major facilities through which the Company's production is processed may temporarily be shut down for short periods of time during the year to conduct repair and maintenance operations.

Environmental Matters

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal regulations. Compliance with such regulation can require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and imposition of material fines and penalties, all of which might have a significant negative impact on earnings and overall competitiveness.

The operations of the Company are, and will continue to be affected in varying degrees by laws and regulations regarding environmental protection. The Company is committed to meeting its responsibilities to protect the environment and the Company will take such steps as required to ensure compliance with environmental legislation in all jurisdictions in which it operates. The Company believes that it is reasonably likely that the trends towards stricter standards in environmental legislation and regulation will continue and anticipates making increased expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment. However, it is not currently possible to quantify any such increased expenditures and it is not anticipated that the Company's competitive position will be adversely affected by current or future environmental laws and regulations governing its oil and natural gas operations.

Competition

There is strong competition relating to all aspects of the oil and natural gas industry. The Company actively competes for capital, skilled personnel, undeveloped lands, reserve acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity, and in all other aspects of its operations with a substantial number of other organizations, many of which have greater technical and financial resources than the Company. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world wide basis and have greater and more diverse resources upon which to draw.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 23, 2011 and the effective date of the Statement is December 31, 2010.

Disclosure of Reserves Data and Other Information

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2010 contained in the Sproule Report. The Reserves Data summarizes the crude oil, natural gas liquids and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. The Company engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of the Company's reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan.

The Report of Management and Directors on Oil and Gas Disclosure and the Report on Reserves Data by the Independent Qualified Reserves Evaluator are attached as Schedules "A" and "B" hereto, respectively.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Company's crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

	RESERVES [1]									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS[2]		NATURAL GAS LIQUIDS		BARRELS OF OIL EQUIVALENT[3]	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mmcf)	Net (Mmcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
Proved Developed										
Producing	679.4	585.0	-	-	171	147	18.8	14.3	726.8	623.8
Non-Producing	160.7	137.1	-	-	26	24	5.1	4.0	170.2	145.2
Proved Undeveloped	196.3	160.7	-	-	42	32	6.5	5.1	209.8	171.2
TOTAL PROVED	1,036.4	882.8	-	-	239	204	30.4	23.4	1,106.7	940.2
Probable	674.2	565.5	-	-	88	75	10.8	8.4	699.8	586.5
TOTAL PROVED PLUS PROBABLE	1,710.6	1,448.4	-	-	327	279	41.2	31.7	1,806.4	1,526.6

Notes:

(1) Numbers in this table are subject to round off error.
(2) Natural gas volumes include solution gas volumes associated with the Company's light and medium crude oil reserves.
(3) Natural gas is converted Boe's at a ratio of six thousand standard cubic feet to one barrel of oil.

	NET PRESENT VALUES OF FUTURE NET REVENUE[1][2][3]									
	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)	0 (M$)	5 (M$)	10 (M$)	15 (M$)	20 (M$)
Proved Developed										
Producing	35,829	29,406	25,191	22,222	20,018	35,829	29,406	25,191	22,222	20,018
Non-Producing	9,440	7,870	6,886	6,200	5,686	9,440	7,870	6,886	6,200	5,686
Proved Undeveloped	8,425	6,618	5,399	4,526	3,872	8,425	6,618	5,399	4,526	3,872
TOTAL PROVED	53,694	43,894	37,475	32,948	29,576	53,694	43,894	37,475	32,948	29,576
Probable	37,386	24,812	18,472	14,720	12,248	37,386	24,812	18,472	14,720	12,248
TOTAL PROVED PLUS PROBABLE	91,080	68,706	55,947	47,668	41,825	91,080	68,706	55,947	47,668	41,825

Notes:

(1) Numbers in this table are subject to round off error.
(2) Natural gas volumes include solution gas volumes associated with the Company's light and medium crude oil reserves.
(3) Natural gas is converted Boe's at a ratio of six thousand standard cubic feet to one barrel of oil.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)	INCOME TAXES (M$)	FUTURE NET REVENUE AFTER INCOME TAXES (M$)
Proved Reserves	103,945	15,760	30,112	3,177	1,201	53,694	-	53,694
Proved Plus Probable Reserves	176,455	27,448	50,214	6,285	1,428	91,080	-	91,080

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	37,475	$39.86/Boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	-	$0/Mcf
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	55,947	$36.65/Boe
	Natural Gas (including by-products but excluding solution gas from oil wells)	-	$0/Mcf

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the Sproule Report are based on the definitions and guidelines contained in NI 51-101 and the COGE Handbook. A summary of those definitions are set forth below.

   Reserve Categories

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on:

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions, specifically the forecast prices and costs.

Reserves are classified according to the degree of certainty associated with the estimates:

(a) **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.

(b) **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.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(c) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

   (i) **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.

   (ii) **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.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, 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 classification (proved, probable) 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 subdivide 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.

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 reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable reserves.

A qualitative 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 clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Forecast Costs and Price Assumptions

The forecast cost and price assumptions assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing**,** inflation and exchange rates utilized by Sproule in the Sproule Report were Sproule's forecasts, as at December 31, 2010, as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

	OIL							
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Oil Price 40° API ($Cdn/Bbl)	Cromer Medium 29.3° API ($Cdn/Bbl)	Natural Gas[(1)] AECO Gas Price ($Cdn/MMMBtu)	Pentanes Plus FOB Field Gate ($Cdn/Bbl)	Butane F.O.B. Field Gate ($Cdn/Bbl)	Inflation Rates[(2)] %/Year	Exchange Rate[(3)] ($US/$Cdn)
Forecast								
2011	$88.40	$93.08	$85.63	$4.04	$95.32	$62.44	1.5%	$0.932
2012	$89.14	$93.85	$86.34	$4.66	$96.11	$62.95	1.5%	$0.932
2013	$88.77	$93.43	$85.02	$4.99	$95.68	$62.67	1.5%	$0.932
2014	$88.88	$93.54	$84.18	$6.58	$95.79	$62.75	1.5%	$0.932
2015	$90.22	$94.95	$85.45	$6.69	$97.24	$63.79	1.5%	$0.932
2016	Escalated oil, gas and product prices at approximately 1.5% per year thereafter							

Notes:

(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical price realized by Pinecrest for the year ended December 31, 2010 was $78.13/bbl for crude oil and NGLs and $4.05/Mcf for natural gas.

Estimated future abandonment costs related to a working interest have been taken into account by Sproule in determining reserves that should be attributed to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated future well abandonment costs. No allowance was made, however, for reclamation of wellsites or the abandonment of any facilities.

The forecast price and cost assumptions assume the continuance of current laws and regulations.

The extent and character of all factual data supplied to Sproule were accepted by Sproule as represented. No field inspection was conducted.

The impact of the optional Transitional Royalty Rate ("**TRR**") (announced by the Government of Alberta on November 19, 2008) was considered in forecasts of future drilling in Alberta and taken into account in the above calculations of future net revenue. In the calculation of future net revenue, the Company was assumed to opt for TRR on new wells where justified by a comparison of economics under TRR and the NRF. The effects of the short term incentive program announced by the Government of Alberta on March 3, 2009 were not included or considered in the calculation of reserves and future net revenue. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*".

Reconciliation of Changes in Reserves and Future Gross Revenue

The following sets out the reconciliation of Pinecrest's gross reserves based on forecast prices and costs by principal product type:

RECONCILIATION OF
COMPANY GROSS[1] RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (Mmcfl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
July 31, 2010[2]	311.8	336.3	648.1	65	88	153	10.5	14.0	24.5
Extensions	243.5	312.7	556.2	22	3	25	4.5	0.7	5.2
Technical Revisions & Economic Factors	195.4	(98.1)	97.3	61	(40)	21	9.7	(6.7)	3.0
Infill	11.3	5.6	16.9	6	3	9	0.9	0.5	1.4
Acquisitions	298.0	117.7	415.7	89	34	123	5.3	2.3	7.6
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(23.6)	-	(23.6)	(4)	-	(4)	(0.5)	-	(0.5)
December 31, 2010	1,036.4	674.2	1,710.6	239	88	327	30.4	10.8	41.2

Note:

(1) Gross Reserves means the Company`s working interest reserves before calculation of royalties, and before consideration of the Company`s royalty interests.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Pinecrest's assets for the years ended December 31, 2010 and July 31, 2010, July 31, 2009 and from April 1, 2009 (inception) and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End[(1)]	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
April 1, 2009	-	-	-	-	-	-	-	-
July 31, 2009	67.0	67.0	-	-	-	-	-	-
July 31, 2010	97.5	97.5	-	-	33.0	33.0	5.2	5.2
December 31, 2010	98.8	196.3	-	-	9.0	42.0	1.3	6.5

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
April 1, 2009	56.3	56.3	-	-	-	-	-	-
July 31, 2009	295.6	295.6	-	-	-	-	-	-
July 31, 2010	217.3	217.3	-	-	73.0	73.0	11.7	11.7
December 31, 2010	206.1	299.7	-	-	9	16	1.4	2.5

Note:

(1) Cumulative at year end is cumulative of previous year plus first attributed less developed during the year.

In general, once proved and/or probable undeveloped reserves are identified they are scheduled into Pinecrest's development plans. The Company plans to develop its proved and probable undeveloped reserves within two years. A number of factors that could result in delayed or cancelled development are as follows:

- changing economic conditions (due to pricing, operating and capital expenditure fluctuations);
- changing technical conditions (production anomalies - such as water breakthrough or accelerated depletion);
- multi-zone developments (such as a prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to the Company in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and
- surface access issues (landowners, weather conditions, regulatory approvals).

Significant Factors or Uncertainties

The process of evaluating reserves is inherently 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 and other factors and assumptions that may affect the reserve estimates and the present worth of the future net revenue therefrom. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates 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 government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance and geologic conditions or production. These revisions can be either positive or negative.

The Company does not anticipate any unusually high development costs or operating costs, the need to build a major pipeline or other major facility before production of reserves can begin, or contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations.

Future Development Costs

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted below:

	Forecast Prices and Costs (M$)	
Year	Proved Reserves	Proved Plus Probable Reserves
2011	2,903	5,874
2012	274	411
2013	-	
2014	-	-
2015	-	-
Thereafter	-	-
Total Undiscounted	3,177	6,285

The future development costs are capital expenditures required in the future for Pinecrest to convert proved undeveloped reserves and probable reserves to proved developed producing reserves. The undiscounted development costs are $3.177 million for proved reserves and $6.285 million for proved plus probable reserves (in each case based on forecast prices and costs).

On an ongoing basis, Pinecrest will use internally generated cash flow from operations, debt and new equity issues, if available on favourable terms, to finance its capital expenditure program. The cost of funding is not expected to have any effect on disclosed reserves or future net revenue nor make the development of a property uneconomic for the Company.

Other Oil and Gas Information

Principal Properties

Pinecrest has 2 core areas, Greater Red Earth, Alberta and southeast Saskatchewan, all of which are reviewed in the Sproule Report.

The following is a description of Pinecrest's principal oil and gas properties as at December 31, 2010.

Evi/Otter Properties

The Evi/Otter Properties are located in northern Alberta in townships 86-88, ranges 10-12 west of the fifth meridian. The Evi/Otter Properties consist of 68 gross (21.8 net) oil wells, 14 of which are Pinecrest operated. Of these gross wells, 39 are currently producing (3 Pinecrest operated); 21 from the Slave Point formation, 15 from the Granite Wash formation and 3 from commingled Slave Point and Granite Wash. Canadian Forest Oil Ltd. operates most of the production in this area as well as the 11-4-87-11W5M central battery (Pinecrest owns a 30% working interest in the battery). Field production is either gathered via effluent flowlines to the 11-4-87-11W5 battery or is trucked from single well batteries to the central battery where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Evi/Otter properties for the year ended December 31, 2010 averaged 39.6 boe/d net, 92% of which is light sweet crude oil. For the year ended December 31, 2010, Pinecrest drilled six gross (2.40 net) wells in the Evi/Otter area, three (1.92 net) of which were company operated. These wells will be placed on production in early 2011.

Red Earth Properties

The Red Earth Properties are located in northern Alberta in townships 87-89, ranges 7-8 west of the fifth meridian. The Red Earth Properties consist of 21 gross (13.8 net) oil wells, 12 of which are Pinecrest operated. Of these gross wells, 11 are currently producing (7 Pinecrest operated); 5 from the Slave Point formation, 3 from the Granite Wash formation and 3 from commingled Slave Point and Granite Wash. Field production is either gathered via effluent flowlines to third party processing facilities or is trucked from single well batteries to either Pinecrest's Ogston battery located in 10-32-89-11W5M or to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Red Earth properties for the year ended December 31, 2010 averaged 24.5 bbls/d net, 100% of which is light sweet crude oil. For the year ended December 31, 2010, Pinecrest did not drill any wells in the Red Earth area.

Loon Properties

The Loon Properties are located in northern Alberta in townships 84-86, ranges 8-9 west of the fifth meridian. The Loon Properties consist of 16 gross (7.0 net) oil wells, 4 of which are Pinecrest operated. Of these gross wells, 9 are currently producing; 7 from the Slave Point formation, 2 from the Granite Wash formation. Field production is either gathered via effluent flowlines to third party processing facilities or is trucked from single well batteries to either Pinecrest's Ogston battery located in 10-32-89-11W5M or to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Loon Properties for the year ended December 31, 2010 averaged 40 Bbls/d net, 100% of which is light sweet crude oil. For the year ended December 31, 2010, Pinecrest drilled one gross (0.45 net) partner operated well in the Loon area. This well will be placed on production in early 2011.

Ogston Properties

The Ogston Properties are located in northern Alberta in townships 89-90, ranges 10-11 west of the fifth meridian. The Ogston Properties consist of 17 gross (10.7 net) oil wells, 14 of which are Pinecrest operated. Of these gross wells, 7 are currently producing, all from the Granite Wash formation. Field production is gathered via effluent flowlines to the Pinecrest operated 10-32-89-11W5 central battery where oil and water are separated, water is disposed of and oil is trucked to sales.

Production from the Ogston Properties for the year ended December 31, 2010 averaged 8.9 Bbls/d net, 100% is light sweet crude oil (solution gas is not conserved). For the year ended December 31, 2010, Pinecrest did not drill any wells in the Ogston area.

Viewfield Properties

The Viewfield Properties are located in southeast Saskatchewan, approximately 130 kilometres southeast of the city of Regina, in townships 8-10, ranges 9-11 west of the second meridian. The Viewfield Properties consist of 14 gross (5.5 net) oil wells, 9 of which are currently producing (with 3 more commencing production in the first quarter of 2011). Pinecrest operates 6 of the 14 wells in this area. All but 2 wells are horizontally drilled targeting the Bakken formation and all of the horizontal wells have been completed using multi-stage fracturing technology. Field production is either gathered via effluent flowlines to third party processing facilities or is trucked from single well batteries to third party processing facilities where oil and water are separated, water is disposed of and oil is shipped to sales.

Production from the Viewfield properties for the year ended December 31, 2010 averaged 49.3 boe/d net, 90% of which is light crude oil. For the year ended December 31, 2010, Pinecrest drilled four gross (2.25 net) company operated wells in the Viewfield area. One (0.38 net) well was placed on production in late December 2010 and the remaining wells will be placed on production in early 2011.

Oil and Gas Wells

The following table sets forth the number and status of wells in which the Company had a working interest as at December 31, 2010:

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing[3]		Producing		Non-Producing[1]	
	Gross[1]	Net[2]	Gross	Net	Gross	Net	Gross	Net
Alberta	102.0	29.3	49.0	23.7	-	-	1.0	0.3
Saskatchewan	9.0	2.1	5.0	3.4	-	-	-	-
Total	111.0	31.4	54.0	27.1	-	-	1.0	0.3

Note:

(1) Gross means number of wells in which Pinecrest has a working interest.
(2) Net means the aggregate number of wells obtained by multiplying Pinecrest's working interest percentage held therein.
(3) All non-producing oil and natural gas wells are located near existing infrastructure.

Properties with No Attributable Reserves

At December 31, 2010 the Company had 48,450 gross (40,309 net) acres of undeveloped land holdings, consisting of 44,674 gross (38,010 net) acres in the Province of Alberta and 3,777 gross (2,238 net) acres in the Province of Saskatchewan. The Company expects that rights to 614 net acres of its undeveloped land holdings will expire by December 31, 2011.

Forward Contracts and Marketing

As of the date hereof, the Company does not have any forward contracts.

Additional Information Concerning Abandonment Costs

Pinecrest estimates well abandonment costs on an area by area basis using historical costs and supplemented by current industry costs and changes in regulatory requirements. If representative comparisons are not readily available, an estimate is prepared based on the various regulatory abandonment requirements. The Company has 166 gross (58.8 net) well events for which it expects to incur abandonment costs.

Estimated costs of abandonment were included in the Sproule Report as a deduction in determining future net revenue. The total estimated abandonment costs in respect of proved reserves using forecast prices is $1,201 million undiscounted ($0.382 million using a 10% discount rate). The full amount of such values were deducted as abandonment costs in estimating future net revenue of the Company in respect of proved reserves as disclosed above. No allowance for salvage value was included in these costs. The total proved plus probable abandonment and reclamation costs are $1.428 million undiscounted and $0.303 million (discounted at 10%). The table below indicates the expected timing of well abandonment costs for the Company.

The following table sets forth abandonment costs deducted in the estimation of the Company's future net revenue:

Forecast Prices and Costs (Total Proved) ($000s)

Year	Abandonment Costs (Undiscounted)
December 31, 2011	16
December 31, 2012	-
December 31, 2013	46
Thereafter	1,139
Total Undiscounted	1,201
Total Discounted @ 10%	382

Forecast Prices and Costs (Total Proved plus Probable) ($000s)

Year	Abandonment Costs (Undiscounted)
December 31, 2011	-
December 31, 2012	16
December 31, 2013	15
Thereafter	1,397
Total Undiscounted	1,428
Total Discounted @ 10%	303

Tax Horizon

Based on the Company's available tax pools, expected capital expenditures and forecast net income for 2010, the Company does not anticipate paying current income taxes in 2011. Depending on levels of production, commodity prices, acquisitions and capital expenditures, Pinecrest may begin paying current income taxes in 2011 or beyond.

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2010:

Property acquisition costs	
Proved properties	$17,280,421
Undeveloped properties	56,466,481
Exploration costs	145,391
Development costs	13,285,561
Total	87,177,854

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which the Company participated during the year ended December 31, 2010:

	Exploration		Development	
	Gross	Net	Gross	Net
Light and Medium Oil	-	-	11.0	5.1
Heavy Oil	-	-	-	-
Natural Gas	-	-	-	-
Service	-	-	-	-
Dry	-	-	-	-
Total:	-	-	11.0	5.1

See "*Principal Properties*" for a description of the Company's exploration and development during the year ended December 31, 2010.

Production Estimates

The following table discloses the volume of Pinecrest's working interest share of production estimated before the deduction of royalties, for gross proved reserves and gross probable reserves as reported in the Sproule Report effective December 31, 2010 based on forecast prices and costs.

Forecast Prices and Costs

Total Proved

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Red Earth	389	61	8	407
Viewfield	186	96	15	217
Total Proved	575	157	23	624

Total Proved Plus Probable

	Light and Medium Oil *(Bbls/d)*	Natural Gas *(Mcf/d)*	Natural Gas Liquids *(Bbls/d)*	Boe *(Boe/d)*
Red Earth	536	62	8	554
Viewfield	200	103	16	233
Total Proved plus Probable	736	165	24	787

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

	Quarter Ended					
	Dec. 31, 2010	Sep. 30, 2010	Jul 31, 2010	Apr. 30, 2010	Jan. 31, 2010	Oct. 31, 2009
Number of producing days	92	61	92	89	92	92
Average Daily Production[1]						
Light and Medium Crude Oil (Bbls/d)	183	111	71	26	50	24
Heavy Oil (Bbls/d)	-	-	-	-	-	-
Gas (Mcf/d)	32	23	20	9	4	4
NGLs (Bbls/d)	2	4	4	1	1	1
Combined (Boe/d)	190	119	78	27	52	25
Average Price Received						
Light and Medium Crude Oil ($/Bbl)	80.88	74.01	82.12	79.73	63.87	72.06
Heavy Oil ($/Bbls)	-	-	-	-	-	-
Gas ($/Mcf)	4.19	3.75	4.62	4.93	5.32	4.29
NGLs ($/Bbls)	46.21	50.93	49.59	54.98	58.19	47.92
Combined ($/Boe)	78.54	71.57	78.24	76.37	63.36	70.41
Royalties Paid						
Light and Medium Crude Oil ($/Bbl)	14.03	6.05	8.99	12.97	9.52	7.76
Heavy Oil ($/Bbls)	-	-	-	-	-	-
Gas ($/Mcf)	0.40	0.34	0.48	0.46	0.48	0.38
NGLs ($/Bbls)	8.98	4.85	5.27	5.50	5.88	4.76
Combined ($/Boe)	13.64	5.88	8.56	12.20	9.38	7.56
Operating & Transportation Expenses ($/Boe)	16.32	22.86	18.54	21.46	12.92	27.07
Netback Received ($/Boe)[2]	48.58	42.83	51.14	42.71	41.06	35.78

Notes:

(1) Before deduction of royalties.
(2) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table indicates the Company's average daily production from its important fields for the year ended December 31, 2010:

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Gas (Mcf/d)	NGLS (Bbls/d)	Boe (Boe/d)
Red Earth	110.0	-	14.3	0.6	113.0
Viewfield	44.5	-	14.3	2.4	49.0
Total	154.5	-	28.6	3.0	162.0

The Company's production for the year ended December 31, 2010 was 96% light and medium crude oil, 4% natural gas, and 0% heavy oil.

For the twelve months ended December 31, 2010, approximately 96% of the Company's gross revenue was derived from light and medium oil production and the remaining 4% of the Company's gross revenue was derived from natural gas and natural gas liquids production.

DIRECTORS AND OFFICERS OF THE COMPANY

The name, province and country of residence, and position held with the Company of each of the directors and officers of the Company are as follows:

Name, Province and Country of Residence	Position Presently Held	Director/Officer Since	Common Shares Beneficially Owned or Controlled or Directed, Directly or Indirectly
Wade Becker Alberta, Canada	President, Chief Executive Officer and a Director	May 7, 2010	4,167,849 (2.45%)
Korby Zimmerman Alberta, Canada	Vice President, Business Development and Land and a Director	May 7, 2010	4,207,848 (2.48%)
John Brussa(2)(3) Alberta, Canada	Director	May 7,2010	1,150,000 (0.68%)
David Fitzpatrick(1)(2)(3) Alberta, Canada	Director	May 7, 2010	1,200,000 (0.71%)
David Johnson(1)(3) Alberta, Canada	Director	May 7, 2010	1,261,400 (0.74%)
Rob Zakresky(1)(2) Alberta, Canada	Director	May 7, 2010	850,000 (0.50%)
Brent Gough Alberta, Canada	Vice President, Operations	May 7, 2010	4,027,849 (2.37%)
Joe Sobochan Alberta, Canada	Vice President, Geology	October 6, 2010	1,369,514 (0.81%)
Dan Toews Alberta, Canada	Vice President, Finance & Chief Financial Officer	May 7, 2010	4,248,949 (2.50%)
Bill Turko Alberta, Canada	Vice President, Engineering	May 7, 2010	4,114,514 (2.42%)
Jay Reid Alberta, Canada	Corporate Secretary	May 7, 2010	300,000 (0.18%)

Notes:

(1) Member of the Audit Committee.
(2) Member of Corporate Governance, Compensation and Nominating Committee.
(3) Member of the Reserves Committee.
(4) The Company does not have an Executive Committee.

As of the date hereof, the directors and officers of the Company beneficially own or control or direct, directly or indirectly, 26,897,923 Common Shares, being approximately 15.8% of the issued and outstanding Common Shares.

Wade Becker, President and Chief Executive Officer and a Director

Wade Becker has extensive experience in leadership roles at public oil and gas companies. Mr. Becker was President, Chief Executive Officer and Director at Peerless Energy Inc. ("Peerless"). Previously Mr. Becker was Vice President, Land and co-founder of both Crescent Point Energy Trust and its predecessor Crescent Point Energy Ltd. Mr. Becker has over 18 years experience in the oil and gas industry.

Korby Zimmerman, Vice President, Business Development and Land and a Director

Korby Zimmerman brings over 18 years oil and gas experience specializing in land and acquisition negotiations. Previously Mr. Zimmerman was Group Leader at EnCana Corporation. Prior to that he was Vice President, Land and Business Development at Ketch Energy Trust.

John Brussa, Director

Mr. Brussa is a partner of Burnet, Duckworth & Palmer LLP since 1987 and is presently the head of its Tax Department. Mr. Brussa currently serves as a director of a number of publicly listed resource Companies and several non-profit or charitable organizations.

David Fitzpatrick, Director

Mr. Fitzpatrick is currently an independent businessman. From 1996 to 2007 Mr. Fitzpatrick was the President, CEO and Director of Shiningbank Energy Ltd. (acquired by PrimeWest Energy Trust ("PrimeWest"), an oil and gas royalty trust). Mr. Fitzpatrick serves or has served as a Director of Compton Petroleum Corporation, PrimeWest, Shiningbank Energy Income Fund Inc., Platform Energy and Twin Butte Energy Ltd., each of which is or was an oil and gas company or trust.

David D. Johnson, Director

Mr. David D. Johnson is currently the Chairman of Progress Energy Resources Corp. which was formed in 2009. From 2004 to 2009, Mr. Johnson served as the Chairman of Progress Energy Trust. Mr. Johnson was the President and Chief Executive Officer of Pro-Ex from July 2004 to January 2009. Mr. Johnson was the President and Chief Executive Officer of Progress Energy Ltd. from November 2001 to July 2004 and the President and Chief Executive Officer of Encal Energy Ltd. from July 1994 to April 2001. Mr. Johnson has over 30 years of diverse experience in the oil and gas industry including a background in production, reservoir evaluation and operations. He has a B.Sc. in Petroleum Engineering, is a member of the Association of Engineers, Geologists and Geophysics of Alberta and has served twice as a governor of the Canadian Association of Petroleum Producers.

Rob Zakresky, Director

Mr. Zakresky has held the position of President and Chief Executive Officer of Crocotta Energy Inc. since November 2006. From 1993 to October 2006, Mr. Zakresky has sequentially held the position of President, Chief Executive Officer and a director of Bellator Exploration Inc., Viracocha Energy Inc., Chamaelo Energy Inc. and Chamaelo Exploration Ltd. Mr. Zakresky was a director of Peerless.

Brent Gough, Vice President, Operations

Brent Gough is a professional Engineer with over 29 years of experience in the oil and gas industry. Mr. Gough was the President of several private oil and gas companies as well as several private flow-through drilling funds. Prior to that, he was Vice President, Engineering at Edge Energy.

Joe Sobochan, Vice President, Geology

Mr. Sobochan has over 20 years of exploration and development experience in Western Canada that has included employment with PetroBakken Energy Ltd., Peerless Energy Inc., StarPoint Energy Ltd., and Crescent Point Energy Ltd.

Dan Toews, Vice President, Finance & Chief Financial Officer

Dan Toews is a professional Accountant with over 21 years experience. Most recently, Mr. Toews was Vice President Finance and CFO at a private oil and gas company. Prior to that he was Vice President Finance and CFO at Peerless and co-founder of both Crescent Point Energy Trust and its predecessor Crescent Point Energy Ltd.

Bill Turko, Vice President, Engineering

Bill Turko is a professional Engineer with over 19 years experience in the oil and gas industry. Previously Mr. Turko was VP Engineering at Peerless and prior to that he was the Chief Operating Officer of Enterra Energy Trust, where he was responsible for operations of the trust and helped identity and evaluate potential acquisition opportunities. Prior to Enterra, Mr. Turko held a wide variety of engineering related roles at Impact Energy, ARC Energy Trust and Startech Energy.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Other than set out below, to our knowledge, no director or officer of the Company: (i) is, or has been in the last 10 years, a director, Chief Executive Officer or Chief Financial Officer of an issuer that, while that person was acting in that capacity, (a) was the subject of a cease trade order or similar order or an order that denied the issuer access to any exemptions under securities legislation, for a period of more than 30 consecutive days (an "**order**"), (b) was subject to an order that was issued after the director or officer ceased to be a director, Chief Executive Officer or Chief Financial Officer and which resulted from an event that occurred while that person was acting in the capacity as director, Chief Executive Officer or Chief Financial Officer, or (c) within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; (ii) has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangements or compromises with creditors, or had a receiver or receiver manager or trustee appointed to hold his assets; or (iii) has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority, or (b) any other penalties or sanctions imposed by a court or regulatory body.

John A. Brussa was a director of Imperial Metals Limited, a corporation engaged in oil and natural gas and mining operations, during the year prior to that corporation implementing a plan of arrangement under the *Companies Act* (British Columbia) and under the *Companies' Creditors' Arrangement Act* (Canada) which resulted in the separation of its two businesses. The reorganization resulted in the creation of two public corporations, Imperial Metals Corporation, engaged in the mining business, and IEI Energy Inc. (subsequently renamed Rider Resources Ltd.), engaged in the oil and gas business. The plan of arrangement was completed in April, 2002.

Conflicts of Interest

There are potential conflicts of interest to which the directors and officers of the Company will be subject in connection with the operations of the Company. In particular, certain of the directors and officers of the Company are involved in managerial and/or director positions with other oil and gas companies whose operations may, from time to time, be in direct competition with those of the Company or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of the Company. See "*Directors and Officers of the Company*". Conflicts, if any, will be subject to the procedures and remedies available under the ABCA. The ABCA provides that in the event that a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the ABCA.

DESCRIPTION OF SHARE CAPITAL

The following is a description of the rights, privileges, restrictions and conditions attaching to Pinecrest's share capital.

Common Shares

Pinecrest is authorized to issue an unlimited number of Common Shares without nominal or par value. Holders of Common Shares are entitled to one vote per share at meetings of shareholders. Subject to the rights of the holders of preferred shares ("**Preferred Shares**") and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors of Pinecrest and upon liquidation, dissolution or winding up to receive, Pinecrest's remaining property. There are currently 170,000,964 Common Shares issued and outstanding.

Preferred Shares

Pinecrest is authorized to issue an unlimited number of Preferred Shares without nominal or par value. There are currently no Preferred Shares issued and outstanding.

ESCROWED SECURITIES

The following securities of the Company are subject to contractual escrow restrictions pursuant to the terms of the Escrow Agreement. These securities were issued pursuant to the Capitalization Transaction. See "*General Development of the Business – Capitalization Transaction*".

Class of Securities	Number of Securities Escrowed	Percentage of Class
Common Shares	22,071,397[(1)]	27%
Purchase Warrants	22,071,397[(1)]	99%

Note:
(1) The following securities are scheduled to be released from escrow as follows:

Date	Number of Common Shares	Number of Purchase Warrants
May 6, 2011	6,822,210	6,822,210
May 21, 2011	534,923	534,923
November 6, 2011	6,822,210	6,822,210
November 21, 2011	534,923	534,923
May 6, 2012	6,822,209	6,822,209
May 21, 2012	534,922	534,922

PRICE RANGE AND TRADING VOLUME OF THE COMMON SHARES

On July 22, 2010, the outstanding Common Shares commenced trading on the TSXV under the trading symbol "PRY". Prior thereto, the Common Shares traded on the TSXV under the symbol “AFE”. The following table sets forth the price range and trading volume of the Common Shares as reported by the TSXV for the periods indicated.

Period	High	Low	Volume
2010			
January	0.45	0.45	18,000
February	0.61	0.275	50,300
March	0.69	0.5	49,100
April	1.35	0.74	444,345
May	1.65	1.30	1,118,162
June	1.43	1.06	492,252
July	1.45	1.10	2,255,522
August	1.58	1.25	4,810,048
September	1.37	1.33	8,230,063
October	1.85	1.36	17,236,555
November	1.90	1.55	15,289,491
December	1.79	2.97	26,620,496
2011			
January	2.12	2.80	13,544,406
February	2.57	2.21	8,263,612
March (1-22)	2.50	1.99	12,724,173

DIVIDENDS

The Company has not declared or paid any dividends since its incorporation. Any decision to pay dividends on its shares will be made by the board of directors on the basis of the Company's earnings, financial requirements and other conditions existing at such future time.

HUMAN RESOURCES

As at December 31, 2010, the Company had 13 full time employees and 2 other part time consultants. See "*Directors and Officers of the Company*".

PRIOR SALES

The following table sets forth the securities of the Company not listed or quoted on a recognized exchange or marketplace that have been issued in the most recently completed financial year, the issue price of the securities, the date of issue and the aggregate funds received.

Date of Issuance	Number and Type of Securities	Issue Price per Security	Aggregate Funds Received
October 8, 2010	4,900,000 options	$1.52	N/A
November 30, 2010	75,000 options	$1.85	N/A

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

To the knowledge of the Company, there are no legal proceedings material to the Company to which the Company is a party, or was a party to in 2010, or that any of its properties is or was the subject matter of in 2010, nor are there any such proceedings known to the Company to be contemplated.

During the year ended December 31, 2010 there were: (i) no penalties or sanctions imposed against the Company or by a court relating to securities legislation or by a securities regulatory authority; (ii) no other penalties or sanctions imposed by a court or regulatory body against the Company that would likely be considered important to a reasonable investor in making an investment decision; and (iii) no settlement agreements the Company entered into with a court relating to a securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than the interests described under the heading "*General Development of the Business – Year Ended December 31, 2010 – Capitalization Transaction"*, there were no material interests, direct or indirect, of directors or officers of the Company, of any shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of the outstanding Common Shares, or any other Informed Person (as defined in National Instrument 51-102) or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial that has materially affected or would materially affect the Company.

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of the Company's Audit Committee charter is included in Schedule C of this Annual Information Form.

Composition of the Audit Committee

The members of the Audit Committee are Robert Zakresky (Chairman), David Fitzpatrick and David Johnson each of whom are independent and financially literate. Pinecrest has adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*.

Relevant Education and Experience

Please refer to the individual biographies for the members of the audit committee above under the heading "*Directors and Officers of the Corporation*".

Pre-Approval of Policies and Procedures

The Audit Committee must pre-approve all non-audit services to be provided to the Company by its external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by the Audit Committee from time to time.

External Auditor Service Fees

Audit Fees

Buchanan Barry LLP was the Company's external auditors for the year ended July 31, 2010. For the year ended July 31, 2010, the aggregate fees were $16,500.

On November 8, 2010, PricewaterhouseCoopers LLP were appointed the Company's external auditors. The aggregate fees billed to date for the year ended December 31, 2010 was $14,000.

On November 25, 2010, Pinecrest changed its year end from July 31 to December 31, see *General Development of the Business – Year ended December 31, 2010 – Change of Year End*.

Audit-Related Fees

The aggregate fees billed in each of the last two fiscal years for assurance and related services by the external auditor that are reasonably related to the performance of the audit or review of the financial statements of the Company that are not reported under "*Audit Fees*" above were $20,000 paid to Buchanan Barry LLP for the year ended July 31, 2010 and $12,600 paid to PricewaterhouseCoopers LLP for the year ended December 31, 2010. Buchanan Barry LLP was paid $15,000 and PricewaterhouseCoopers LLP was paid $14,875 for IFRS conversion related services. Fees billed for prospectus review were $35,000 to Buchanan Barry LLP for the year ended July 31, 2010 and $16,800 to PricewaterhouseCoopers for the year ended December 31, 2010.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Company's external auditor for tax compliance, tax advice, tax planning and review of tax returns were $7,700 for the year ended July 31, 2010 and $nil for the year ended December 31, 2010. These fees were paid to Buchanan Barry LLP.

All Other Fees

There were no other auditor fees other than those reported above.

Reliance on Exemptions

Other than reliance of section 6.1 of National Instrument 52-110 – *Audit* Committees as a venture issuer, at no time since the commencement of our most recently completed financial year has the Company relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of its Audit Committee.

Audit Committee Oversight

At no time since the commencement most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Company's Board of Directors.

MATERIAL CONTRACTS

The Company has not entered into any material contracts within the most recently completed financial year, or before the most recently completed financial year which are still in effect.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining, transportation, and marketing) as a result of legislation enacted by various levels of government and with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these regulations or controls will affect the Company's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (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 issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements, and market considerations.

Pipeline Capacity

As a result of pipeline expansions over the past several years, there is ample pipeline capacity to accommodate current production levels of oil and natural gas in western Canada and pipeline capacity does not generally limit the ability to produce and market such production.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings.

NAFTA prohibits discriminatory border restrictions and export taxes. NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced when commodity prices are low to encourage exploration and development activity by improving earnings and cash flow within the industry.

Alberta

Producers of oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors, which changes included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month. Royalty curves incorporating the changes announced on March 11, 2010 were released on May 27, 2010.

With respect to conventional oil, the NRF eliminated the classification system used by the previous royalty structure which classified oil based on the date of discovery of the pool. Under the NRF, royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Royalty rates for conventional oil under the NRF ranged from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps were set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $\$535/m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF ranged from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps were set at $16.59/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF was reduced to 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the NRF. Prior to payout, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1-9% depending on the market price of oil: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increase for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1-9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of oil increase above $55 up to 40% when oil is priced at $120 or higher. An oil sands project reaches payout when its cumulative revenue exceeds its cumulative costs. Costs include specified allowed capital and operating costs related to the project plus a specified return allowance. As part of the implementation of the NRF, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the NRF.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

In April 2005, the Government of Alberta implemented the Innovative Energy Technologies Program (the "**IETP**"), which has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spud subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this new program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers were only able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that had already elected to adopt such rates as of that date were permitted to switch to Alberta's conventional royalty structure up until February 15, 2011. On January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. The program introduced a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program, both applying to conventional oil or natural gas wells drilled between April 1, 2009 and March 31, 2010. The drilling royalty credit provides up to a $200 per metre royalty credit for new wells and is primarily expected to benefit smaller producers since the maximum credit available will be determined using the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010, favouring smaller producers with lower activity levels. The new well incentive program initially applied to wells that began producing conventional oil or natural gas between April 1, 2009 and March 31, 2010 and provided for a maximum 5% royalty rate for the first 12 months of production on a maximum of 50,000 barrels of oil or 500 MMcf of natural gas. In June, 2009, the Government of Alberta announced the extension of these two incentive programs for one year to March 31, 2011. On March 11, 2010, the Government of Alberta announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations.

In addition to the foregoing, on May 27, 2010, in conjunction with the release of the new royalty curves, the Government of Alberta announced a number of new initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010;

Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

In addition to the foregoing, Alberta currently maintains a royalty reduction program for low productivity oil and oil sands wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil. Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a royalty in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* which replaces the existing *Freehold Oil and Gas Production Tax Act* and is intended to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new Act.

As with conventional oil production, base prices are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $50 per thousand m^3 for third and fourth tier gas and $35 per thousand m^3 for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.**

The Government of Saskatchewan currently provides a number of targeted incentive programs. These include both royalty reduction and incentive volume programs, including the following:

Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations);

Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002 providing reduced Crown royalty and freehold tax rates on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres or within certain formations);

Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002 treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing prior to April 1, 2005 providing Crown royalty and freehold tax determinations based in part on the profitability of enhanced recovery projects pre- and post-payout; and

Royalty/Tax Regime for Enhanced Oil Recovery Projects (Excluding Waterflood Projects) Commencing on or after April 1, 2005 providing a Crown royalty of 1% of gross revenues on enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences, and permits for varying terms, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

In Alberta, the NRF includes a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. The order in which these agreements will receive the reversion notice will depend on their vintage and location, with the older leases and licenses receiving reversion notices first beginning in January 2011. Leases and licences that were granted prior to January 1, 2009 but continued after that date will not be subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region.

While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 and commits Canada to reduce its GHG emissions levels to 6% below 1990 "business-as-usual" levels by 2012.

On February 14, 2007, the House of Commons passed Bill C-288, *An Act to ensure Canada meets its global climate change obligations under the Kyoto Protocol*. The resulting *Kyoto Protocol Implementation Act* came into force on June 22, 2007. Its stated purpose is to "ensure that Canada takes effective and timely action to meet its obligations under the Kyoto Protocol and help address the problem of global climate change." It requires the federal Minister of the Environment to, among other things, produce an annual climate change plan detailing the measures to be taken to ensure Canada meets its obligations under the Kyoto Protocol. It also authorizes the establishment of regulations respecting matters such as emissions limits, monitoring, trading and enforcement.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

Under the Updated Action Plan, regulated entities will also be able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations.

Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

The United Nations Framework Convention on Climate Change is working towards establishing a successor to the Kyoto Protocol. From December 7 to 18, 2009, a meeting between government leaders and representatives from approximately 170 countries in Copenhagen, Denmark (the "**Copenhagen Conference**") resulted in the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. From November 29 to December 10, 2010, a meeting between representatives from approximately 190 countries in Cancun, Mexico resulted in the Cancun Agreements, in which developed countries committed to additional measures to help developing countries deal with climate change. Unlike the Kyoto Protocol, however, neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets.

In response to the Copenhagen Accord, the Government of Canada indicated on January 29, 2010 that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which were discussed above.

Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

On December 23, 2010, the United States Environmental Protection Agency indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by July, 2011 and for refineries by December, 2011.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. Unlike the Updated Action Plan, the CCEMA does not contemplate a linkage to external compliance mechanisms such as the Kyoto Protocol's Clean Development Mechanism.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions. The Company does not own or have a working interest in facilities that meet or exceed the emissions threshold.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Company's other public filings before making an investment decision.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Company.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Company may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Company. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although the Company maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Company could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Global Financial Crisis

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and continued in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. Although economic conditions improved towards the latter portion of 2009 and in 2010, as anticipated, the recovery from the recession has been slow in various jurisdictions including in Europe and the United States and has been impacted by various ongoing factors including sovereign debt levels and high levels of unemployment which continue to impact commodity prices and to result in high volatility in the stock market.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by numerous factors beyond its control. The Company's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Company may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Company's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Company's reserves. The Company might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Company's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Company's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Company may, in part, be determined by the Company's borrowing base. A sustained material decline in prices from historical average prices could reduce the Company's borrowing base, therefore reducing the bank credit available to the Company which could require that a portion, or all, of the Company's bank debt be repaid.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Company makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Operational Dependence

Other companies operate some of the assets in which the Company has an interest. As a result, the Company has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Company's financial performance. The Company's return on assets operated by others therefore depends upon a number of factors that may be outside of the Company's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Company manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Company's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;

- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Company could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Company competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Company's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Company. The Company's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Company's costs, any of which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Company will require licenses from various governmental authorities. There can be no assurance that the Company will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The 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 of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. 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 governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it will be in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Climate Change

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. The Company's exploration and production facilities and other operations and activities emit greenhouse gases and require the Company to comply with greenhouse gas emissions legislation in Alberta and British Columbia or that may be enacted in other provinces. The Company may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which is now expected to be modified to ensure consistency with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits required by the Kyoto Protocol, the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Company. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Company and its operations and financial condition. See "Industry Conditions – Climate Change Regulation".

Variations in Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Company's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Company's reserves as determined by independent evaluators.

To the extent that the Company engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Company may contract.

An increase in interest rates could result in a significant increase in the amount the Company pays to service debt, which could negatively impact the market price of the Common Shares of the Company.

Substantial Capital Requirements

The Company anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Company's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Company to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Company. The inability of the Company to access sufficient capital for its operations could have a material adverse effect on the Company's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Company's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Company may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Company to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Company's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Company's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Company's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Company. Continued uncertainty in domestic and international credit markets could materially affect the Company's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Company's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Company may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Company's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Company may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Company's articles nor its by-laws limit the amount of indebtedness that the Company may incur. The level of the Company's indebtedness from time to time, could impair the Company's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Company will not benefit from such increases and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Company may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Company will not benefit from the fluctuating exchange rate.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Company and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Company's claim which may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Company's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Company's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Company's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Company intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and has not been updated and thus does not reflect changes in the Company's reserves since that date.

Insurance

The Company's involvement in the exploration for and development of oil and natural gas properties may result in the Company becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Company maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Company may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Company. The occurrence of a significant event that the Company is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Company is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle-East and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Company's net production revenue.

In addition, the Company's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Company's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company will not have insurance to protect against the risk from terrorism.

Dilution

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive.

Management of Growth

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Company to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Company to deal with this growth may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Company's properties are held in the form of licences and leases and working interests in licences and leases. If the Company or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Company's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Dividends

The Company has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Company, the need for funds to finance ongoing operations and other considerations as the board of directors of the Company considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. The Company is not aware that any claims have been made in respect of its properties and assets; however, if a claim arose and was successful such claim may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Company.

Third Party Credit Risk

The Company may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Company are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. See "*Directors and Officers of the Company – Conflicts of Interest*".

Reliance on Key Personnel

The Company's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. The Company does not have any key person insurance in effect for the Company. The contributions of the existing management team to the immediate and near term operations of the Company are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Company.

AUDITORS, REGISTRAR AND TRANSFER AGENT

The auditors of the Company are PricewaterhouseCoopers LLP, Chartered Accountants, Suite 3100, 111 – 5^{th} Avenue SW, Calgary, Alberta, T2P 5L3.

Olympia Trust Company, at its principal offices in Calgary, Alberta, is the registrar and transfer agent for the Common Shares.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Company during, or related to, the Company's most recently completed financial year other than Sproule, the independent reserve evaluator, and PricewaterhouseCoopers LLP, the Company's auditors. None of the principals of Sproule had any registered or beneficial interests, direct or indirect, in any securities or other property of the Company or of the Company's associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them. PricewatershouseCoopers LLP is independent in accordance with the auditors' rules of professional conduct in Canada.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Company or of any associate or affiliate of the Company.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at www.sedar.com. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of Common Shares and securities authorized for issuance under equity compensation plans, is contained in the Company's information circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided for in our financial statements and management's discussion and analysis for the year ended December 31, 2010.

SCHEDULE "A"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Pinecrest Energy Inc. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with the report.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

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

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

The Reserves Committee of the board of directors has reviewed the Company'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, on the recommendation of the Reserves Committee, has approved:

(d) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(e) the filing of Form 51-102F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(f) 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.

DATED as of this 23rd day of March, 2011.

(signed) "*Wade Becker*"
Wade Becker
President and Chief Executive Officer

(signed) "*Bill Turko*"
Bill Turko
Vice-President, Engineering

(signed) "*John Brussa*"
John Brussa
Director

(signed) "*David Johnson*"
David Johnson
Director

Form 51-101F2

Report on Reserves Data
by Independent Qualified Reserves Evaluator or Auditor

Report on Reserves Data

To the Board of Directors of Pinecrest Energy Inc. (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 attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us as of December 31, 2010, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country)	Net Present Value of Future Net Revenue Before Income Taxes (10% Discount Rate)			
			Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Pinecrest Energy Inc., As of December 31, 2010, prepared February to March 2011	Canada				
Total			**Nil**	**55,947**	**Nil**	**55,947**

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are presented in accordance with the consistent application of the COGE Handbook.

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

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
March __11__, 2011

Thomas K. Schenk, P.Eng.
Petroleum Engineer

Alec Kovaltchouk, P.Geol.
Manager, Geoscience and Associate

Robert N. Johnson, P.Eng.
Vice-President, Engineering
and Director

SCHEDULE "C"

PINECREST ENERGY INC.

AUDIT COMMITTEE CHARTER
AND POSITION DESCRIPTION FOR AUDIT COMMITTEE CHAIR

Introduction

Pinecrest Energy Inc. (the "Corporation") is an Alberta based junior oil and gas exploration and development company. The Board of Directors of the Corporation (the "Board") has the responsibility for the overall stewardship of the conduct of the business of the Corporation and its subsidiaries and the activities of management of the Corporation, which is responsible for the day-to-day conduct of the business.

Purpose

The primary function of the Audit Committee (the "Committee") is to assist the Board in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by the Corporation to any governmental body or the public; the Corporation's systems of internal controls regarding finance, accounting, legal compliance and ethics that management and the Board have established; and the Corporation's auditing, accounting and financial reporting processes generally. Consistent with this function, the Committee should endeavour to encourage continuous improvement of, and should endeavour to foster adherence to, the Corporation's policies, procedures and practices at all levels. In performing its duties, the external auditor is to report directly to the Committee. The Committee's primary objectives are:

(1) To assist directors meet their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

(2) To provide better communication between directors and external auditors;

(3) To assist the Board's oversight of the auditor's qualifications and independence;

(4) To assist the Board's oversight of the credibility, integrity and objectivity of financial reports;

(5) To strengthen the role of the outside directors by facilitating discussions between directors on the Committee, management and external auditors;

(6) To assist the Board's oversight of the performance of Corporation's internal audit function and external auditors; and

(7) To assist the Board's oversight of the Corporation's compliance with legal and regulatory requirements.

Composition, Procedures And Organization

(1) The Committee shall consist of at least three members of the Board of Directors (the "Board"), a majority of whom shall be "independent", as that term is defined in Sections 1.4 and 1.5 of Multilateral Instrument 52-110, *Audit Committees* ("MI 52-110") (provided that, if the Common Shares of the Corporation are listed and posted on the Toronto Stock Exchange, then all of the members of the Audit Committee shall be "independent").

(2) All of the members of the Committee shall be "financially literate" (i.e. able to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of those of the Corporation and that can be reasonably expected to be raised by the Corporation's financial statements).

(3) The Committee composition, including the qualifications of its members, shall comply with the applicable requirements of stock exchanges on which the Corporation lists its securities and of securities regulatory authorities, as such requirements may be amended from time to time.

(4) The Board shall appoint the members of the Committee. The Board may at any time remove or replace any member of the Committee and may fill any vacancy in the Committee.

(5) Unless the Board shall have appointed a chair of the Committee, the members of the Committee shall elect a chair from among their members.

(6) The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or other telecommunication device that permits all persons participating in the meeting to speak and to hear each other.

(7) The Committee shall have access to such officers and employees of the Corporation and to the Corporation's external auditors, and to such information respecting the Corporation, as it considers necessary or advisable in order to perform its duties and responsibilities.

(8) Meetings of the Committee shall be conducted as follows:

   (a) the Committee shall meet at least four times annually at such times and at such locations as may be requested by the chair of the Committee. The external auditors or any member of the Committee may request a meeting of the Committee;

   (b) the external auditors may receive notice of and have the opportunity to attend meetings of the Committee; and

   (c) the following management representatives may be invited to attend meetings, except executive sessions and private sessions with the external auditors:

President and Chief Executive Officer
Chief Financial Officer
Controller

other management representatives may be invited to attend as necessary.

(9) The external auditors shall report directly to the Committee and the external auditors and internal auditors (if any) shall have a direct line of communication to the Committee through its chair and may bypass management if deemed necessary. The Committee, through its chair, may contact directly any employee of the Corporation as it deems necessary, and any employee may bring before the Committee any matter involving questionable, illegal or improper financial practices or transactions.

(10) The Committee may retain, at the Corporation's expense, special legal, accounting or other consultants or experts it deems necessary in the performance of its duties and may set and pay the compensation for any advisor engaged. The Committee will notify the Board Chair whenever independent consultants are engaged.

Handling of Complaints

The Committee shall maintain procedures for the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters (a "Whistleblower Policy").

Annual Review

The Committee shall review and assess the adequacy of this Charter annually, report to the Board thereon and recommend any proposed changes to the Board for approval. The Committee shall also perform an annual evaluation of the performance of the Committee and shall report the results of the evaluation to the Board Chair.

Roles And Responsibilities

(1) The overall duties and responsibilities of the Committee shall be as follows:

(a) to assist the Board in the discharge of its responsibilities relating to the Corporation's accounting principles, reporting practices and internal controls and its approval of the Corporation's annual and quarterly financial statements and management's discussion and analysis;

(b) to establish and maintain a direct line of communication with the Corporation's internal (if any) and external auditors and assess their performance;

(c) to assist the Board in the discharge of its responsibilities relating to oversight of the Company's internal, financial and disclosure controls and procedures;

(d) to pre-approve all non-audit services to be provided by the Corporation's external auditor and to periodically review the audit and non-audit services pre-approval policy and recommend to the Board any changes which the Committee deems appropriate. The Committee may delegate to one or more members of the Committee authority to pre-approve non audit services in satisfaction of this requirement and if such delegation occurs, the pre-approval of non-audit services by the Committee member to whom authority has been delegated must be presented to the Committee at its first scheduled meeting following such pre-approval. The Committee shall be entitled to adopt specific policies and procedures for the engagement of non-audit services if:

(i) the pre-approval policies and procedures are detailed as to the particular service;

(ii) the Committee is informed of each non-audit service; and

(iii) the procedures do not include delegation of the Committee's responsibilities to management.

The Committee will satisfy the pre-approval requirement set forth above if:

(i) the aggregate amount of all non-audit services that were not pre-approved is reasonably expected to constitute no more than 5% of the total amount of fees paid by the Corporation and its subsidiary entities to the external auditors during the fiscal year in which the services are provided;

(ii) the Corporation or the subsidiary entity, as the case may be, did not recognize the services as non-audit services at the time of the engagement;

(iii) the services are promptly brought to the attention of the Committee and approved, prior to completion of the audit, by the Committee or by one or more of its members to whom authority to grant such approvals has been delegated by the Committee;

(e) to periodically consider whether there is a need to outsource internal audit functions or create an internal audit department;

(f) to review the reports to management prepared by the external auditors and management’s responses;

(g) to receive and review complaints received pursuant to the Corporation's Whistleblower Policy and oversee and provide direction on the investigation and resolution of such concerns and to periodically review the said policy and recommend to the Board changes which the Committee may deem appropriate;

(h) to report regularly to the Board on the fulfilment of its duties and responsibilities;

(i) to review significant findings during the year, including the status of previous significant audit recommendations;

(j) to identify and monitor the management of the principal risks that could impact the financial reporting of the Corporation;

(k) to ensure that it satisfies those responsibilities set out in Part 2 of MI 52-110 and provisions contained within the Companion Policy to MI 52-110; and

(l) review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors of the Corporation.

(2) The duties and responsibilities of the Committee as they relate to the external auditors shall be as follows:

(a) to be directly responsible for overseeing the work of the external auditors engaged for the purpose of preparing or issuing an auditor's report or performing other audit, review or attest services for the Corporation, including the resolution of disagreements between management and the external auditors regarding financial reporting;

(b) to recommend to the Board a firm of external auditors to be nominated for appointment by the shareholders of the Corporation, and to monitor and verify the independence of such external auditors;

(c) to review and approve the fee, scope and timing of the audit and other audit related and non-audit services rendered by the external auditors;

(d) review the audit plan of the external auditors prior to the commencement of the audit;

(e) to review with the external auditors, upon completion of their audit:

(i) contents of their report;

(ii) scope and quality of the audit work performed;

(iii) adequacy of the Corporation's financial and auditing personnel;

(iv) co-operation received from the Corporation's personnel during the audit;

(v) internal resources used;

(vi) significant transactions outside of the normal business of the Corporation;

(vii) significant proposed adjustments and recommendations for improving internal accounting controls, accounting principles or management systems; and

(viii) the non-audit services provided by the external auditors, as pre-approved pursuant to the audit and non-audit services pre-approval policy;

(f) to discuss with the external auditors the quality and not just the acceptability of the Corporation's accounting principles;

(g) when there is to be a change in external auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

(h) to review any unresolved issues between management and the external auditors that could affect the financial reporting or internal controls of the Corporation;

(i) to implement structures and procedures to ensure that the Committee meets the external auditors on a regular basis in the absence of management; and

(j) to receive a written statement from the external auditor describing in detail all relationships between the auditor and the Corporation that may impact the objectivity and independence of the auditor. The Committee shall review with the Board of Directors the independence of the external auditors and either confirms to the Board of Directors that the external auditors are independent or recommend that the Board of Directors take appropriate action to satisfy itself of the external auditor's independence.

(3) The duties and responsibilities of the Committee as they relate to the internal control procedures of the Corporation are to:

(a) review the appropriateness and effectiveness of the Corporation's policies and business practices which impact on the financial integrity of the Corporation, including those relating to insurance, accounting, information services and systems and financial controls, management reporting and risk management;

(b) review compliance under the Corporation's Code of Business Conduct with those matters addressed in the policy which affect the financial integrity of the Corporation and to periodically review this policy, management's monitoring of it, and recommend to the Board changes which the Committee may deem appropriate; and

(c) periodically review the Corporation's financial and auditing procedures and the extent to which recommendations made by the internal accounting staff or by the external auditors have been implemented.

(4) The Committee is also charged with the responsibility to:

(a) review and recommend to the Board for its approval, the Corporation's financial statements, management's discussion and analysis and annual and interim earnings press releases before the Corporation publicly discloses this information;

(b) review and approve the Corporation's interim financial statements, interim management's discussion and analysis including the impact of unusual items and changes in accounting principles and estimates and report to the Board with respect thereto and interim earnings press releases before the Corporation publicly discloses this information;

(c) review the financial sections of:

(i) the annual report to shareholders;

(ii) prospectuses;

(iii) other public reports containing financial information requiring approval by the Board; and

(iv) press releases related thereto,

and report to the Board with respect thereto;

(d) review regulatory filings and decisions as they relate to the Corporation's financial statements;

(e) review the appropriateness of any policies and procedures used in the preparation of the Corporation's financial statements and other required disclosure documents, and consider recommendations for any material change to such policies;

(f) review and report on the integrity of the Corporation's financial statements;

(g) review the minutes of any audit committee meeting of any subsidiary of the Corporation;

(h) review with management, the external auditors and, if necessary, with legal counsel, any litigation, 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 such matters have been disclosed in the consolidated financial statements;

(i) review the Corporation's compliance with regulatory and statutory requirements as they relate to financial statements, tax matters and disclosure of material facts;

(j) endeavour to ensure all material public documents relating to the financial performance, financial position or analysis thereon are reviewed by the Committee or another appropriate committee, as designated by the Board of Directors. In certain cases, including in respect of "roadshow" or other investor materials, the Committee may designate the responsibility for review to the Chair of the Committee, the Chief Financial Officer of the Corporation or to legal counsel. The Committee shall review and monitor practices and procedures adopted by the Corporation to assure compliance with applicable listing requirements, laws, regulations and other rules, and where appropriate, make recommendations or reports thereon to the Board of Directors;

(k) The Committee shall review significant changes in the accounting principles to be observed in the preparation of the accounts of the Corporation and its subsidiaries, or in their application, and in financial disclosure presentation; and

(l) The Committee shall review such reports as may be required by any applicable securities regulatory authority to be included in the Corporation's Information Circular or any other disclosure document of the Corporation.

Accountability

The Committee shall report its activities and proceedings to the Board by distributing the minutes of its meetings or by oral or written report at the next Board meeting.

Standards of Liability

Nothing contained in this mandate is intended to expand applicable standards of liability under statutory, regulatory, common law or any other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this mandate are meant to serve as guidelines rather than inflexible rules and the Committee may adopt such additional procedures and standards as it deems necessary from time to time to fulfill its responsibilities.

Annual Review And Assessment

The Committee shall conduct an annual review and assessment of its performance, including compliance with this Charter and its role, duties and responsibilities, and submit such report to the Board of Directors. The Committee shall also update this Charter periodically as conditions dictate.