PETROBANK

STRENGTH IN OUR RESOURCES

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2010

March 31, 2011

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ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

bbl/d	Barrels of oil per day	**M$**	Thousands of Canadian dollars
boe	Barrels of oil equivalent	**Mbbl**	Thousand barrels
boepd	Barrels of oil equivalent per day	**Mcf**	Thousand cubic feet of natural gas
bopd	Barrels of oil per day	**Mcf/d**	Thousand cubic feet of natural gas per day
km	kilometre	**MMbbl**	Million barrels
km^2	Square kilometres	**MMcf**	Million cubic feet of natural gas
m	metre	**MMcf/d**	Million cubic feet of natural gas per day
m^3	Cubic metre	**NGL**	Natural gas liquids
10^3m^3	Thousands of cubic metres	**US$**	United States dollars

In this Annual Information Form, the capitalized terms set forth below have the following meanings:

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, together with all regulations promulgated thereunder;

"**AENV**" means Alberta Environment;

"**API**" means as a degree of gravity that provides a relative measure of crude oil density;

"**Archon**" means Archon Technologies Ltd., a wholly-owned subsidiary of Petrobank, incorporated under the laws of the Province of Alberta;

"**Baytex**" means Baytex Energy Trust;

"**Berens**" means Berens Energy Inc., a corporation acquired by PetroBakken on February 25, 2010;

"**Board**" means the Board of Directors of Petrobank;

"**Canadian Business Unit**" or "**CBU**" means the operations, properties and assets of PetroBakken, in which the Company had a 59% interest as at December 31, 2010, as more particularly described under the heading "*PetroBakken Overview*";

"**CAPRI®**" means the Company's CAPRI® technology, which is an enhancement to the Company's THAI® technology offering the potential for further in-situ upgrading through the use of a well-bore integrated catalyst;

"**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 and Petroleum;

"**common shares**" means the issued and outstanding common shares in the capital of the Company;

"**Company**" means Petrobank Energy and Resources Ltd., and where applicable also refers to its subsidiaries;

"**Conklin Pilot**" means Petrobank's first THAI® pilot project near Conklin, Alberta;

"**CSS**" means cyclic steam stimulation;

"**Dawson Property**" means Petrobank's 100% interest in 20,160 acres of heavy oil lands and related assets in the Peace River region of northwest Alberta;

"**ERCB**" means Energy Resources and Conservation Board;

"**Former Petrobank Assets**" means Petrobank's and all of its subsidiaries' Canadian conventional petroleum and natural gas assets and all tangibles, intangibles and facilities related thereto, which were conveyed to PetroBakken prior to the PetroBakken Arrangement, including all of the assets and liabilities owned by or being held for the benefit of Petrobank Production Partnership and Petrobank Oil and Gas Ventures, LP and defined in Petrobank's public filings as its "Canadian Business Unit";

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

"**Glover Property**" means, collectively, the oil sands leases held by Whitesands in respect of 10.25 sections (6,560 net acres) of land located in Township 75, Range 9, within the Province of Alberta, approximately 6.5 kilometres south of the May River Property;

"**Gross**" means: (a) in relation to the Company's interest in production and reserves, its "Company gross 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;

"**Heavy Oil Business Unit**" or "**HBU**" means all of the operations, properties and assets of Petrobank, other than its interest in PetroBakken, which are held through Whitesands and are more particularly described under the heading "*Heavy Oil Business Unit Overview*";

"**Kerrobert Property**" means Petrobank's 100 percent interest in three sections of land in the Kerrobert Mannville heavy oil pool in Saskatchewan;

"**Kerrobert Project**" means the Company's two THAI® well-pair pilot project and ten well-pair expansion project on the Kerrobert Property;

"**Latin American Business Unit**" or "**LABU**" means the operations, properties and assets of Petrominerales, of which Petrobank had a 65% interest that it distributed to its shareholders effective December 31, 2010 pursuant to the Petrominerales Reorganization;

"**May River Property**" means, collectively, the oil sands and heavy oil leases held by Whitesands in respect of 62 sections (39,680 net acres) of land located in Townships 76-78, Ranges 8-10W4, within the Province of Alberta and includes the Conklin Pilot;

"**McDaniel**" means McDaniel and Associates Consultants Ltd., independent petroleum engineers, of Calgary, Alberta, Canada;

"**McDaniel Report**" means the evaluation of the Heavy Oil Business Unit's heavy oil and bitumen reserves and contingent resources (excluding the Glover Property, the Dawson Property and the Sutton Creek Property) based on forecast prices and costs dated March 9, 2011, with an effective date of December 31, 2010;

"**Net**" means: (a) in relation to the Company's interest in production and reserves, its working interest (operating and non-operating) share of reserves or production after deduction of royalty obligations, plus

the Company's royalty interest in production or reserves; (b) in relation to wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and (c) 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;

"**NI 51-101**" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities of the Canadian Securities Administrators;

"**Peerless**" means Peerless Energy Inc., a company acquired by Petrobank on January 28, 2008;

"**PetroBakken**" means PetroBakken Energy Ltd., a subsidiary of Petrobank, in which Petrobank had a 59% interest as at December 31, 2010, and is also referred to herein as the Canadian Business Unit;

"**PetroBakken Arrangement**" the plan of arrangement between Petrobank, PetroBakken and TriStar effective October 1, 2009, whereby PetroBakken acquired TriStar, as more particularly described under the heading "*Corporate Structure*";

"**PetroBakken Notes**" means the 3.125% convertible notes of PetroBakken that mature January 2016;

"**PetroBakken Shares**" means Class A shares of PetroBakken;

"**Petrobank**" means Petrobank Energy and Resources Ltd.;

"**Petrominerales**" means Petrominerales Ltd., in which Petrobank had a 65% interest as at December 31, 2010 which was transferred directly to the Petrobank shareholders on December 31, 2010 pursuant to the Petrominerales Reorganization;

"**Petrominerales Reorganization**" means the series of transactions completed December 31, 2010 pursuant to which, among other things, Petrobank effectively distributed its 65% ownership of Petrominerales directly to its shareholders;

"**PIHC**" means pre-ignition heating cycle (See "*THAI® Process Steps*");

"**Preferred Shares**" means the preferred shares of the Company, issuable in series;

"**Result Energy**" means Result Energy Inc., a corporation acquired by PetroBakken on April 1, 2010;

"**Rocor**" means Rocor Resources Inc., a private company acquired by Petrobank on October 2, 2008;

"**Rondo**" means Rondo Petroleum Inc., a private company acquired by PetroBakken on March 12, 2010;

"**SAGD**" means steam assisted gravity drainage;

"**Sproule**" means Sproule Associates Limited, independent petroleum engineers, of Calgary, Alberta, Canada;

"**Sproule Report**" means the independent engineering evaluation of PetroBakken's crude oil and natural gas reserves prepared by Sproule, dated February 18, 2011, with an effective date of December 31, 2010;

"**subsidiary**" has the meaning given to such term in the *Securities Act* (Alberta);

"**Sutton Creek Property**" means, collectively, the oil sands licences held by Whitesands comprised of 23,040 acres of land located in the Province of Saskatchewan (Township 91, Ranges 24);

"**THAI®**" means Petrobank's patented Toe-to-Heel-Air-Injection in-situ heavy oil recovery technology, which combines a vertical air injection well with a horizontal production well, indirectly owned through Archon;

"**TPC**" means Technology Partnerships Canada;

"**TriStar**" means TriStar Oil & Gas Ltd., a corporation that was acquired by PetroBakken pursuant to the PetroBakken Arrangement;

"**TSX**" means the Toronto Stock Exchange;

"**WTI**" means West Texas Intermediate; and

"**Whitesands**" means Whitesands Insitu Partnership, a partnership between Petrobank and its wholly-owned subsidiary, Whitesands Insitu Inc.

NOTES

General

Boe disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. Six thousand cubic feet (Mcf) of natural gas is equal to one barrel (bbl) based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Certain other terms used in this Annual Information Form but not otherwise defined herein shall have the same meanings as defined in NI 51-101 unless the context otherwise requires.

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

Unless the context otherwise requires, reference in this Annual Information Form to "Petrobank" or the "Company" are to Petrobank Energy and Resources Ltd. and its subsidiaries including interests in joint ventures and partnerships.

Unless otherwise noted, the Company's average daily production volumes disclosed herein are based on the Company's working interest production before deduction of royalties paid to others and including royalty volumes received.

Non-GAAP Measures

This Annual Information Form contains financial terms that are not considered measures under Canadian generally accepted accounting principles ("**GAAP**"), such as operating netbacks. These measures are commonly utilized in the oil and gas industry and are considered informative for management and shareholders. Profitability relative to commodity prices per unit of production is demonstrated by an operating netback. Operating netback is determined by dividing oil and natural gas sales less royalties, transportation and operating expenses by sales volumes. Management considers operating netback important as it is a measure of profitability per unit of production and reflects the quality of production.

Operating netbacks may not be comparable to those reported by other companies nor should they be viewed as an alternative to other measures of financial performance calculated in accordance with GAAP.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements contained in this Annual Information Form constitute forward-looking statements. The Company believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct. Accordingly, any such forward-looking statements are qualified in their entirety by reference to, and are accompanied by, the factors discussed throughout this Annual Information Form. Such forward-looking statements included in this Annual Information Form should not be unduly relied upon.

In particular, this Annual Information Form may contain forward-looking statements pertaining to the following:

- the characteristics of the Company's oil, heavy oil, bitumen and natural gas properties;
- oil and natural gas production levels;
- the size of the oil and natural gas reserves and resources;
- projections of market prices and costs;
- supply and demand for oil and natural gas;
- expectations regarding the ability of the Company to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws;
- future capital expenditures;
- receipt of anticipated regulatory approvals;
- the performance characteristics of existing and potential projects and technologies;
- anticipated economic, operational and environmental benefits of the THAI® process;
- projected recovery factors and levels of in situ upgrading of bitumen and heavy oil resulting from the THAI® process; and
- the suitability of various reservoir types for application of the THAI® process.

With respect to forward looking statements contained in this Annual Information Form, the Company has made assumptions regarding:

- oil and natural gas production levels;
- commodity prices;
- general economic and financial market conditions;
- timing and amount of capital expenditures;
- operating costs;
- performance of new technologies with respect to the development of heavy oil and bitumen resources;
- availability of labour and drilling equipment;
- government regulation in the areas of taxation, royalty rates and environmental protection; and
- the receipt of necessary regulatory approvals.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form:

- volatility in market prices for oil and natural gas;
- fluctuation in foreign currency exchange rates;
- financial resources of the Company, including access to equity or debt markets;

- global economic conditions;
- risks inherent in oil and natural gas operations (including operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production, costs and expenses, reliance on industry partners, availability of equipment and personnel, and uncertainty surrounding timing for drilling and completion activities resulting from weather or access restrictions);
- uncertainties associated with estimating oil and natural gas reserves;
- uncertainties inherent in the Company's early stage projects and technologies due to a lack of operating history;
- competition for, among other things, capital, acquisitions of reserves and undeveloped lands;
- geological, technical, drilling and processing problems;
- the ability to economically test, develop and utilize the technologies described herein, including THAI® and CAPRI®;
- changes in legislation, including changes in environmental or tax laws, royalty regimes and government incentive programs relating to the oil and gas industry; and
- the other factors discussed under the heading "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement. Further, any forward-looking statement is made only as of a certain date, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events, except as may be required by applicable securities laws. New factors emerge from time to time, and it is not possible for management of the Company to predict all of these factors and to assess in advance the impact of each such factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

BUSINESS OF THE COMPANY

Petrobank Energy and Resources Ltd. is a Calgary-based oil and natural gas exploration, production and technology company with operations in western Canada. Prior to December 31, 2010, the Company also owned approximately 65% of Petrominerales, which is a Latin American based exploration and production company with operations in Colombia and Peru. On December 31, 2010, the Company completed the Petrominerales Reorganization, pursuant to which it effectively distributed its entire ownership of Petrominerales directly to its shareholders. As Petrobank no longer held an interest in Petrominerales as at December 31, 2010, this Annual Information Form does not include information in respect of the business or operations Petrominerales, except where indicated. Further information in respect of Petrominerales can be found in its Annual Information Form, which is accessible on the Petrominerales profile at www.sedar.com.

The Company operates high-impact projects through its Canadian Business Unit and Heavy Oil Business Unit, as well as its technology subsidiary, Archon.

The Canadian Business Unit, operated by Petrobank's 59% owned TSX-listed subsidiary, PetroBakken, targets significant production and reserves growth through by combining light oil Bakken and Cardium resource plays with conventional light oil assets, delivering industry leading operating netbacks, strong cash flows and production growth. PetroBakken is applying leading edge technology to a multi-year inventory of Bakken and Cardium light oil development locations, along with a significant inventory of opportunities in the Horn River and Montney gas resource plays in northeast BC. Our strategy is to deliver accretive production and reserves growth, along with an attractive dividend yield.

Whitesands Insitu Partnership, a partnership between Petrobank and its wholly-owned subsidiary Whitesands Insitu Inc., owns oil sands leases in Alberta, oil sands and heavy oil licenses and leases in Saskatchewan and operates the Conklin Pilot and Kerrobert Projects which are field-demonstrating Petrobank's patented THAI® oil sands and heavy oil in-situ recovery process. THAI® is an evolutionary in-situ combustion technology for the recovery of bitumen and heavy oil that integrates existing proven technologies and provides the opportunity to create a step change in the development of heavy oil resources globally. THAI® and CAPRI® are registered trademarks of Archon, a wholly-owned subsidiary of Petrobank.

CORPORATE STRUCTURE

The Company was incorporated under the ABCA on December 1, 1983 as "Petrobank Energy Resources Ltd." On September 8, 1986, Articles of Amendment were filed to change the Company's name to "Petrobank Energy and Resources Ltd." On September 8, 1993, the Company filed Articles of Amendment to delete the private company restrictions thereunder. The Company filed Articles of Amendment on March 7, 2000 to create the first series of Preferred Shares designated as Preferred Shares, Series A and on August 22, 2000 to create the second and third series of Preferred Shares designated as Preferred Shares, Series B and Series C (these preferred shares are no longer outstanding). On January 1, 2002, the Company filed Articles of Amalgamation to amalgamate with its wholly-owned subsidiary, Barrington Petroleum Ltd.

Effective December 31, 2007, Petrobank and its wholly-owned subsidiary Whitesands Insitu Inc. formed Whitesands Insitu Partnership. Effective January 1, 2008, Petrobank amalgamated with its wholly-owned subsidiaries Orion Oil Canada Ltd. and Whitesands Insitu Ltd. Effective January 28, 2008, Petrobank amalgamated with Peerless Energy Inc. Effective January 1, 2009, Petrobank amalgamated with Denison Resources Holding Corporation, Rocor Resources Inc. and 1424107 Alberta Ltd.

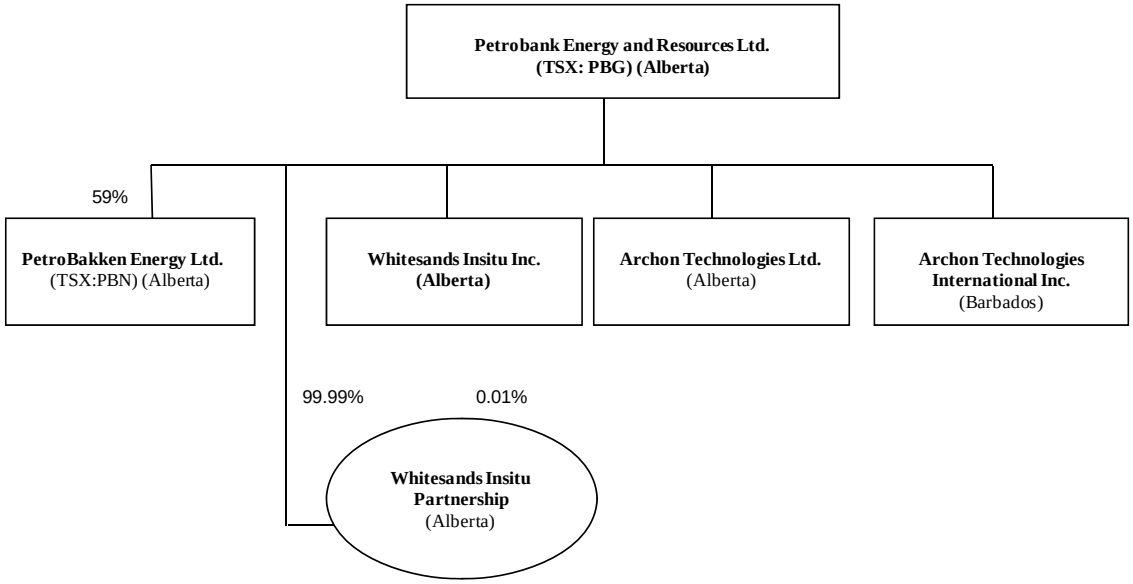
On July 30, 2009, PetroBakken was incorporated. On September 30, 2009, PetroBakken was capitalized by Petrobank with the Former Petrobank Assets and $400 million of cash. In return, Petrobank received 109.8 million shares of PetroBakken. On October 1, 2009, PetroBakken acquired all of the issued and outstanding shares of TriStar pursuant to the PetroBakken Arrangement.

On December 31, 2009, pursuant to an internal re-organization, PetroBakken completed three successive amalgamations with three wholly-owned subsidiaries of PetroBakken: PetroBakken Production Ltd., PetroBakken Resources Ltd. and PetroBakken Development Ltd. (formerly TriStar).

On December 31, 2010, pursuant to an internal re-organization, PetroBakken completed three successive amalgamations with three wholly-owned subsidiaries of PetroBakken: PetroBakken Exploration Ltd., PetroCardium Exploration Ltd. and PetroPembina Exploration Ltd.

The Company's principal office and head office is located at Suite 1900, 111 - 5th Avenue S.W., Calgary, Alberta, T2P 3Y6. The Company's registered office is located at 3300, 421 - 7th Avenue S.W., Calgary, Alberta, T2P 4K9.

As of the date of this Annual Information Form, the material subsidiaries of the Company, each of which is wholly-owned (except as noted), and their jurisdictions of incorporation or formation are as follows:



THREE-YEAR HISTORY OF THE BUSINESS

Year ended December 31, 2008

On January 3, 2008, Petrobank announced the release of Whitesands' Public Disclosure Document relating to the proposed May River Project. See "*Heavy Oil Business Unit Overview - May River Project*".

On January 28, 2008, Petrobank acquired Peerless for $338.8 million, including net debt assumed.

On September 22, 2008, the Company announced the world's first CAPRI® in-situ catalytic production well at our Conklin Pilot.

On October 2, 2008, the Company completed the acquisition of Rocor for total consideration of approximately $53 million, comprised of 699,183 Petrobank common shares and $26.5 million in cash.

On November 21, 2008, Petrobank entered into a royalty, technology license and a joint operating agreement with True Energy Trust (subsequently, in June 2009, Baytex Energy Trust acquired certain oil and gas assets, including the royalty, technology license and joint operating agreement, from True Energy Trust) to apply Petrobank's patented THAI® heavy oil recovery technology on certain heavy oil properties near Kerrobert, Saskatchewan (see "*Heavy Oil Business Unit Overview*").

On November 28, 2008, the Company announced that the ERCB approved a three well development at Petrobank's Conklin Pilot site.

On December 18, 2008, Petrobank announced that it had filed its application for the May River Project with the ERCB and AENV. The May River Project is Petrobank's proposed 10,000 bopd THAI® commercial demonstration project to be developed on our May River Property located two kilometres from the current Conklin Pilot project site.

Year Ended December 31, 2009

Petrobank

On May 15, 2009, Petrobank's wholly-owned subsidiary, Petro International Ltd., completed a public secondary offering of 9.9 million common shares of Petrominerales at a price of $10.25 per common share, resulting in gross proceeds of $101,475,000. Petrominerales did not receive any proceeds from the secondary offering, which reduced Petrobank's ownership of Petrominerales from 77% to 67%.

On June 16, 2009, Petrobank announced that holders of Petrobank's US$250,000,000 principal amount convertible debentures agreed to convert US$244,900,000 principal amount of notes to common shares of Petrobank in accordance with such debenture holders' existing conversion right and the conversion incentive period.

On July 10, 2009, Petrobank raised US$400 million through the private placement of 5.125% convertible debentures due 2015.

Formation of PetroBakken

On July 30, 2009, PetroBakken was incorporated and on August 4, 2009, Petrobank and PetroBakken entered into an arrangement agreement with TriStar whereby PetroBakken agreed to acquire all the issued and outstanding shares of TriStar pursuant to the PetroBakken Arrangement.

On September 30, 2009, Petrobank capitalized PetroBakken with the Former Petrobank Assets and $400 million in cash and in return received 109.8 million common shares of PetroBakken.

On October 1, 2009, Petrobank, PetroBakken and TriStar completed the PetroBakken Arrangement, pursuant to which PetroBakken acquired all of the issued and outstanding shares of TriStar, with TriStar shareholders receiving, in the aggregate, approximately $584.5 million in cash and 61.8 million PetroBakken Shares, which represented approximately 36% of PetroBakken's outstanding shares. PetroBakken commenced trading on the TSX on October 6, 2009 under the symbol 'PBN'.

Heavy Oil Business Unit

In the second half of 2009, Petrobank constructed two THAI® well pairs and initiated air injection at our Kerrobert Project. The entire construction and start-up cycle, from the time the regulatory application was filed until air injection was initiated, took less than six months.

PetroBakken

On December 21, 2009, PetroBakken closed an asset disposition consisting of approximately 2,000 boepd for net proceeds of $179 million in northwest Alberta.

Year Ended December 31, 2010

Heavy Oil Business Unit

On March 10, 2010, Petrobank announced that McDaniel had completed the first comprehensive evaluation of THAI® at our Conklin Pilot as the initial step for assigning reserves and resources, concluding that the Conklin Pilot was successfully proving the THAI® process.

On January 8, 2010, Petrobank completed an early conversion offering which resulted in US$250.7 million principal amount of 5.125% convertible debentures due July 10, 2015 being exercised prior to maturity. Upon the conversion, a total of 7,452,099 Petrobank common shares were issued. On April 23, 2010, the remaining US$149.3 million principal amount of Petrobank's 5.125% convertible debentures was early converted. An aggregate of US$27.4 million was paid and 3,920,446 common shares were issued. On May 10, 2010, the remaining US$5.1 million principal amount of Petrobank's 3% convertible debentures was early converted into 179,009 common shares. As a result of these three events, there are no longer any Petrobank convertible debentures outstanding.

On May 6, 2010, Petrobank, PetroBakken and Petrominerales announced certain executive appointments. Mr. Corey Ruttan resigned his position of Executive Vice President and Chief Financial Officer of Petrobank to assume the role of President and Chief Executive Officer of Petrominerales. Mr. Allen Knight resigned his role as Vice President, New Ventures of Petrobank to assume a full time role of Vice President, New Ventures of Petrominerales. On August 14, 2010, Mr. Peter Cheung was appointed the Vice President Finance and Chief Financial Officer of Petrobank.

On September, 30, 2010, Petrobank acquired Baytex's 50% working interest in the Kerrobert Phase-1 project lands and wells, consisting of the two-well pilot project and approximately 1,300 net acres of land, for cash consideration of approximately $18.1 million. Baytex retained a gross overriding royalty on its working interest in the Phase-1 lands, commencing 12 months after first production from the Kerrobert expansion project. Baytex also retained its 50% interest in the area of mutual interest surrounding the Phase-1 lands.

On October 8, 2010, Petrobank acquired Shell's 50% working interest and work commitments in the Dawson Property and a 100% working interest in an additional 27 sections (17,280 acres) of land prospective for Bluesky heavy oil resource adjacent to the Dawson project for aggregate cash proceeds of approximately $2.8 million, which was received upon obtaining regulatory approval for the project in January 2011.

On November 29, 2010, Petrobank announced that it had received the final AENV approval for the initial two well-pair THAI® Dawson project. ERCB approval for the project was received on October 28, 2010.

Based on McDaniel's evaluation at December 31, 2010, Petrobank recognized THAI® proved and proved plus probable reserves for the Kerrobert project of 3.0 million barrels and 4.8 million barrels, respectively, with before tax net present value discounted at 8% of $6.2 million and $46 million, respectively. This third party validation of the THAI® technology confirmed that THAI® is able to economically extract oil in a reservoir that had previously been conventionally produced. Additionally, McDaniel forecast that the THAI® sales oil price at Kerrobert will receive a 10% premium over conventional native quality heavy oil. See "*Statement of Reserves and Resources*".

PetroBakken

On February 25, 2010, PetroBakken indirectly acquired all of the issued and outstanding shares of Berens for cash consideration of $253 million plus the assumption by PetroBakken of Berens' indebtedness.

On January 25, 2010, PetroBakken issued US$750 million principal amount of Notes due 2016. The PetroBakken convertible notes are convertible into PetroBakken Shares, with an annual interest rate of 3.125% and an initial conversion price of US$39.61 per PetroBakken Share, as adjusted for dividends paid.

On March 12, 2010, PetroBakken acquired all the issued and outstanding shares of Rondo, a Cardium focused private company, for cash consideration of approximately $89 million, the issuance of approximately 5.5 million PetroBakken Shares and the assumption of Rondo's debt.

On April 1, 2010, PetroBakken acquired all of the issued and outstanding shares of Result Energy pursuant to a plan of arrangement for aggregate consideration of approximately $141 million net cash and 11.2 million PetroBakken Shares.

On May 18, 2010, PetroBakken commenced a normal course issuer bid (the "**NCIB**"). In accordance with the NCIB, PetroBakken was authorized to repurchase up to 9,431,255 PetroBakken Shares, representing approximately 5% of the issued and outstanding PetroBakken shares at such time. In 2010, PetroBakken repurchased a total of 1,680,400 PetroBakken Shares under the NCIB at an average price of $21.68.

Petrominerales Reorganization

On November 2, 2010, Petrobank and Petrominerales announced an agreement to implement the Petrominerales Reorganization. The purpose of the Petrominerales Reorganization was for Petrobank to distribute its 65% ownership of Petrominerales directly to the Petrobank shareholders. The distribution was accomplished through the incorporation of 1567725 Alberta Ltd. ("**New Petrominerales**") and the completion of a series of transactions pursuant to which:

- New Petrominerales acquired all of the shares of Petro International Ltd., thereby indirectly acquiring approximately 65% of the shares of Petrominerales Ltd. ("**Old Petrominerales**");

- Each of the common shares of Petrobank was exchanged for a new common share of Petrobank and 0.6142 of a share of New Petrominerales; and

- Each common share of Old Petrominerales, other than those held by Petro International, was exchanged for one common share of New Petrominerales.

The Petrominerales Reorganization was completed on December 31, 2010. Immediately thereafter, New Petrominerales changed its name to "Petrominerales Ltd." and Old Petrominerales changed its name to

Petrominerales Bermuda Ltd. Following the Petrominerales Reorganization, the common shares of New Petrominerales traded on the TSX under the symbol "PMG" in substitution for the Old Petrominerales common shares.

Recent Developments

Heavy Oil Business Unit

On January 4, 2011, Petrobank entered into a new three-year $200,000,000 credit agreement with a syndicate of lenders. The credit agreement is secured by a portion of Petrobank's PetroBakken common shares and a general security assignment on other corporate assets.

OVERVIEW OF THE BUSINESS AND DESCRIPTION OF PRINCIPAL PROPERTIES

PetroBakken Principal Properties

Key properties of PetroBakken, Petrobank's 59% owned subsidiary as at December 31, 2010, include the following:

Bakken Formation, Southeast Saskatchewan

The Bakken formation continued to be PetroBakken's primary operational focus in 2010. Since late 2009, PetroBakken has been utilizing bilateral drilling techniques to improve primary recoveries and capital efficiencies. PetroBakken drilled 177 gross (140 net) horizontal wells in 2010, of which 130 (121 net) wells were bilateral horizontal wells. The 2010 Bakken development drilling program started with 9 drilling rigs up until spring breakup. Wet weather in June forced 4 rigs to be racked until surface conditions improved. PetroBakken had 8 to 9 rigs operating by the third quarter and 10 rigs operating by the end of the year.

PetroBakken continued to further refine its drilling and completion expertise in 2010. PetroBakken continued to have success with bilateral horizontal wells in certain areas, increasing productivity and reserves beyond those achieved with single leg horizontal wells. Advances were also made in completion techniques in areas that are prone to break-out into water wet zones above the Bakken. In addition, PetroBakken experimented with single leg horizontal wells that were put on production without completion until a certain predetermined amount of oil was produced. This technique helped contain the hydraulic fracture within the pay zone by creating a pressure sink around the wellbore.

Land sale activity was down from previous years, with Petrobakken adding 5.7 net sections to its undeveloped land inventory for gross costs of $23.2 million.

In 2010 PetroBakken successfully field tested enhanced oil recovery ("EOR") in the Bakken using CO_2 as a proxy for natural gas. One well was shut-in in February 2010 for a two day CO_2 stimulation followed by a two month soaking period. By April 2010, response to the stimulation was evident in offsetting wells with large boosts in production. By March 2011 production continued to exceed pre-stimulation levels by 50% and cumulatively PetroBakken has recovered an incremental 11,000 bbl of light oil. PetroBakken will continue monitoring this CO_2 test and we will have up to five natural gas EOR projects commencing in 2011. The majority of the natural gas used for these EOR projects will come from PetroBakken's own production facilities and is expected to be recovered and sold at a later date, which further enhances the full cycle economics of EOR.

Conventional Southeast Saskatchewan and Southwest Manitoba

In Southeast Saskatchewan, PetroBakken continued to drill conventional Mississippian oil targets in 2010, primarily in the Fertile, Bellegarde, Acrola and Star Valley properties. PetroBakken started the year with 2 rigs and then dropped to 1 rig by May 2010. A Frobisher discovery was drilled in September at Creelman and a Tilston discovery was drilled in October at Bellegarde using existing 3D seismic data. In Saskatchewan, PetroBakken also added 3.5 net sections of land to its undeveloped land base, and has been able to maintain an inventory of 350 drilling locations.

In Manitoba, PetroBakken drilled three net horizontals wells into the Spearfish formation at Goodlands. All three encountered oil during the drilling but produced water upon completion due to breaking out of zone into an underlying wet formation. A new completion technique was designed and a fourth well, at 100% working interest, was drilled and successfully completed as an oil well and has been turned over to production. PetroBakken plans to continue drilling into the Spearfish using this new completion technique to preserve expiring lands. An exploratory well was also drilled at Goodlands into the Tilston but encountered only formation water and was abandoned. The Company added 1.6 net sections to its undeveloped land base in this area.

During 2010, PetroBakken drilled a total of 71 (42 net) wells in southeast Saskatchewan and southwest Manitoba.

Cardium, Alberta

PetroBakken entered the Cardium light oil play with the acquisitions of Berens and Rondo in the first quarter of 2010 and Result Energy in April 2010. PetroBakken continued to add to its existing land holdings in the Cardium through strategic property acquisitions and successful land sales, purchasing 58 sections of land for $84 million. At December 31, 2010, PetroBakken has access to over 320 gross (240 net) sections of land that are prospective for the Cardium light oil resource play, with over 650 net potential Cardium locations, and PetroBakken expects that this drilling inventory will increase with further evaluation of the Cardium lands. Similar to the Bakken light oil resource play, the Cardium resource play requires horizontal wells with multi-staged fracs to produce economically.

Following completion of the corporate acquisitions, PetroBakken began designing and operating the drilling and completing of wells and was able to leverage its expertise gained in the Bakken to drill long leg horizontals and complete them with 15 to 20 stage fracture stimulations. PetroBakken quickly determined that utilizing monobore drilling and slick water frac completions resulted in a significant cost savings and improved results.

PetroBakken began its operations with 2 rigs, which expanded to 5 rigs by August, 7 rigs by October and 10 rigs by year end. PetroBakken drilled 75 (55 net) Cardium horizontal wells in 2010 of which 40 (33 net) were drilled in the fourth quarter.

Monias, Northeastern British Columbia

PetroBakken holds 17 sections of 100% working interest lands, and at four wells per section PetroBakken has a total of 68 potential locations (three of which have now been drilled). In September 2009, PetroBakken used the drilling and completion expertise gained in the Bakken to drill its second well as a long (1,600 metre) bilateral, with both legs targeting the prolific upper portion of the 135 metre thick gas saturated Montney formation. The well was put on production from only one horizontal leg at a restricted rate of 6 MMcf/d due to through-put restrictions at PetroBakken's 8-22 gas facility. The second horizontal leg was fracture stimulated in February, 2010 and is presently being production tested. A third well was

drilled in November 2010 as a single leg horizontal to preserve expiring land and is scheduled to be completed along with a well being drilled in February 2011.

Horn River, Northeastern British Columbia

PetroBakken decreased its activity in the Horn River Basin to just one well on its Poplar Hills land in 2010 due to low commodity prices. The well was drilled to the Muskwa formation but encountered mechanical difficulties associated with natural faulting in the area. A shallower zone was identified as having potential and that zone was targeted in June 2010 with a 1,000m horizontal lateral from the same wellbore. The zone was completed in November 2010 with positive gas indications. It was then shut-in for pressure build up analysis in January 2011 and will be evaluated for further testing.

Heavy Oil Business Unit Overview

The Heavy Oil Business Unit is focused on developing heavy oil and oil sands resources utilizing our proprietary THAI®, CAPRI®, and other related proprietary technologies. We believe these technologies can be used in a wide range of conventional heavy oil and oil sands reservoirs worldwide. At our Conklin Pilot in the Athabasca oil sands in Canada, the Company has been producing partially upgraded bitumen since 2006. At our Kerrobert Project in Saskatchewan, we have been producing from a heavy oil reservoir since early 2010. We are currently developing a commercial project at Kerrobert by drilling an additional 10 THAI® well-pairs. We are also in the planning and approval stages for an oil sands project on our May River Property and expect to initiate a two well-pair heavy oil pilot project on our Dawson Property in the Bluesky formation.

THAI® Technology

THAI® is the Company's patented evolutionary in-situ combustion technology for the recovery of bitumen and heavy oil that combines a vertical air injection well with a horizontal production well. THAI® integrates existing proven technologies to create a step change in the sustainable development of heavy oil resources globally. During the process, a high temperature front is created from the combustion/gasification of a portion of the oil in the reservoir. This reduces the viscosity of the oil, mobilizing the remaining oil ahead of the combustion front and enabling it to flow by gravity and pressure differential into the horizontal production well. The combustion front sweeps the oil from the toe to the heel of the horizontal producing well, recovering up to an estimated 70-80 percent of the exploitable bitumen-in-place while partially upgrading the crude oil in-situ. CAPRI® is an enhancement to THAI®, which adds a catalyst around the horizontal production well to increase the in-situ upgrading effect. The THAI® and CAPRI® technologies were acquired in 2003 by Petrobank and are held in Petrobank's wholly-owned subsidiary, Archon, which controls all intellectual property rights to the THAI® process and related enhancements, including the patented CAPRI® technology.

One of the expected benefits of THAI® is partial upgrading of the produced oil in-situ. At Conklin, we have consistently produced upgraded bitumen to between 10 and 15 degrees API from a native API of 8 degrees API. Viscosity is also consistently reduced from a native viscosity of more than 500,000 centipoises to less than 2,000 centipoises, with lower viscosity seen in the more upgraded production. At Kerrobert, produced oil has been consistently upgraded in-situ by 4 to 7 degrees API from the native 10 degrees API oil. This upgrading has been recognized by McDaniel at Kerrobert in the McDaniel Report through an oil sales price forecast that is approximately 10% higher than that for native quality oil. One of the unique aspects of the oil produced by the THAI® process is the absence of difficult emulsions, and there is a clean oil/water separation process, eliminating the need to add diluent at surface to achieve an uncontaminated oil water separation.

We believe that THAI® has many potential benefits over competing in-situ thermal recovery methods, including the following:

Potential Operational and Economic Benefits

- Higher potential resource recovery, projected at 70 to 80 percent of exploitable bitumen-in-place in the oil sands based on laboratory tests and field scale numerical simulation
- Ability to operate in lower quality reservoirs inaccessible by steam-based recovery processes
- Lower capital and operating costs compared to steam-based recovery processes
- Shorter construction period due to less extensive surface facilities compared to steam-based recovery processes
- Negligible consumption of natural gas and water with certain projects anticipated to be net water producers
- Partially upgraded produced oil
- Reduced diluent requirements for transportation
- Energy self-sufficient in larger THAI® projects through the utilization of produced gas for power generation

Potential Environmental Benefits

- Lower greenhouse gas emissions compared to steam-based recovery process because the THAI® process does not use natural gas to generate steam after air injection is started
- Minimal use of groundwater and natural gas
- Reduced surface facilities footprint because the THAI® process does not require large water handling facilities that steam-based recovery processes use
- High quality produced water with potential industrial uses
- CO_2 capture ready facilities

THAI® Process Steps

Pre-Ignition Heating Cycle ("PIHC")

At start-up in a bitumen reservoir, the horizontal and vertical wells are steamed for a short period of time to heat both the horizontal production well and vertical injection well. This facilitates mobility around the vertical well, conditioning the reservoir prior to air injection. In a conventional heavy oil reservoir only the vertical injection well requires the PIHC. The time period for the pre-ignition heating cycle will vary depending on the quality of the oil, ranging from 60 to 90 days for bitumen reservoirs and approximately 20 to 60 days for conventional heavy oil reservoirs.

Combustion Initiation

Immediately after the conclusion of the PIHC, air is injected into the reservoir, auto-igniting the oil and creating a high temperature combustion zone. Temperatures in that zone range from four hundred to seven hundred degrees Celsius. The hot combustion gas that is produced contacts the cold oil in front of the combustion zone, causing the lighter oil fractions to be mobilized and the heaviest fractions to be deposited onto the reservoir sand as hydrocarbon coke. The deposited coke is the fuel for the ongoing combustion reaction. The hot bitumen, partially upgraded lighter bitumen and vaporized reservoir water are drained by gravity and are swept into the horizontal well to the surface by the combustion gas due to the difference in pressure between the horizontal well bore and the surface.

Steady State

As air injection continues, the oil drainage front broadens and a continuous air bank is established, with production anticipated to reach peak levels approximately one year after first air and to stabilize for several years thereafter. At steady state, the shape of the oil drainage front is constant and moves from toe to heel orientated by the lower pressure zone along the production well, enabling control of the oxygen flux and assuring that the high-temperature oxidation (combustion) process predominates.

End State

Once the front edge of the drainage volume reaches the heel of the horizontal producer, the wells will decline rapidly but may remain in production at low rates for a significant period of time as the oil in the heated reservoir continues to drain into the production wells. The region behind the burning front is almost completely swept of oil, yielding the high recovery factors anticipated with the THAI® process.

THAI® Applicability in the Canadian Oil Sands

The Canadian oil sands are one of the world's largest accumulations of hydrocarbons. Located in north eastern Alberta, the oil sands underlie approximately 140,000 square miles and contain bitumen, a thick molasses-like hydrocarbon which requires significant upgrading or diluent to be marketable. The Company's Conklin Pilot and May River Property are situated in the heart of the in-situ oil sands development fairway.

Challenges of the Canadian Oil Sands

The bitumen contained in the Canadian oil sands is immobile and cannot be conventionally produced by drilling standard vertical or horizontal wells. Shallow oil sands reservoirs (> 75m to surface) must be produced by employing open-pit mining methods; when the bitumen is too deep to mine (> 250m), referred to as in-situ reservoirs, heat must be added to reduce the viscosity of the oil to be able to produce it to surface via production wells. The most common method for adding heat is to inject steam in to the reservoir. In-situ combustion is an alternative method that also generates significant heat in the reservoir.

To date, SAGD and CSS have been utilized as the primary methods for in-situ recovery. They apply heat to the reservoir by injecting steam to mobilize the bitumen so that it can then flow in to a production well. These steam-based processes can typically recover 20 to 50 percent of the bitumen in place. SAGD involves drilling one horizontal well with a stand off from the bottom of the reservoir of approximately 5 metres and a second horizontal steam injection well 3 to 5 metres above the production well. The steam rises, mobilizing the bitumen which drains into the lower horizontal well and is then pumped to surface. CSS uses one vertical well to inject steam for a period of time, after which the mobilized bitumen and condensed water can be pumped to surface using the same well. In CSS the steam is injected at a high pressure, often high enough to fracture the reservoir rock, and the steam injection and oil production is repeated over many cycles. Steam processes are energy intensive with significant environmental impact as large amounts of water are required to generate the steam and substantial volumes of greenhouse gases are emitted during the burning of natural gas and other hydrocarbon fuels.

THAI® Applicability

The geology of the Canadian oil sands resource is variable and is a major influence in the performance of any recovery technology. Both CSS and SAGD operate best in relatively homogeneous oil sands reservoirs, which make up an estimated 10 percent of the entire oil sands resource base, and typically achieve recovery factors of 20-50 percent of the bitumen in place. THAI®, however, has the potential to

recover up to 70-80 percent of in-place resources. We believe that THAI® could also be applied to previously steamed reservoirs to recover residual resource.

The major challenges to the recovery process in the oil sands include: the thickness of the bitumen zone; the presence of bottom water, top water and/or top gas, which can act as thief zones for heat; large shale lenses that act as barriers for steam migration, and lower pressure reservoirs.

We believe that THAI® has the potential to operate in poorer quality reservoirs as it is less impacted by these geologic variables. Thinner reservoirs can be a target for THAI® as the production well can be placed closer to a bottom water contact and only one horizontal well is required compared to two horizontal wells with SAGD. The THAI® process operates at very high temperatures and creates pressure differential in the reservoir. As a result of the heat and pressure regime created by the THAI® process, the presence of top or bottom water, which act as heat thief zones and are less of a concern, heat can penetrate around the potential barriers caused by shale lenses, and higher recovery factors can be generated in lower pressure reservoirs. With more resource to exploit and a greater recovery factor, we believe THAI® provides a more appealing method of production.

THAI® Applicability in Conventional Heavy Oil

Conventional heavy oil is mobile at reservoir conditions because it is less viscous and has a lower density than bitumen, and it can therefore be cold produced with vertical or horizontal wells. Recovery factors for conventional heavy oil are very low, at five to 10 percent, leaving approximately 90 percent of the oil initially-in-place unrecovered.

In Alberta and Saskatchewan there is an estimated twenty billion barrels of heavy oil resource; of which only five percent is estimated to have been produced. The reservoirs are primarily channel and regional blanket sands with heavy oil quality ranging from 10 to 15 degrees API and viscosity less than 100,000 centipoises, compared to oil sands bitumen at 7 to 10 degrees API and one million centipoises.

There is also an enormous volume of conventional heavy oil resources worldwide that we believe could potentially be produced using the THAI® technology.

Conklin Pilot

Petrobank, through Whitesands, has a 100 percent working interest in 62 sections (39,680 net acres) of oil sands leases, referred to herein as the May River Property, located at Townships 76-78 Ranges 8-10 W4M near the Hamlet of Conklin, Alberta. The oil sands bitumen deposit is contained within the cretaceous-aged McMurray filled valley sandstone at a depth of 350 to 400 metres. The May River Property is comprised of Crown leases with 15-year primary terms. Certain of the leases expire in 2015, with additional expires occurring in 2017 and 2021. With commercial development, the leases can be held by Whitesands indefinitely, as such, the Company does not expect to allow any of the lands comprising the May River Property to expire. Commercial SAGD projects in operation near the May River Property include Statoil Canada Ltd.'s Kai Kos Dehseh project, Cenovus Energy Inc.'s Christina Lake project, Devon Energy Ltd.'s Jackfish project, and MEG Energy Corp.'s Christina Lake project.

Whitesands is utilizing the THAI® process in the oil sands resource on our May River Property. Applications to conduct a THAI® pilot project on the lands were filed with the AEUB and AENV in October 2003, and in February 2004 the Conklin Pilot received approval from the AEUB and AENV. The approval was the culmination of rigorous technical and environmental scrutiny by applicable regulatory authorities.

The Conklin Pilot project was designed around three well-pairs producing to a central facility. Air injection commenced on the first well-pair in July 2006. Air injection on the second well-pair was initiated in January 2007 and on the third pair in June 2007. The wells each demonstrated the same start up characteristics. Modifications to the surface facilities, including enhanced sand handling capability, as well as wellhead and choke enhancements, improved the operations of the surface facilities to deal with the volumes of produced sand from the initial production wells.

On April 1, 2005, the Company announced that TPC had committed to invest up to $9.0 million towards the development and field demonstration of the THAI® technology at the Conklin Pilot. Upon commercialization of THAI® technology, TPC will be entitled to a royalty based on three separate revenue streams. The first stream is based upon 3 percent of Conklin Pilot revenue earned after January 1, 2006 with initial payments starting May 1, 2010. The second stream is based on 0.6 percent of Whitesands revenues (excluding Conklin Pilot project revenues) earned after January 1, 2009 with initial payments starting May 1, 2010. The third stream is based on 3 percent of all third party THAI® licensing revenues earned after January 1, 2008 with initial payment starting May 1, 2009. If, as of December 31, 2017, the cumulative royalty paid from the three royalty streams has not reached or exceeded $26.2 million, royalty payments will continue until $26.2 million has been paid or until December 31, 2022, whichever occurs first.

On June 11, 2007, the Company closed the acquisition shares of its Whitesands Insitu Inc. subsidiary from minority shareholders for $120 million, increasing Petrobank's ownership of Whitesands Insitu Inc. from 84% to 100%. The acquisition was funded entirely by cash on hand. This acquisition was completed pursuant to the terms of the Unanimous Shareholders Agreement ("**USA**") governing the original investment. Subsequent to the transaction, the minority shareholders disputed the price paid for the acquisition of the minority interest under the terms of the USA. This dispute was settled through a lawsuit in favour of the minority shareholders and an additional $20 million was paid by Petrobank to the minority shareholders. The minority shareholders of Whitesands Insitu Inc. initially acquired their 16% interest in Whitesands Insitu Ltd. and three million common shares of Petrobank at a cost of $23.7 million, in April 2005.

On November 14, 2007, Whitesands received a $10 million grant, from the Government of Alberta, in the form of a Crown royalty credit. This program is administered by Alberta Energy's Innovative Energy Technologies Program ("**IETP**"). The IETP represents a $200 million commitment over five years by Alberta Energy to provide royalty adjustments to a number of specific pilot and demonstration projects that use innovative technologies to increase recoveries from existing reserves and encourage responsible development of oil, natural gas and in-situ oil sands reserves. IETP is also designed to provide funding for industry to find commercial technical solutions to the gas over bitumen issue that will allow efficient and orderly production of both resources.

In December 2007, the Company completed a 4D seismic survey over the current Conklin Pilot site, which provided confirmation of the combustion zone development. A further 4D seismic survey was completed in December 2008 and this survey also confirmed the process in the reservoir is progressing from the toe of the production well towards the heel. In 2009, a third 4D seismic survey was initiated over the project area, the results of which further confirmed the extent of the combustion zone and its toe to heel movement. During 2010 we acquired a fourth timelapse (4D) survey over the pilot area. All of these 4D's confirm that the movement of the combustion front is from toe-to-heel.

The P3B replacement well at the Conklin Pilot was completed during the third quarter of 2008.This well replaced the P3 horizontal well and was designed to demonstrate the additional upgrading potential in our CAPRI® process. In laboratory tests, CAPRI® has achieved an upgrading effect of seven degrees API beyond the upgrading effect resulting from the THAI® process. The P3B well also incorporated a

narrower slot design, intended to significantly reduce the elevated level of sand production originally experienced in the first three production wells. The initial operations on the P3B well had lower sand production and demonstrated the improvements of a narrower slotted liner design but it did not quite solve the sand issue. In P1 and P2 we did see a reduction in produced sand through the adoption of surface de-sand vessels, which resulted in improved on-stream factors. However, despite these minor operational improvements, these wells still posed major operational challenges and, as a result, were re-drilled in 2009. We effectively shut-in the majority of our production from August to November to facilitate the re-drilling, and the P1B and P2B replacement wells were placed on production at the end of 2009. Both wells were completed with a FacsRite™ liner which utilizes multi-screen cartridges rather than slots but with similar sand control spacing as in P3B. This configuration provides for better liner strength, improved sand control and the capacity to have more open hole facilitating increased production flow. Although initial production from the wells was encouraging, we were not able to establish full communication with the combustion zone which required additional steam cycling. We did, however, produce upgraded oil indicating that the production was the product of the combustion process. We believe that communication with the combustion zone may have been negatively impacted by channeling into the initial wells P1 and P2.

During operations produced oil quality has consistently averaged approximately 12 to 15 degrees API, compared to the native eight degree API bitumen in-situ. We have also recovered a light oil condensate stream in the secondary separators that was carried in the vapour phase by the overhead gas system and condensed out in the secondary separators. This lighter oil can be over 30 degrees API and analysis has indicated that this stream could be up to 10 percent of the total produced hydrocarbons. This lighter oil component further demonstrated significant in-situ thermal cracking and the potential for co-production of other high-value by-products.

Thus far the Conklin project has proven the operational effectiveness of THAI® in a bitumen reservoir. The project has confirmed that we can ignite and sustain high temperature combustion and, with the use of 4-D seismic, we have been able to establish that the combustion front progresses along the wellbore from toe-to-heel. We have also demonstrated the ability to manage and control the combustion front and the overall safe operation of the THAI® process. After some initial challenges with sand production, we deployed FacsRite™ liners in two wells, which overcame the problem and is now being incorporated in to all our future THAI® well designs. The Conklin Pilot has also demonstrated that the process is operationally robust and that the process produces in-situ upgraded oil that can attract a premium field price compared to native oil. The original well design and surface facilities at Conklin have provided excellent prototype modeling for current design enhancements which we are employing in all of our new facilities.

Unfortunately, the original wells are now sub-optimal for continued operation. The P2B well experienced a failure of the instrument string and attempts to retrieve it resulted in damage to the well bore necessitating its abandonment in the first quarter of 2011. During that time, we used the service rig to abandon P1, which was previously suspended. These wells were originally drilled using an earlier well configuration which we do not intend to use in the future. In addition, the localized reservoir at Conklin remains a challenge as it is of poorer quality with relatively thin basal sand sections (five to eight metres) in the toe area of the wells, resulting in low initial sustainable production rates. The reservoir quality improves closer to the heel of the wells to over 15 metres of basal sands. We are reviewing options to utilize Conklin as a field testing facility for technology enhancements, which may include drilling new injector and production wells in better parts of the reservoir.

May River Project

The May River project is the planned commercial development of the May River Property west of our Conklin Pilot. The project will build on the experience we gained at the Conklin Pilot and Kerrobert Project and is intended to be completed in phases. With initial production capacity of 10,000 barrels of THAI® oil per day, its ultimate capacity is anticipated to be as much as 100,000 bopd.

The regulatory application for May River's first phase was filed with the ERCB and AENV at the end of 2008. The application has been deemed complete and is now moving through the regulatory process. We received supplementary information requests ("**SIRs**") from the ERCB and AENV in mid 2009, which were responded to in December 2009. A second set of SIRs were received January 2010 from AENV and were responded to in February. Draft approval from AENV, which is conditional on receiving ERCB approval, was received on April 12, 2010. A third round of supplemental information requests was received from the ERCB and responded to in early 2011. We are still awaiting ERCB approval.

The front end engineering and design ("**FEED**") for the project was completed late in 2009. The design incorporates power generation utilizing low energy produced gas, sulphur recovery, is CO_2 capture ready, and is expected to be a net water producer rather than a water user, which would make it a leading environmentally sustainable process for oil sands and heavy oil development. The project will utilize a modular approach that is designed to be installed and operated in heavy oil fields world-wide.

The May River project is currently in the final detailed engineering phase, and orders have been placed for some long lead time equipment, including power generation turbines and air compression. Upgrades to the existing roads have been completed, along with other infrastructure work that can be accomplished prior to receiving final regulatory approval.

We plan to drill 12 to 17 stratigraphic wells on our leases in 2011 to further evaluate additional resource potential, optimize well placements for the 18 well-pairs planned for the potential 10,000 bopd development and further delineate the resource for future expansion phases of the May River project.

Glover Property

In the second quarter of 2007, we acquired the Glover Property. The Glover Property is located approximately 6.5 kilometres south of the May River Property. These leases will be further evaluated in the future as our focus will be on the May River Property and Kerrobert Project. No work has been conducted on our Glover Property since 2008.

Kerrobert Project

Late in the fourth quarter of 2008, we entered into royalty, technology license and joint operating agreements with True Energy Trust to apply Petrobank's patented THAI® process on portions of their Kerrobert heavy oil property in west central Saskatchewan. In June 2009, Baytex acquired certain oil and gas assets from True Energy Trust, including the joint venture and license agreements. Following this acquisition, Baytex was novated into the joint venture and license agreements with Petrobank, with some minor modifications.

Under the original agreements, Petrobank earned a 50% working interest in four sections of land in the Kerrobert Mannville heavy oil pool, and Petrobank and Baytex agreed to develop a two-well project to demonstrate the THAI® technology in a 20+ metre thick conventional heavy oil reservoir. On September 30, 2010, Petrobank acquired Baytex's 50% working interest in the Kerrobert Phase-1 project lands and wells, consisting of the two-well pilot project and approximately 1,300 net acres of land. Baytex retained a gross overriding royalty on its working interest in the Phase-1 lands, commencing 12 months after first production from the Kerrobert expansion project.

The existing Joint Venture Agreement with Baytex remains in place for the Phase-2 lands, discretionary lands, and the area of mutual interest. Petrobank will have the option to conduct additional projects on the Phase-2 lands (consisting of 6.25 sections). Upon electing to commence an additional project, Petrobank will be assigned a 50% working interest in the sections on which the project is conducted. In addition, Petrobank and Baytex established an area of mutual interest over 30 additional sections of land to jointly develop additional THAI® projects.

Petrobank filed a regulatory application for the two well-pair project with the Saskatchewan regulatory authorities on May 15, 2009, which was approved on July 9, 2009. Construction was completed and air injection was initiated by the end of October 2009.

Petrobank filed a regulatory application to expand the Kerrobert facility in the second quarter of 2010. Regulatory approval was received on August 6, 2010 and construction began late in the third quarter. The Phase-1 expansion includes an additional 10 THAI® well-pairs and associated surface facilities. The start-up pre-heat ignition cycle began on the first well pad on March 6, 2011. Air injection and production are expected to begin during Q2 2011 and all 10 wells are anticipated to be on production by July 2011. The expansion has a design capacity of 7,200 bopd and we expect to reach steady state production within approximately one year.

Dawson Project

The Dawson project is located near Peace River, Alberta within a significant heavy oil resource in the Bluesky formation. The Company acquired a 50% interest in the Dawson Property and entered into a license and royalty agreement with Duvernay Oil Corp., with respect to our first Alberta-based, third party THAI® license. In August 2008, Shell Canada Limited acquired Duvernay Oil Corp and, during the fourth quarter of 2010, Petrobank acquired Shell's 50% working interest in the Dawson project and a 100% working interest in an additional 27 sections (17,280 acres) of land prospective for heavy oil resource adjacent to the Dawson project.

We anticipate that the Dawson project will demonstrate the THAI® process in a third reservoir type. The Bluesky bitumen reservoir at Dawson is similar to the McMurray reservoir at Conklin, Alberta, except that it can be cold produced. Conventional production in the Bluesky reservoir generally results in very low recovery factors, similar to the conventional heavy oil recovery factors at Kerrobert, Saskatchewan.

The upper portions of the Bluesky formation contain 10 degree API heavy oil, comparable to other conventional heavy oil reservoirs throughout western Canada. The pilot project scope consists of two well-pairs and our simplified surface facility design. In August 2008, a stratigraphic well was drilled on the project site that will be used as a thermal observation well during the project's operating phase. The regulatory application for this project was filed on April 2, 2009 contemplating a project of similar scope and scale to our initial two well-pair Kerrobert pilot project. ERCB approval was received on October 28, 2010 and final AENV approval was received on November 23, 2010 for the initial two well-pair THAI® project.

The initial Dawson project will be substantially similar to the initial two well Kerrobert project, consisting of two THAI® well-pairs plus associated surface facilities. The current surface facilities at Kerrobert will be transferred to Dawson once we have incorporated the first two Kerrobert wells into the new expansion facilities. We anticipate work on this initial project at Dawson to begin during the second quarter of 2011 and the pre-ignition heating cycle to commence during the third quarter.

Plover Property

Petrobank acquired 3.5 sections (2,269 acres) of land in a Saskatchewan Crown land sale in late 2010. The lands are located in the Plover area of Saskatchewan on the same trend as the Kerrobert project. We plan to purchase or shoot 3-D seismic and drill a stratigraphic well in 2011 to further define the resource potential.

Sutton Creek Property

In the third quarter of 2007, we acquired a township of land comprised of 36 square miles (23,040 acres) with oil sands potential at Sutton Creek, Saskatchewan. This land position is located within a promising Saskatchewan oil sands fairway. In 2008, we acquired 35 kilometres of 2D seismic on our 23,040 acres of oil sands lease in northwest Saskatchewan. No additional work has been conducted on the Sutton lands since 2008. We will continue to evaluate the future potential of the land as an exploration project. Currently no wells are planned to be drilled.

Intellectual Property

The Company indirectly owns the patents and other intellectual property rights to the THAI® and CAPRI® technologies (the "**Technologies**") through Petrobank's wholly-owned subsidiary, Archon. Whitesands has royalty free use rights to the Technologies and any future third-party (non-Petrobank) licensing royalties generated by Archon are subject to a 17.5 percent net profits interest payment (see "*Interest of Management and Others in Material Transactions*"). Each of THAI® and CAPRI® have trademark registrations in Canada, the United States, and certain other countries around the world for use in association with the Technologies.

Research and development activities are conducted under two wholly-owned subsidiaries of Petrobank, Archon and Archon Technologies International Inc. Proprietary laboratory facilities were established in 2005 and Archon is playing an increasingly important role in the development of new technologies and enhancements to the THAI® process, as well as the evaluation of complementary technologies. Ongoing activities include the advancement of CAPRI®, which adds a catalyst around the horizontal production wells to increase the upgrading effect in-situ concurrent with the THAI® combustion process. Archon also performs a vital function in the ongoing evaluation of all our projects by analyzing produced gases, water and oil, as well as generating solutions to operating issues as they arise. This creates valuable operational know-how and intellectual capital in the Technologies.

In early 2010, Archon was granted two new U.S. patents, for previously filed patent applications covering improvements that add novel features to Archon's existing THAI® and CAPRI® technologies. These new patents enable pressure and temperature control in the horizontal producer as well as the co-injection of oxygen and CO_2 that combines the benefits of thermal and solvent flooding. In addition, these patents extend the life of our existing intellectual property to 2026. Archon was granted additional patents in Russia and Mexico during the fourth quarter of 2010 and first quarter of 2011, respectively. Further research is continuing and we expect field scale testing of new concepts during 2011, such as enriched oxygen injection and direct oxidation of sulphur in produced gas. One major patent issued in 2010 was

for a heel to toe propagation of the combustion front- this process reduces the surface footprint drastically and eliminates need for a separate injection well at the toe as used in conventional THAI® process.

One new patent application incorporating a major step change in combustion technology was filed late in 2010 with patent pending. All Archon patents are filed under the Patent Cooperation Treaty and we currently have eight patents issued or pending in 36 countries. Archon continues to develop additional patentable intellectual property to further enhance and expand the effectiveness of our core THAI® and CAPRI® technologies.

GENERAL INFORMATION ABOUT THE BUSINESS

Employees

As at December 31, 2010, Petrobank has 76 employees and PetroBakken has 300 employees.

Specialized Skill and Knowledge

The Company believes its success is dependent on the performance of its management and key employees, many of whom have specialized knowledge and skills relating to oil and gas operations. The Company believes that it has adequate personnel with the specialized skills required to successfully carry out its operations.

Environmental, Safety and Social Responsibility

Environmental Regulation

All phases of the oil and natural gas business present environmental risks and hazards and are subject to "cradle to grave" environmental regulation pursuant to international conventions and national, provincial, and municipal laws and regulations. Environmental legislation governs all aspects and phases of oil and gas development, from planning and construction, through operations and onto final abandonment and reclamation. All jurisdictions have restrictions and prohibitions for spills, releases, discharges, or emissions of various substances produced or used in association with oil and natural gas operations, as well requirements for oilfield waste handling and storage, habitat protection, and setbacks of oil and natural gas activities from fresh water bodies, buildings and urban centers.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act*. This legislation enables numerous regulations, guidelines and codes of practice, which impose strict environmental standards relating to the release of substances and the protection of species, habitat and land capability in the province and include monitoring and reporting obligations that carry significant penalties for non-compliance.

Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the *Environmental Management and Protection Act, 2002* and the *Oil and Gas Conservation Act*, which regulate harmful or potentially harmful activities and substances, any release of such substances, and remediation obligations. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial *Environmental Assessment Act.*

Environmental legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation

can require significant expenditures and a breach may result in the imposition of significant fines and penalties (including imprisonment) or in the suspension or revocation of necessary licences and approvals. The Company may also be subject to civil liability for damage caused by pollution. Certain environmental protection legislation may subject the Company to statutory strict liability in the event of an accidental spill or discharge from a licensed facility, meaning that fault on the part of Petrobank or PetroBakken need not be established if such a spill or discharge is found to have occurred.

Oil sands recovery, pipelines and upgrader projects, and associated electrical facilities, are subject to provincial and federal environmental laws and regulations. Environmental laws and regulations require various approvals and provide for restrictions and prohibitions on releases or emissions of various substances produced or used in association with such projects.

The Corporation may be affected by the Regional Plan for the Lower Athabasca Region (the "**LARP**") under the *Land Stewardship Act* of Alberta once it is finalized. Once finalized, the LARP is expected to incorporate regional thresholds for air emissions, water use, and land disturbance to control cumulative environmental effects of industrial development. Until the LARP is finalized its impacts on our operations, if any, cannot be determined.

Greenhouse Gases and Industrial Air Pollutants

Kyoto Protocol and Copenhagen Accord

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**Convention**") and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other GHGs. Management expects that the Company could eventually be a significant producer of some GHGs covered by the Convention. However, the Government of Canada has concluded that Canada will not meet its commitment to the Kyoto Protocol and has been developing an alternative strategy for reducing Canada's GHG emissions.

From December 6 to 18, 2009, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol, which expires in 2012. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord 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. Although Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review of implementation of its stated goals before 2016.

Government of Canada Regulations

The Government of Canada previously released the Regulatory Framework for Air Emissions, updated March 10, 2008 by Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions (collectively, the "**Regulatory Framework**"), for regulating GHG emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. In 2009, the Government of Canada announced its commitment to work with the provincial governments to implement a North American-wide 'cap and trade' system for GHG emissions, in

cooperation with the United States. On January 30, 2010, the Government of Canada announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with U.S. policy.

The Government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether either federal GHG regulations or an integrated North American 'cap and trade' system will or will not be implemented, or what obligations might be imposed under any such system. As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on the Corporation's operations cannot be determined at this time.

Government of Alberta Regulations

Alberta currently regulates GHG emissions under the Climate Change and Emissions Management Act, the *Specified Gas Reporting Regulation* (the "**SGRR**"), which imposes GHG emissions reporting requirements, and the *Specified Gas Emitters Regulation* (the "**SGER**"), which imposes GHG emissions limits. Under the SGRR, GHG emissions of 100,000 tonnes or more from a facility in any year must be reported to Alberta Environment. Alberta Environment has publicly announced its intention to lower this reporting threshold for facilities to 50,000 tonnes of GHG emissions annually. The SGER applies to facilities in Alberta that have produced 100,000 or more tonnes of GHG emissions in 2003 or any subsequent year and requires reductions in GHG emissions intensity (i.e. the quantity of GHG emissions per unit of production) from emissions intensity baselines that are established in accordance with the SGER. The SGER distinguishes between "established" facilities that completed their first year of commercial operation before January 1, 2000, or have completed eight years of commercial operation, and "new" facilities that have 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. Generally, the baseline for an established facility reflects the average of emissions intensity in 2003, 2004, and 2005, and for a new facility emissions intensity in the third year of commercial operation. For an established facility, the required reduction in GHG emissions is 12% from its baseline, and such reduction must be maintained over time. For a new facility, the reduction requirement from its baseline is phased in by annual 2% increments beginning in the fourth year of commercial operation until the maximum 12% reduction requirement imposed on established facilities is reached. There are three ways to comply with reduction requirements: (i) actual physical reductions in GHG emissions intensity; (ii) purchase of Alberta based emission offset credits and/or emission performance credits; or (iii) purchase of fund credits at a cost of $15 per tonne of GHG emissions, with the proceeds going to the Government of Alberta's Climate Change and Emissions Management Fund. Compliance reports for facilities subject to the SGER are due to Alberta Environment on March 31 annually. The Government of Alberta has previously announced in its 2008 Provincial Energy Strategy that it may modify the SGER towards stricter standards. In addition, Alberta facilities must currently report emissions of industrial air pollutants and comply with obligations imposed in permits and under environmental regulations.

British Columbia Regulations

The *Greenhouse Gas Reduction (Cap and Trade) Act* and its Regulations set out the requirements for greenhouse gas emissions reporting in British Columbia. The data collected supports the inventorying of provincial emissions and assists in the development, implementation and evaluation of climate action policy. Beginning on January 1, 2010, facilities emitting 10,000 tonnes CO^2 equivalent or more are required to report by March 31 of the following year, and those emitting 25,000 tonnes or greater are required to have reports verified by a third party. Emissions include flaring and carbon dioxide from

natural gas fuel consumption. From initial review of fuel consumption at PetroBakken's three BC facilities, the requirement to report 2010 data is anticipated.

The Future of GHG Emission Regulations

There will most certainly be a financial impact of GHG emission regulation on oil and gas industry participants and their projects, particularly with respect to the development of Alberta's oil sands. However, however the extent of that impact is not yet known. In particular, there is uncertainty regarding the ultimate GHG emission regulatory regime that will be applicable to the Company due to a variety of factors, including the potential for changes to the regulation of GHG emissions and the potential for the harmonization of GHG emission regulatory regimes across various jurisdictions which may impact the Company's operations.

At present, there is no assurance that any new regulations implemented by the Government of Canada relating to the reduction of GHG emissions will be harmonized with the Government of Alberta's GHG emissions reduction regulations. In such case, the costs of meeting new federal government requirements could be considerably higher than the costs of meeting Alberta's current requirements.

Trends

The operations of Company are, and will continue to be, affected in varying degrees by laws and regulations regarding environmental protection. We believe that it is likely that the trend in environmental legislation and regulation will continue toward stricter standards. It is impossible to predict the full impact of these laws and regulations on our operations. It is not anticipated that our competitive position will be adversely affected by current or future environmental laws and regulations governing its current oil and gas operations. No assurance can be given, however, that environmental or safety laws or regulations will not result in a curtailment of production, a material increase in the costs of production or development or exploration activities or otherwise adversely affect our projects, financial condition, capital expenditures, results of operations, competitive position or prospects. The Company is committed to meeting its responsibilities to protect the environment and the safety of its workers in all areas where it conducts operations and will take such steps as required to ensure compliance with environmental and safety legislation.

Environment and Community Values and Commitment

PetroBakken

Central to PetroBakken's values is our commitment to the protection of people, the environment and the communities where we operate. This commitment from each of our employees drives our planning and actions. Worker safety and health are the shared responsibility of the Company and our employees. The Company ensures procedures, processes and training are in place and employees use these tools responsibly. As a team we manage safe operations.

PetroBakken personnel are aware of the importance of safe operations and our people have in-depth skills to manage worker and environmental protection. While we are active implementing our development plans, every employee is mindful of our values to be good stewards of land, air, water, wildlife and people.

We recognize that our operations have an impact on the environment and we attempt to minimize this impact by following best practices. To ensure sustainability, we must respect our natural environment

and ensure our operations are carefully managed. Our employees live and work in the community, and are aware of their commitment.

Our employees are our local representatives in the community. In every community in which we operate, it is our desire to be a welcomed neighbour. We encourage our people to be engaged with the community and create awareness of our operations. We believe in treating all communities and their members with respect.

PetroBakken allocates a portion of our capital program annually to the abandonment and reclamation of wells and facilities as they reach their economic life. Ongoing environmental obligations are expected to be funded from cash flow.

Heavy Oil Business Unit

Petrobank maintains a Vision and Values statement that sets out our corporate responsibility commitments on environmental sustainability, health, safety and public engagement in those areas where we operate, all within the context of business integrity.

The Heavy Oil Business Unit uses best environmental practices in the planning, design, and implementation of exploration programs and heavy oil production. The objective is to minimize the environmental footprint of our operations and at the same time pursue new technologies which will also contribute to this objective.

We are committed to providing a healthy and safe working environment for employees, contractors and the general public. This is supported by dedicated staff and contractors who provide on-site health and safety support as well as ongoing hazard assessments, annual audits and training programs. Emergency response planning is integrated into all projects. On December 31, 2009, the Conklin THAI® Project surpassed 1,300 days without a Lost Time Accident (LTA) and we completed 2010 without any LTAs at Conklin or Kerrobert demonstrating our commitment to achieving even greater future milestones.

The Heavy Oil Business Unit is proactive in its communications with the local communities in Alberta and Saskatchewan where we are actively exploring or developing projects. The goal is to establish an open and fair consultation processes with all stakeholders, provide information on local business and employment opportunities, identify areas of interest or concern and develop mutually beneficial working relationships. We began a successful public engagement program in the Wood Buffalo region in 2003 as part of the planning and regulatory approval work for the Conklin Pilot. This program has been expanded to include the May River project, to ensure that both our regulatory compliance and our delegated procedural aspects of consultation requirements are met as well as to maintain established working relationships with directly affected stakeholders in the region.

Policies and Procedures

Monitoring and reporting programs for environment, health and safety ("**EH&S**") performance in day-to-day operations, as well as inspections and assessments, are designed to provide assurance that environmental and regulatory standards are met. We maintain an active comprehensive integrity monitoring and management program for our surface piping, facilities, storage tanks and underground pipelines. Contingency plans are in place for a timely response to an environmental event and abandonment, remediation and reclamation programs are in place and utilized to restore the environment. We also perform a detailed due diligence review as part of the acquisition process to determine whether the acquired assets are in regulatory and environmental compliance and asses any liabilities with respect thereto. The Company expects to incur abandonment and site reclamation costs as existing oil and gas

properties are abandoned and reclaimed. In 2010, expenditures for normal compliance with environmental regulations as well as expenditures beyond normal compliance were not material and we do not expect such expenditures will be material in 2011. Based on current estimates and excluding salvage value, the total anticipated undiscounted future cost of abandonment and reclamation costs to be incurred over the life of the reserves is estimated at approximately $18.4 million for the HBU and $204.8 million for PetroBakken. As at December 31, 2010, the HBU has recorded an asset retirement obligation of $6.0 million and PetroBakken has recorded an asset retirement obligation of $60.3 million in each case, based on a discount rate of 8%. See "*Other Oil and Gas Information – Additional Information Concerning Abandonment and Reclamation Costs*".

Management of the Company is responsible for reviewing the Company's internal control systems in the areas of health, safety and environment and our strategies and policies regarding health, safety and the environment, including our emergency response plan. Management reports to the Board of Directors on a quarterly basis with respect to environment, health and safety matters, including: (i) compliance with all applicable laws, regulations policies with respect to health, safety and the environment; (ii) on emerging trends, issues and regulations related to health, safety and the environment that are relevant to the Company; (iii) the findings of any significant report by regulatory agencies, external health, safety and environmental consultants or auditors concerning performance in health, safety and the environment; (iv) any necessary corrective measures taken to address issues and risks with regards to our performance in the areas of health, safety and the environment that have been identified by management, external auditors or by regulatory agencies; (v) the results of any review with management, outside accountants, external consultants and legal advisors of the implications of major corporate undertakings such as the acquisition or expansion of facilities or decommissioning of facilities; and (vi) all incidents and near misses with respect to the Company's operations, including corrective actions taken as a result thereof. Management of PetroBakken reports to its board of directors in respect of the foregoing matters and provides EH&S reporting to the Petrobank board of directors on a quarterly basis.

INDUSTRY CONDITIONS

Industry Conditions in Canada

The oil and natural gas industry is subject to extensive controls and regulations to govern its operation, which include exploration, development, production, marketing, transportation, and refining. These controls and regulations are imposed by legislation enacted by various levels of government. In addition, pricing and taxation of oil and natural gas is governed by agreements among the governments of Canada, British Columbia, Alberta, Saskatchewan, and Manitoba. It is not expected that any of these controls or regulations will affect the operations of the Company in a manner materially different than they would affect other oil and gas companies. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted.

Land Tenure

Crude oil and natural gas located in Alberta, British Columbia, Saskatchewan and Manitoba are owned predominantly by the respective provincial governments, generally termed the "Crown". Provincial governments grant rights to explore for and produce oil and natural gas under leases, licenses and permits with terms generally varying from two years to five years and on conditions contained in provincial legislation. Leases, licenses and permits may be continued indefinitely by producing under the lease, license or permit. Some of the oil and natural gas located in these provinces is freehold (privately owned) and rights to explore for and produce oil and natural gas are granted by the mineral owners on negotiated terms and conditions. For information relating to land tenure with respect to the Company's Heavy Oil Business Unit, see "*Heavy Oil Business Unit Overview*".

Pricing and Marketing – Crude Oil

In Canada, producers of oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of crude oil. The price depends in part on the oil type, the quality, prices of competing fuels, distance to market, the value of refined products and the supply/demand balance. Oil exports may be made pursuant to export contracts with terms not exceeding one year in the case of crude oil other than heavy crude oil, and not exceeding two years in the case of heavy crude oil, provided that an order approving any such export has been obtained from the National Energy Board ("**NEB**"). Any crude oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export license from the NEB and the issue of such a license requires the approval of the Governor in Council.

Pricing and Marketing – Natural Gas

In Canada, natural gas is sold throughout the country at various market hubs, which are connected to pipelines within Canada and the United States. The transaction price is determined by negotiation between natural gas producers, marketers and purchasers, and includes the utilization of electronic trading platforms, various publications and reference indices. Prices depend on many variables including but not limited to supply and demand fundamentals, the price of NYMEX natural gas contracts, distance to alternate markets, pipeline costs, natural gas storage levels, competing fuels, contract terms, weather, and foreign exchange. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters can negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain criteria prescribed by the NEB and the Government of Canada. As in the case with oil, natural gas exported from Canada for a term of two years or less or for a term of between two and 20 years (in quantities of not more than 30,000 10^3m^3 per day) may be made pursuant to a NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of British Columbia, Alberta, Saskatchewan and Manitoba 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.

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, as it applies to trade between Canada and the United States, carries forward most of the material energy terms that are contained in the Canada-US Free Trade Agreement. Subject to the General Agreement on Tariffs and Trade 1994, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, so long as any export restrictions do not:

- reduce the proportion of energy resources exported relative to total supply (based upon the proportion prevailing in the most recent 36 month period or another representative period agreed upon by the parties);
- impose an export price higher than the domestic price (subject to an exception that applies to some measures that only restrict the value of exports), or
- disrupt normal channels of supply to the United States.

Under NAFTA, each of Canada, the United States and Mexico are prohibited from imposing minimum or maximum export or import price requirements, with some limited exceptions.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime in a given province is a significant factor in the profitability of crude oil, natural gas and natural gas liquids production.

Royalties payable on production from lands, other than Crown lands, are determined by negotiations between the mineral freehold owner and the lessee, although production from such lands is also 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.

Government Incentive Programs

The Company has benefited from certain provincial and federal government incentive programs, which have included royalty rate reduction and tax credits (including the Canada Revenue Agency's Scientific Research and Experimental Development Program, Alberta Energy's Innovative Energy Technologies Program, Industry Canada's Technology Partnerships Canada Program, the Saskatchewan Petroleum Research Incentive, amongst others) to encourage oil and natural gas exploration, the development of new technologies or enhanced recovery projects.

Alberta

Producers of oil and gas from crown lands in Alberta are required to make monthly royalty payments in respect of oil and natural gas produced.

On October 25, 2007, the Alberta Government 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 include 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 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% to 50%, an increase from the previous maximum rates of 30% to 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 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/m3 compared to the previous royalty curve.

Royalty rates for the 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 0% to 50%, an increase from the previous maximum rates of 5% to 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 curve.

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.

On April 10, 2008, the Alberta Government introduced two new royalty programs to be implemented along with the NRF and intended to encourage 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 month 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 meter. 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, the Alberta Government announced the introduction of a an optional five-year transitional royalty program ("**Transitional Program**"). The Transitional Program applies to conventional oil and natural gas wells drilled to measured depths between 1,000 and 3,500 m between November 19, 2008 and January 1, 2014. For each well, the producer can make a one-time option to produce the well under the new transitional royalty rates or those outlined in 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. As of 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 Alberta Government introduced the Drilling Royalty Credit Program and the New Well Royalty Reduction Program as an incentive to increase drilling, completion and gathering work on conventional oil and gas wells. The Drilling Royalty Credit is earned at a rate of $200/m of well depth for conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2011. The credits for a company with PetroBakken's production level can be claimed up to 50% per year in years 2009, 2010 and 2011, as long as use of the credit does not reduce the company average Alberta Crown royalty rate to less than 5%. The New Well Royalty Reduction Program applies to all new wells that begin production between April 1, 2009 and March 31, 2011. The program provides for a 5% maximum royalty for the first 12 months of production as long as cumulative produced volume for the well is less than 50,000 barrels of oil or 500 MMcf of natural gas. On March 11, 2010, the Alberta Government announced that the incentive program rate of 5% for the first 12 months of production would be made permanent, with the same volume limitations. This incentive program was further modified on May 27, 2010, as outlined below.

On May 27, 2010, in conjunction with the release of the new royalty curves, the Alberta Government 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 began producing on or after May 1, 2010;
- Horizontal oil 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 began producing on or after May 1, 2010. For wells of less than 2,500 metres, the incentive expires at 50,000 bbls or 18 producing months. These limits increase for deeper wells to a maximum of 100,000 bbls or 48 producing months.

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

Alberta also maintains a royalty reduction program for low productivity oil wells, a royalty adjustment program for deep marginal gas wells and a royalty exemption for re-entry wells, among others.

At PetroBakken's Jumpbush property, within the Siksika Nation, royalties are payable to Indian Oil and Gas Canada, a branch of the Canadian Federal Government. The royalty on oil is paid on a well by well basis according to a sliding scale formula creating a royalty of 20% of the first 4.99 m^3/day plus 35% of the next 10 m^3/day plus 50% of the next 10 m^3/day plus 60% of all production over 24.99 m^3/day. Clean oil trucking costs are allowable deductions. Royalties on natural gas also are paid on sales volumes on a well by well basis according to a sliding scale formula providing for 25% of the first 24.99 10^3m^3/day plus 35% of the next 15 10^3m^3/day plus 50% of volumes over 39 10^3m^3/day. Gathering, processing and compression costs are allowable deductions provided that deductions do not exceed 50% of the gross proceeds of production. All wells at Jumpbush are currently producing <24.99 10^3m^3/day and accordingly pay royalties at the lowest rate.

Alberta - Bitumen

Effective January 1, 2009, the Alberta Government introduced price sensitive formulas which are applied both before and after allowed costs have been recovered. The gross royalty starts at one percent of gross bitumen revenue and increases for every dollar that the world oil price, as reflected by the WTI crude oil price, is above $55 per barrel, to a maximum of nine percent when the WTI crude oil price is $120 per barrel or higher. The net royalty on oil sands starts at 25 percent of net bitumen revenue and increases for every dollar the WTI crude oil price is above $55 per barrel to 40 percent when the WTI crude oil price is $120 per barrel or higher. Prior to the payout of specified allowed costs, including certain exploration and development costs, operating costs and a return allowance, the gross royalty is payable. Once such allowed costs have been recovered, a royalty of the greater of: (a) the gross royalty and (b) the net royalty is payable.

Saskatchewan

In Saskatchewan, crude oil Crown royalties and freehold production tax depend on well productivity, the current market price of oil, the classification and vintage of the oil and the quantity of oil produced in a month. Crude oil is classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil", and the vintage classifications ("fourth tier oil", "third tier oil", "new oil" or "old oil") are applicable to each of these three crude oil types. Generally, the vintage of oil is based on the determination of whether the well was on production before January 1, 1974 ("old oil"), drilled between February 9, 1998 and October 1, 2002 ("new oil"), between January 1, 1974 (April 1, 1991 if horizontal) and January 1, 1994 (October 1, 2002 if horizontal) ("third tier oil"), or after October 1, 2002 ("fourth tier oil"). Newly drilled oil wells in Saskatchewan qualify for "volume based" incentives ranging from 0 to 16,000 m3, depending on the type of well (deep or non-deep, exploratory or development, and horizontal or vertical). Qualifying incentive volumes are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%.

Saskatchewan Crown royalties and freehold production tax on natural gas are price sensitive, depending also on the vintage of the natural gas, the quantity produced in a month, and whether the gas is associated (gas produced from oil wells) or non-associated. The vintage classifications of gas production are "fourth tier gas", "third tier gas", "new gas" and "old gas". Generally, the vintage of gas is based on the determination of whether the gas is produced from a well on production before October 1, 1976 ("old gas"), drilled between October 1, 1976 and February 9, 1998 ("new gas"), between February 9, 1998 and October 1, 2002 (third tier gas), or after October 1, 2002 ("fourth tier gas"). Newly drilled qualifying exploratory gas wells in Saskatchewan qualify for a 25,000,000 m3 "volume based" incentive. The qualifying incentive volume is subject to a maximum royalty rate of 2.5% and a freehold production tax rate of 0%.

The majority of PetroBakken's production in Saskatchewan is "non-heavy oil other than southwest designated oil" with a vintage classification of "fourth tier oil". Saskatchewan royalty payable on this production is 2.5% until 6,000 m3 (37,740 barrels) of oil have been produced.

Production in excess of this threshold is subject to a royalty rate based on well productivity and oil prices. The maximum royalty rate for all fourth tier oil is 30%.

The majority of PetroBakken's gas production in Saskatchewan is "associated gas" which is natural gas produced in association with oil. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate for associated gas is less than on non-associated natural gas. The maximum royalty rate for all fourth tier gas is 30%.

Saskatchewan Crown royalties and freehold production tax on enhanced oil recovery projects such as Petrobank's Kerrobert THAI® Project, provide a Crown royalty of 1% of gross revenues pre-payout and 20% of operating income post-payout, and a freehold production tax of 0% on operating income pre-payout and 8% post-payout.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the vintage of the oil pool discovery (whether the oil was produced from a pool discovered before or after October 31, 1975), whether the oil is considered incremental or produced from a well shut-in for at least 36 months immediately preceding January 1, 1998 and which resumed production on or after such date, the quantity of oil produced in a

month and the value of the oil. Oil produced from pools discovered after June 30, 1974 may be exempt from the payment of a royalty for the first 36 months of production. Subject to minimum royalties described in the following sentence, the royalty payable on natural gas is determined by a sliding scale based on a reference price which is the greater of the amount obtained by the producer and at prescribed minimum price. Gas produced in association with oil has a minimum royalty of 8% while the royalty in respect of other gas may not be less than 15%.

British Columbia Crown natural gas basic royalty, for the example of Base 9 gas typical of new drilling prospects, ranges from 9% to 27%, based on gas price. Low productivity wells, marginal wells and ultra marginal wells will have their royalties reduced and will approach 0% as the production rate approaches zero. During 2008, the Deep Well Program was extended, which provides royalty credits for wells with vertical depths greater than 2,500 m, or for horizontal wells with completion point vertical depth greater than 2,300 m. Royalty credit ranges from zero at 2,500 m to $2.7 million at a depth of 5,500 m for wells located in the East map area of Northeast British Columbia, where PetroBakken owns significant mineral rights.

In 2009, the British Columbia government introduced the Infrastructure Royalty Credit program whereby Companies can receive a credit to royalties of up to 50% of costs incurred to construct roads, pipelines, and facilities. PetroBakken has applied and been approved to receive this credit to a maximum of $2.9 million. In August 2009, the Two Per Cent Royalty Relief Program was also introduced whereby wells spudded after August 31, 2009 and prior to July 1, 2010 are eligible for a 2% royalty credit.

STATEMENT OF RESERVES AND RESOURCES

Independent Reserve and Resource Evaluation Process

The reserves and resource data set forth herein is based upon evaluations completed by McDaniel as set forth in the McDaniel Report in respect of HBU reserves and resources and by Sproule in the Sproule Report in respect of PetroBakken reserves. Each of the McDaniel Report and the Sproule Report (collectively referred to herein as the "**Reports**") have effective dates of December 31, 2010. The reserves and resource data contained herein summarizes the oil, liquids, natural gas, shale gas and coalbed methane reserves of PetroBakken and the heavy oil and bitumen reserves and resources of the HBU, together with the net present values of future net revenue for those reserves and resources using forecast prices and costs, after provision for Alberta gas cost allowance. The reserves data contained herein is based on Sproule's and McDaniel's (collectively, the "**Evaluators**") respective price forecasts, in each case as of December 31, 2010.

In respect of the Heavy Oil Business Unit, McDaniel has historically estimated such reserves and resources using SAGD technology, as it is the presently recognized technology used to define in-situ oil sands reserves and resources. In 2009, McDaniel issued a transition report which conducted a rigorous analysis of our Conklin Pilot in conjunction with the reserve evaluation. This analysis encompassed all of the operational and observational data from the inception of the Conklin Pilot to clearly establish the effectiveness and sustainability of THAI® as an economic recovery process. The transition report concluded that the Conklin Pilot is successfully proving the THAI® process in a bitumen reservoir, and that the process is able to produce bitumen from a greater portion of the reservoir, specifically the thinner and less homogenous areas, than SAGD.

With respect to the Company's bitumen reserves and resources associated with the May River Property and the Conklin Pilot, McDaniel continues to estimate resources and reserves using SAGD extraction processes, as they have classified it as an immobile bitumen reservoir, and the information set forth herein in respect of such properties was evaluated on that basis. It is anticipated that McDaniel will evaluate and

assign reserves based upon the THAI® process at such time as commercial rates using THAI® are established.

At Kerrobert, Petrobank demonstrated improved on-stream times and production levels at our two well-pair project in 2010. As at December 31, 2010, production levels were at economic rates with consistent on-stream times, leading to McDaniel's first recognition of reserves based on the THAI® process. McDaniel has also recognized the incremental value of THAI®'s in-situ upgrading with sales oil revenues projected at approximately 10% higher than those for conventional heavy oil at Kerrobert.

The reserves and resource data set forth herein complies with the requirements of NI 51-101. Certain additional information not required by NI 51-101 has been included herein to provide readers with further information regarding our properties. All of the Company's reserves and resources are located in Canada.

In preparing the Reports, basic information was provided to the Evaluators by Petrobank and PetroBakken, which included land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluations and upon which the Reports are based, was obtained from public records, other operators and from the Evaluators non-confidential files. The extent and character of ownership and the accuracy of all factual data supplied for the Reports, from all sources, was accepted by the Evaluators as represented.

All evaluations and reviews of future net cash flow are stated prior to any provision for interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned and future site restoration and reclamation costs for wells in Canada to which reserves have been assigned. It should not be assumed that the estimated future net cash flow shown below is representative of the fair market value of the Company's properties. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, NGL, natural gas and bitumen reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, NGL, natural gas and bitumen reserves may be greater than or less than the estimates provided herein.

With respect to contingent resources, net present values were calculated based on the Company's share of future net revenue, before the deduction of income tax assuming SAGD development. The calculation considers such items as revenues, royalties, operating costs, abandonment costs and capital expenditures. Royalties have been calculated based on Alberta's royalty framework applicable to oil sands projects in Alberta. The calculation does not consider financing costs and general and administrative costs. All NPVs are calculated assuming natural gas is used as a fuel for steam generation. Revenues and expenditures were calculated based on McDaniel's forecast prices and costs as of January 1, 2011.

Notes on Reserves Data

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

The reserve information provided herein in respect of the Heavy Oil Business Unit does not include the Glover Property, the Dawson Property, the Sutton Creek Property or the Plover area lands as reserves have not been assigned to these properties.

Crude oil, natural gas liquids and natural gas reserves estimates presented in the Evaluators' reports are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is 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.

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

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.

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.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is only a 10 percent probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible 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, probable and possible) may be divided into developed and undeveloped categories:

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.

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.

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.

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

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves; and
- at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible 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 reserve estimates and the effect of aggregation is provided in the COGE Handbook.

Estimated future abandonment and reclamation costs related to a property have been taken into account by the Evaluators 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. Columns contained in this Annual Information Form may not add due to rounding.

Disclosure of Reserves Data

SUMMARY OF OIL AND GAS RESERVES
FORECAST PRICES AND COSTS
AS OF DECEMBER 31, 2010

	RESERVES													
	LIGHT AND MEDIUM OIL		HEAVY OIL		SOLUTION PLUS ASSOCIATED & NON-ASSOCIATED GAS		SHALE GAS		COALBED METHANE		NATURAL GAS LIQUIDS		BITUMEN	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PetroBakken (Canada) [(1)]														
Proved														
Developed Producing	50,719	45,234	169	145	62,992	55,976	565	413	233	239	3,807	3,096	-	-
Developed Non-Producing	4,556	3,955	39	38	6,422	5,414	-	-	-	-	309	254	-	-
Undeveloped	25,268	22,466	115	78	23,674	20,713	-	-	451	370	1,298	1,108	-	-
Total Proved	80,543	71,654	323	261	93,088	82,103	565	413	684	609	5,414	4,458	-	-
Probable	55,162	48,282	125	106	53,718	47,549	489	358	210	191	3,456	2,860	-	-
Total Proved Plus Probable	135,706	119,937	448	367	146,806	129,652	1,055	771	893	800	8,871	7,318	-	-
Heavy Oil Business Unit (Canada)														
Proved														
Developed Producing	-	-	575	474	-	-	-	-	-	-	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	-	-	2,457	2,245	-	-	-	-	-	-	-	-	-	-
Total Proved	-	-	3,032	2,719	-	-	-	-	-	-	-	-	-	-
Probable	-	-	1,806	1,536	-	-	-	-	-	-	-	-	90,572	70,764
Total Proved Plus Probable	-	-	4,837	4,255	-	-	-	-	-	-	-	-	90,572	70,764
Petrobank Total (Canada) [(1)]														
Proved														
Developed Producing	50,719	45,234	744	619	62,992	55,976	565	413	233	239	3,807	3,096	-	-
Developed Non-Producing	4,556	3,955	39	38	6,422	5,414	-	-	-	-	309	254	-	-
Undeveloped	25,268	22,466	2,572	2,323	23,674	20,713	-	-	451	370	1,298	1,108	-	-
Total Proved	80,543	71,654	3,355	2,980	93,088	82,103	565	413	684	609	5,414	4,458	-	-
Probable	55,162	48,282	1,931	1,642	53,718	47,549	489	358	210	191	3,456	2,860	90,572	70,764
Total Proved Plus Probable	135,706	119,937	5,285	4,622	146,806	129,652	1,055	771	893	800	8,871	7,318	90,572	70,764

Notes:

[(1)] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. PetroBakken holds all of the conventional assets in Canada. For further discussion see *"Statement of Reserves and Resources - Ownership of PetroBakken Minority Shareholders in PetroBakken Reserves"* .

* Table may not add due to rounding.

FORECAST PRICES AND COST
NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2010

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)					AFTER INCOME TAXES DISCOUNTED AT (%/year)					FUTURE NET VALUE
RESERVES CATEGORY	0 (CDN M$)	5 (CDN M$)	10 (CDN M$)	15 (CDN M$)	20 (CDN M$)	0 (CDN M$)	5 (CDN M$)	10 (CDN M$)	15 (CDN M$)	20 (CDN M$)	10%/year ($/boe)
PetroBakken (Canada) [(1)]											
Proved											
Developed Producing	3,355,327	2,574,088	2,134,978	1,849,317	1,646,490	3,043,625	2,355,232	1,965,725	1,711,000	1,529,335	36.87
Developed Non-Producing	278,446	218,660	181,759	156,590	138,214	202,497	157,663	129,913	110,961	97,122	35.30
Undeveloped	1,131,479	748,353	528,091	386,252	287,944	826,415	524,690	349,925	237,159	159,164	19.44
Total Proved	4,765,252	3,541,101	2,844,827	2,392,159	2,072,648	4,072,537	3,037,585	2,445,563	2,059,120	1,785,621	31.53
Probable	3,602,482	1,980,019	1,296,727	933,456	710,873	2,634,863	1,433,888	925,314	653,902	487,311	21.88
Total Proved Plus Probable	8,367,734	5,521,120	4,141,555	3,325,614	2,783,521	6,707,400	4,471,473	3,370,877	2,713,023	2,272,932	27.70
Heavy Oil Business Unit (Canada)											
Proved											
Developed Producing	3,021	2,336	1,850	1,500	1,242	3,021	2,336	1,850	1,500	1,242	3.90
Developed Non-Producing	-	-	-	-	-	-	-	-	-	-	-
Undeveloped	17,288	8,360	1,766	(3,161)	(6,880)	17,288	8,360	1,766	(3,161)	(6,880)	0.79
Total Proved	20,309	10,696	3,616	(1,661)	(5,638)	20,309	10,696	3,616	(1,661)	(5,638)	1.33
Probable	2,384,886	1,091,695	551,143	293,573	156,596	1,881,556	873,889	446,003	238,026	125,044	7.62
Total Proved Plus Probable	2,405,195	1,102,391	554,759	291,912	150,958	1,901,865	884,585	449,619	236,365	119,406	7.39
Petrobank Total [(1)]											
Proved											
Developed Producing	3,358,348	2,576,424	2,136,828	1,850,817	1,647,732	3,046,646	2,357,568	1,967,575	1,712,500	1,530,577	36.60
Developed Non-Producing	278,446	218,660	181,759	156,590	138,214	202,497	157,663	129,913	110,961	97,122	35.30
Undeveloped	1,148,767	756,713	529,857	383,091	281,064	843,703	533,050	351,691	233,998	152,284	18.02
Total Proved	4,785,561	3,551,797	2,848,444	2,390,498	2,067,010	4,092,846	3,048,281	2,449,179	2,057,459	1,779,983	30.65
Probable	5,987,368	3,071,714	1,847,870	1,227,029	867,469	4,516,419	2,307,777	1,371,317	891,928	612,355	14.05
Total Proved Plus Probable	10,772,929	6,623,511	4,696,314	3,617,527	2,934,479	8,609,265	5,356,058	3,820,496	2,949,387	2,392,338	20.92

Notes:

[(1)] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see *"Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves"* .

* Table may not add due to rounding.

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

RESERVES CATEGORY	REVENUE (CDN M$)	ROYALTIES (CDN M$)	OPERATING COSTS (CDN M$)	DEVELOPMENT COSTS (CDN M$)	WELL ABANDONMENT COSTS (CDN M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (CDN M$)	INCOME TAXES (CDN M$)	FUTURE NET REVENUE AFTER INCOME TAXES (CDN M$)
PetroBakken (Canada)[(1)]								
Total Proved	8,895,036	1,126,058	2,103,458	811,921	88,347	4,765,252	692,714	4,072,538
Total Proved Plus Probable	15,600,010	2,028,287	3,797,918	1,295,388	110,683	8,367,734	1,660,334	6,707,400
Heavy Oil Business Unit (Canada)								
Total Proved	207,049	21,467	106,312	57,454	1,507	20,309	-	20,309
Total Proved Plus Probable	7,285,538	1,583,232	2,453,189	831,931	11,991	2,405,194	503,330	1,901,864
Petrobank Total[(1)]								
Total Proved	9,102,085	1,147,525	2,209,770	869,375	89,854	4,785,561	692,714	4,092,847
Total Proved Plus Probable	22,885,548	3,611,519	6,251,107	2,127,319	122,674	10,772,928	2,163,664	8,609,264

Notes:

(1) All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see "Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves".

* Table may not add due to rounding.

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

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (Discounted at 10%/year) (CDN M$)	FUTURE NET REVENUE UNIT VALUE BEFORE INCOME TAXES (Discounted at 10%/year) (CDN$/boe of net reserves)
PetroBakken (Canada) [1]			
Total Proved	Light and Medium Crude Oil [2]	2,759,439	33.87
	Heavy Oil	7,223	24.59
	Coalbed Methane	499	4.91
	Shale Gas	1,273	18.50
	Natural Gas [3]	91,776	11.07
Total Proved Plus Probable	Light and Medium Crude Oil [2]	4,020,783	29.49
	Heavy Oil	9,399	22.55
	Coalbed Methane	814	6.10
	Shale Gas	2,170	16.89
	Natural Gas [3]	123,897	9.93
Heavy Oil Business Unit (Canada)			
Total Proved	Heavy Oil	3,616	1.33
Total Proved Plus Probable	Heavy Oil	38,979	9.16
	Bitumen	515,779	7.29
Petrobank Total (Canada) [1]			
Total Proved	Light and Medium Crude Oil [2]	2,759,439	33.87
	Heavy Oil	10,839	3.64
	Coalbed Methane	499	4.91
	Shale Gas	1,273	18.50
	Natural Gas [3]	91,776	11.07
Total Proved Plus Probable	Light and Medium Crude Oil [2]	4,020,783	29.49
	Heavy Oil	48,378	10.47
	Coalbed Methane	814	6.10
	Shale Gas	2,170	16.89
	Natural Gas [3]	123,897	9.93
	Bitumen	515,779	7.29

Notes:

[1] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see "*Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves*".

[2] Includes associated solution gas and by-products.

[3] Includes associated by-products.

* Table may not add due to rounding.

RECONCILIATION OF COMPANY RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Solution plus Associated & Non-Associated																		
	Light and Medium Oil			Heavy Oil			Gas			Shale Gas			Coal Bed Methane			Natural Gas Liquids			Bitumen
FACTORS	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Proved (Mboe)	Gross Probable (Mboe)	Gross Proved Plus Probable (Mboe)	Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)
PetroBakken (Canada) [1]																			
December 31, 2009	**71,324**	**44,339**	**115,664**	**305**	**117**	**421**	**14,205**	**7,344**	**21,549**	**222**	**75**	**297**	**290**	**371**	**661**	**3,125**	**1,922**	**5,047**	**-**
Extensions	13,269	11,924	25,193	-	-	-	1,580	1,446	3,026	-	-	-	-	-	-	776	655	1,431	-
Infill Drilling	4,012	2,878	6,890	-	-	-	420	342	762	-	-	-	-	-	-	213	133	346	
Technical Revisions	1,377	(5,246)	(3,869)	(27)	(25)	(52)	21	(257)	(235)	(56)	13	(43)	(6)	(4)	(10)	950	416	1,366	-
Acquisitions	6,357	4,338	10,695	98	34	132	5,506	2,559	8,065	-	-	-	121	35	156	1,526	662	2,187	-
Dispositions	(3,892)	(3,066)	(6,957)	-	-	-	(3,647)	(2,394)	(6,042)	-	-	-	(276)	(367)	(644)	(449)	(327)	(776)	-
Economic Factors	(13)	(5)	(18)	-	(1)	(1)	(272)	(85)	(358)	(16)	(7)	(23)	-	-	-	(8)	(4)	(12)	-
Production	(11,892)	-	(11,892)	(52)	-	(52)	(2,298)	-	(2,298)	(55)	-	(55)	(14)	-	(14)	(719)	-	(719)	-
December 31, 2010	**80,543**	**55,162**	**135,705**	**323**	**125**	**448**	**15,515**	**8,953**	**24,468**	**94**	**82**	**176**	**114**	**35**	**149**	**5,414**	**3,456**	**8,871**	**-**
Heavy Oil Business Unit (Canada)																			
December 31, 2009	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**70,013**
Extensions	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	20,559
Improved Recovery	-	-	-	3,032	1,806	4,837	-	-	-	-	-	-	-	-	-	-	-	-	-
December 31, 2010	**-**	**-**	**-**	**3,032**	**1,806**	**4,837**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**90,572**
Petrobank Total (Canada) [1]																			
December 31, 2009 [2]	**71,324**	**44,339**	**115,664**	**305**	**117**	**421**	**14,205**	**7,344**	**21,549**	**222**	**75**	**297**	**290**	**371**	**661**	**3,125**	**1,922**	**5,047**	**70,013**
Extensions	13,269	11,924	25,193	-	-	-	1,580	1,446	3,026	-	-	-	-	-	-	776	655	1,431	20,559
Infill Drilling	4,012	2,878	6,890	-	-	-	420	342	762	-	-	-	-	-	-	213	133	346	-
Improved Recovery	-	-	-	3,032	1,806	4,837	-	-	-	-	-	-	-	-	-	-	-	-	-
Technical Revisions	1,377	(5,246)	(3,869)	(27)	(25)	(52)	21	(257)	(235)	(56)	13	(43)	(6)	(4)	(10)	950	416	1,366	-
Acquisitions	6,357	4,338	10,695	98	34	132	5,506	2,559	8,065	-	-	-	121	35	156	1,526	662	2,187	-
Dispositions	(3,892)	(3,066)	(6,957)	-	-	-	(3,647)	(2,394)	(6,042)	-	-	-	(276)	(367)	(644)	(449)	(327)	(776)	-
Economic Factors	(13)	(5)	(18)	-	(1)	(1)	(272)	(85)	(358)	(16)	(7)	(23)	-	-	-	(8)	(4)	(12)	-
Production	(11,892)	-	(11,892)	(52)	-	(52)	(2,298)	-	(2,298)	(55)	-	(55)	(14)	-	(14)	(719)	-	(719)	-
December 31, 2010	**80,543**	**55,162**	**135,705**	**3,355**	**1,931**	**5,285**	**15,515**	**8,953**	**24,468**	**94**	**82**	**176**	**114**	**35**	**149**	**5,414**	**3,456**	**8,871**	**90,572**

Notes:

[1] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see "Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves".

[2] Petrominerales reserves have been excluded from the reconciliation of Company net reserves as this business unit was spun-off to Petrobank shareholders as of December 31, 2010.

* Table may not add due to rounding.

SUMMARY OF PRICING ASSUMPTIONS
AS OF DECEMBER 31, 2010
FORECAST PRICES AND COSTS

Evaluator	Year	West Texas Intermediate Crude Oil at Cushing Oklahoma $US/bbl	Inflation Rates %/Year	Exchange Rate $US/$Cdn	Light, Sweet Crude Oil 40° API at Edmonton $Cdn/bbl	Medium Crude Oil 29.3° API at Cromer $Cdn/bbl	Natural Gas AECO Gas Price $Cdn/MMbtu	Alberta Natural Gas Liquids: Edmonton Butane $Cdn/bbl	Alberta Natural Gas Liquids: Edmonton Pentanes Plus $Cdn/bbl
Sproule	2011	88.40	1.5	0.93	93.08	85.63	4.04	62.44	95.32
	2012	89.14	1.5	0.93	93.85	86.34	4.66	62.95	96.11
	2013	88.77	1.5	0.93	93.43	85.02	4.99	62.67	95.68
	2014	88.88	1.5	0.93	93.54	84.18	6.58	62.75	95.79
	2015	90.22	1.5	0.93	94.95	85.45	6.69	63.69	97.24
	Thereafter	Escalation rates of 1.5%							

Evaluator	Year	West Texas Intermediate Crude Oil at Cushing Oklahoma $US/bbl	Inflation Rates %/Year	Exchange Rate $US/$Cdn	Edmonton MSW $Cdn/bbl	WCS at Hardisty $Cdn/bbl	Alberta Bow River Hvy at Hardisty $Cdn/bbl	LLB at Hardisty $Cdn/bbl	Edmonton C5+ $Cdn/bbl	Diluent at Edmonton $Cdn/bbl	Edmonton SCO $Cdn/bbl	Edmonton Premium SCO $Cdn/bbl	Natural Gas at AECO - C $Cdn/MMbtu	Gas at Fieldgate $Cdn/MMbtu	Alberta Power $Cdn/MWH
McDaniel	2011	85.00	2.0	0.98	84.20	71.10	72.80	70.70	88.20	93.20	85.70	86.40	4.25	4.05	57.63
	2012	87.70	2.0	0.98	88.40	73.20	75.00	72.70	90.40	95.50	89.40	90.11	4.90	4.70	63.05
	2013	90.50	2.0	0.98	91.80	73.30	75.10	72.80	93.90	99.10	92.82	93.55	5.40	5.20	67.35
	2014	93.40	2.0	0.98	94.80	75.60	77.50	75.10	96.90	102.21	95.84	96.58	5.90	5.70	71.67
	2015	96.30	2.0	0.98	97.70	78.00	80.00	77.50	99.90	105.31	98.76	99.52	6.35	6.15	75.62
	2016	99.40	2.0	0.98	100.90	80.05	82.50	80.00	103.10	108.62	101.98	102.76	6.75	6.55	79.21
	Thereafter	+2% per year	2.0	0.98	Various escalation rates										

		Kerrobert					**May River**				
		Thai® OIL Kerrobert Delivery			Native Oil Kerrobert Delivery		Hardisty Delivery			Edmonton Delivery	
Evaluator	Year	Diluent at Fieldgate $Cdn/bbl	Dilbit at Hardisty $Cdn/bbl	Netback Oil Fieldgate $Cdn/bbl	Dilbit at Hardisty $Cdn/bbl	Netback Oil at Fieldgate $Cdn/bbl	Diluent at Fieldgate $Cdn/bbl	Dilbit at Hardisty $Cdn/bbl	Netback Bitumen at Fieldgate $Cdn/bbl	Dilbit at Edmonton $Cdn/bbl	Netback Bitumen at Fieldgate $Cdn/bbl
McDaniel	2011	94.20	71.10	62.69	71.10	57.62	96.20	71.10	56.41	70.50	55.49
	2012	96.52	73.20	64.66	73.20	59.53	98.56	73.20	58.32	72.60	57.39
	2013	100.14	73.30	64.09	73.30	58.29	102.22	73.30	56.82	72.70	55.89
	2014	103.27	75.60	66.19	75.60	60.19	105.39	75.60	58.66	75.00	57.73
	2015	106.39	78.00	68.34	78.00	62.22	108.56	78.00	60.65	77.40	59.72
	2016	109.72	80.50	70.61	80.50	64.31	111.93	80.50	62.69	79.90	61.76
	Thereafter	Various escalation rates									

Note:
Weighted average historical prices realized by PetroBakken for the year ended December 31, 2010 in Canada, were $4.27/Mcf for natural gas and $72.66/bbl for crude oil and NGL. Heavy Oil Business Unit historical prices are not presented herein as production volumes from operations are considered to be in the pre-operating stage and accordingly are capitalized. Forecast prices with respect to PetroBakken were provided by Sproule and prices with respect to the Heavy Oil Business Unit were provided by McDaniel.

Ownership of PetroBakken – Interests of Minority Shareholders in PetroBakken Reserves

As at December 31, 2010, the Company held a 59% interest in PetroBakken. As at December 31, 2010, the Sproule Report estimated PetroBakken's share of proved and probable reserves, representing 100% of the working interest of PetroBakken, which were consolidated in the Company's accounts. Minority shareholders indirectly owned 41% of these reserves at December 31, 2010.

The table below represents a summary of reserves indirectly owned by PetroBakken's minority shareholders and a summary of the net present value (before tax) of such reserves, all as at December 31, 2010. All reserves stated herein are based on forecast prices and costs.

MINORITY SHAREHOLDERS' INTERESTS IN PETROBAKKEN RESERVES AND NET PRESENT VALUE AS OF DECEMBER 31, 2010

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS [(1)]		NATURAL GAS LIQUIDS		TOTAL		NET PRESENT VALUE 10% BEFORE TAX ($M)
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)	
PetroBakken (Canada)											
Proved											
Developed Producing	20,795	18,546	69	59	26,154	23,217	1,561	1,269	26,784	23,744	875,341
Developed Non-Producing	1,868	1,622	16	16	2,633	2,220	127	104	2,449	2,111	74,521
Undeveloped	10,360	9,211	47	32	9,891	8,644	532	454	12,588	11,138	216,517
Total Proved	33,023	29,378	132	107	38,678	34,081	2,220	1,828	41,821	36,994	1,166,379
Probable	22,616	19,796	51	43	22,311	19,720	1,417	1,173	27,803	24,298	531,658
Total Proved Plus Probable	55,639	49,174	184	150	60,989	53,801	3,637	3,000	69,624	61,292	1,698,038

(1) Includes solution gas, associated and non-associated gas, and immaterial quantities of coalbed methane and shale gas.
* Table may not add due to rounding.

Undeveloped Reserves

Petrobank attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information and the optimization of existing fields.

Subject to the success of operations, within the next two years, the Company has the following plans regarding the development of proved and probable undeveloped reserves:

Heavy Oil Business Unit

There are proved and probable undeveloped reserves associated with the Kerrobert heavy oil project. We plan to develop these reserves throughout 2011 using THAI® technology. There are also probable undeveloped reserves associated with the Conklin Pilot area, which are based on SAGD technology. The undeveloped reserves associated with the Conklin Pilot area are not expected to be developed within the next two years as we are focusing on the development of other portions of the May River Property with our planned May River THAI® project.

PetroBakken Energy Ltd.

PetroBakken attributes proved and probable undeveloped reserves based on accepted engineering and geological practices as defined under NI 51-101. These practices include the determination of reserves based on the presence of commercial test rates from either production tests or drill stem tests, extensions of known accumulations based upon either geological or geophysical information, and the optimization of existing fields.

Subject to the success of operations, within the next two years, PetroBakken has the following plans regarding the development of proved and probable undeveloped reserves:

1. Proved undeveloped reserves in the Bakken oil pools were assigned on the basis of the regional nature of the producing formations. Performance expectations are based on offset well production. Bakken well locations typically were assigned where economic production has been demonstrated by wells in offsetting spacing units. The Sproule Report has assigned proved undeveloped reserves to 151.2 net light oil well locations in the Bakken properties in southeast Saskatchewan. In addition, the Sproule Report has assigned proved undeveloped reserves to 72.5 net light oil locations in the Conventional properties located in southeast Saskatchewan and Manitoba and to 88.5 net light oil locations in the Cardium properties located in Alberta. For the PetroBakken total proved undeveloped program, 45% of the capital is forecast to be spent in 2011 and over 96% of the forecasted capital scheduled to be spent by the end of 2013.

2. Probable undeveloped reserves in the Bakken properties are generally assigned adjacent to proved well locations. The Bakken in southeast Saskatchewan produces light oil plus solution gas and associated liquids based on typical gas/oil ratios and typical condensate yields where the gas is gathered. The Sproule Report has assigned probable undeveloped reserves to 109.2 net locations in the Bakken properties in southeast Saskatchewan. In addition, the Sproule Report has assigned probable undeveloped reserves to 32.4 net light oil locations in the conventional Mississippian properties located in southeast Saskatchewan and Manitoba and to 49.2 net light oil locations in the Cardium properties located in Alberta. For the PetroBakken total probable undeveloped program, 43% of the capital is forecast to be spent in 2011 and over 95% of the forecasted capital is scheduled to be spent by the end of 2013. Drilling plans are affected by economic considerations including commodity price.

PetroBakken's drilling plan for 2011 is expected to range from 190 to 210 net wells in aggregate depending on commodity prices. Wells are expected to be drilled in central Alberta on our Cardium property and southeast Saskatchewan, on both the Bakken and conventional Mississippian properties.

Undeveloped reserves, like all projects, are subject to competition for capital and consequently may be delayed or accelerated from time to time.

UNDEVELOPED RESERVES
FORECAST PRICES AND COSTS

The following table sets out the volume of the Company's proved undeveloped and probable undeveloped reserves over the most recent three financial years and the amount of reserves first attributed in each of those years.

	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS [1]		NATURAL GAS LIQUIDS		BITUMEN	
	Gross (Mbbl)		Gross (Mbbl)		Gross (MMcf)		Gross (Mbbl)		Gross (Mbbl)	
RESERVES CATEGORY	First Attributed	Booked	First Attributed	Booked	First Attributed	Booked	First Attributed	Booked	First Attributed	Booked
PetroBakken (Canada) [2]										
Proved Undeveloped										
Prior to 2008	-	7,873	-	-	-	45,852	-	496	-	-
Dec. 31, 2008	7,457	9,757	-	-	2,105	14,403	373	520	-	-
Dec. 31, 2009	2,589	21,575	-	115	240	25,444	41	727	-	-
Dec. 31, 2010	11,945	25,268	-	115	11,339	24,125	680	1,298		
Probable Undeveloped										
Prior to 2008	-	7,396	-	-	-	25,935	-	480	-	-
Dec. 31, 2008	4,861	7,334	-	-	1,696	6,735	235	380	-	-
Dec. 31, 2009	3,685	22,656	-	15	942	19,333	158	793	-	-
Dec. 31, 2010	13,983	29,149	-	15	13,415	24,504	792	1,457	-	-
Heavy Oil Business Unit (Canada)										
Proved Undeveloped										
Prior to 2008	-	-	-	-	-	-	-	-	-	-
Dec. 31, 2008	-	-	-	-	-	-	-	-	-	-
Dec. 31, 2009	-	-	-	-	-	-	-	-	-	-
Dec. 31, 2010	-	-	2,457	2,457	-	-	-	-	-	-
Probable Undeveloped										
Prior to 2008	-	-	-	-	-	-	-	-	-	50,766
Dec. 31, 2008	-	-	-	-	-	-	-	-	43,506	68,982
Dec. 31, 2009	-	-	-	-	-	-	-	-	1,031	70,013
Dec. 31, 2010	-	-	1,439	1,439	-	-	-	-	20,559	90,572
Petrobank Total (Canada) [2]										
Proved Undeveloped										
Prior to 2008	-	7,873	-	-	-	45,852	-	496	-	-
Dec. 31, 2008	7,457	9,757	-	-	2,105	14,403	373	520	-	-
Dec. 31, 2009	2,589	21,575	-	115	240	25,444	41	727	-	-
Dec. 31, 2010	11,945	25,268	2,457	2,572	11,339	24,125	680	1,298	-	-
Probable Undeveloped										
Prior to 2008	-	7,396	-	-	-	25,935	-	480	-	50,766
Dec. 31, 2008	4,861	7,334	-	-	1,696	6,735	235	380	43,506	68,982
Dec. 31, 2009	3,685	22,656	-	15	942	19,333	158	793	1,031	70,013
Dec. 31, 2010	13,983	29,149	1,439	1,454	13,415	24,504	792	1,457	20,559	90,572

Notes:
[1] Includes solution gas, associated and non-associated gas, and immaterial quantities of coalbed methane and shale gas.
[2] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see "*Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves*".
* Table may not add due to rounding.

Significant Factors or Uncertainties Affecting Reserves Data

There are numerous uncertainties inherent in estimating quantities of proved reserves, including many factors beyond the control of the Company. The reserve data included herein represents 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, pricing, surface access issues, availability of services, technical issues affecting well performance, the assumed effects of regulation by governmental agencies, future royalty and tax regimes and future capital and operating costs, all of which may vary considerably from actual results. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. 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 expected therefrom, prepared

by different engineers or by the same engineers at different times, may vary substantially. The actual production, revenues, taxes and development and operating expenditures of the Company with respect to these reserves will vary from such estimates, and such variances could be material.

Estimates with respect to 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. 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 will result in variations, which may be substantial, in the estimated reserves.

Consistent with the securities disclosure legislation and policies of Canada, the Company has used forecast prices and costs in calculating reserve quantities included herein. Actual future net cash flows also 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.

FUTURE DEVELOPMENT COSTS [1] [2]

		FORECAST PRICES AND COSTS	
	YEAR	Total Proved Reserves	Total Proved Plus Probable Reserves
PetroBakken (Canada) [3]		(CDN M$)	(CDN M$)
	2011	387,901	596,600
	2012	226,030	360,100
	2013	162,713	283,000
	2014	26,558	43,400
	2015	1,150	1,600
Thereafter		7,568	10,700
Total undiscounted		811,921	1,295,400
Total discounted at 10%		721,440	1,146,800
Heavy Oil Business Unit (Canada)			
	2011	37,230	42,330
	2012	9,884	221,293
	2013	1,592	111,639
	2014	1,624	4,871
	2015	1,656	4,968
Thereafter		5,468	446,830
Total undiscounted		57,454	831,931
Total discounted at 10%		50,481	441,921
Petrobank Total (Canada) [3]			
	2011	425,131	638,930
	2012	235,914	581,393
	2013	164,305	394,639
	2014	28,182	48,271
	2015	2,806	6,568
Thereafter		13,036	457,530
Total undiscounted		869,375	2,127,331
Total discounted at 10%		771,921	1,588,721

Notes:

[1] The table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted.

[2] Future development costs are expected to be funded by internally generated cash flow, and from a combination of equity financing and debt, the costs of which are not expected to have an effect on the reserves or future net revenue.

[3] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see "*Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves*".

* Table may not add due to rounding.

Summary of HBU Reserves and Contingent Resources

The table below sets forth the Heavy Oil Business Unit's stand alone reserves and contingent resources and associated discounted future net revenues as of December 31, 2010, as evaluated in the McDaniel Report. The reserves set forth below are attributable to the Conklin Pilot area and Kerrobert Project. Contingent resources are attributable to the May River Property and do not include reserves attributed to the Conklin Pilot area or the Kerrobert Project.

The following tables summarize the McDaniel Report, as at December 31, 2010 and present the HBU's reserves and contingent resources, for summary purposes only. Further information in respect of reserves is set forth under the heading "*Disclosure of Reserves Data*" and "*Other Oil and Gas Information*".

For additional information relating to the Heavy Oil Business Unit's Contingent Resources, please see the disclosure under the headings "*Contingent Resource Categories*" and "*Heavy Oil Business Unit Overview*".

HEAVY OIL BUSINESS UNIT GROSS RESERVES / RESOURCES[(1)(2)]
AS OF DECEMBER 31, 2010

	Heavy Oil	Bitumen	Total
	(Mbbl)	(Mbbl)	(Mbbl)
Proved Developed Producing Reserves	575	-	575
Total Proved Reserves	3,032	-	3,032
Proved + Probable (2P) Reserves	4,837	90,572	95,409
Proved + Probable + Possible (3P) Reserves [(2)(3)]	8,513	101,512	110,025
Low Estimate Contingent Resources [(4)(5)]	-	473,964	473,964
Best Estimate Contingent Resources [(4)(5)]	-	560,131	560,131
High Estimate Contingent Resources [(4)(5)]	-	697,221	697,221

Notes:

1. Gross reserves and/or resources include the working interest reserves/resources before deductions of royalties payable to others.
2. Based on McDaniel bitumen and heavy oil netback prices.
3. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
4. Contingent resources, as evaluated by McDaniel, are those quantities of bitumen estimated to be potentially recoverable using SAGD technology from known accumulations but are classified as a resource rather than a reserve primarily due to the absence of regulatory approvals, detailed design estimates and near term development plans. There is no certainty that it will be economically viable to produce any portion of the resources. See "*Contingent Resource Categories*".
5. A low estimate means higher certainty (P90), a best estimate (P50) means most likely and a high estimate means lower certainty (P10). See "*Contingent Resource Categories*".

HEAVY OIL BUSINESS UNIT BEFORE TAX NET PRESENT VALUES [(1) (2) (3)]
AS OF DECEMBER 31, 2010

	$MILLIONS					
Net Present Value Discounted at:	**0%**	**5%**	**8%**	**10%**	**15%**	**20%**
Total Proved Reserves (1P)	20	11	6	4	(2)	(6)
Proved plus Probable Reserves (2P)	2,405	1,102	724	555	292	151
Proved plus Probable plus Possible Reserves (3P)	3,163	1,405	929	722	408	242
Low Estimate Contingent Resources	10,180	3,923	2,190	1,450	393	(82)
Best Estimate Contingent Resources	14,088	5,258	3,000	2,067	770	194
High Estimate Contingent Resources	20,413	6,821	3,794	2,615	1,053	384

Notes:
1. Based on McDaniel forecast bitumen and heavy oil netback prices.
2. Interest expenses and corporate overhead, etc. were not included.
3. The net present values do not represent the fair market value of the reserves and/or resources.

Contingent Resource Categories

"Resources" are oil and gas volumes that are estimated to have originally existed in the earth's crust as naturally occurring accumulations but are not capable of being classified as "reserves" as described below. The COGE Handbook defines "contingent resources" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status. Resources and contingent resources do not constitute, and should not be confused with, reserves.

The resources assigned to the May River Property have been classified as contingent and have been sub-classified as economic contingent resources deemed to be economically viable under reasonable fiscal conditions. In respect of the May River project, contingencies include: current uncertainties around the specific scope and timing of the development of the project; lack of regulatory approvals; uncertainty regarding marketing plans for production from the subject area; and need for improved estimation of project costs. Contingent resources do not constitute, and should not be confused with, reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent resources on the May River property.

Contingent resources have been determined for the following mutually exclusive categories:

- **Low Estimate**: This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P90 confidence level.
- **Best Estimate**: This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of the central tendency of the uncertainty distribution (most likely/mode, P50/median, or arithmetic average/mean).

- **High Estimate**: This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P10 confidence level.

McDaniel defines the best estimate of an exploitable in-situ interval as a subsurface stratigraphic interval containing a minimum thickness of 10 metres of continuous bitumen-saturated sand, net of localized permeability barriers, with porosity and mass bitumen content (ratio of bitumen to water and mineral matter) meeting a minimum of 27 and eight percent, respectively, with a competent top reservoir seal. By continuous bitumen-saturated sand, it is intended that nothing that impedes steam or solvent transmission to any significant degree, either vertically or laterally can be present within the interval. Mudstones, impermeable sandstones, paleosols, coals, etc. are not included in net pay values and must not be laterally traceable over approximately one-hundred metres outwards in all directions from a particular wellbore. This distance corresponds to the established lateral sweep of most in-situ SAGD recovery schemes. A competent top reservoir seal is defined by McDaniel's as a shale or mudstone, sequence of sand and shale or mudstone, coal or some combination thereof, that can be expected to act as a permeability barrier on either a local or regional scale through application of the defined or anticipated recovery scheme.

McDaniel defines the Low Estimate and High Estimate of an exploitable in-situ interval as meeting all of the Best Estimate requirements with the exception of meeting a minimum thickness of 12 and eight metres of net bitumen-saturated sand, respectively.

OTHER OIL AND GAS INFORMATION

2011 Production Estimates

The following table sets out the volume of the Company's production estimated for the year ended December 31, 2011 which is reflected in the estimate of future net revenue disclosed in the tables contained in this AIF. Heavy Oil Business Unit bitumen volumes in the McDaniel Report are not forecast to start production until 2013.

	LIGHT AND MEDIUM OIL	HEAVY OIL	NATURAL GAS [1]	NATURAL GAS LIQUIDS	OIL EQUIVALENT
RESERVES CATEGORY	Gross (bbl/d)	Gross (bbl/d)	Gross (Mcf/d)	Gross (bbl/d)	Gross (boe/d)
PetroBakken (Canada) [2]					
Total Proved Producing	25,106	112	30,355	2,067	32,345
Total Proved	33,994	131	34,492	2,481	42,355
Total Proved Plus Probable	39,701	138	38,220	2,793	49,002
Petrobank (Canada)					
Total Proved Producing	-	175	-	-	175
Total Proved	-	620	-	-	620
Total Proved Plus Probable	-	719	-	-	719
Petrobank Total (Canada) [2]					
Proved Producing	25,106	287	30,355	2,067	32,520
Total Proved	33,994	751	34,492	2,481	42,975
Total Proved Plus Probable	39,701	857	38,220	2,793	49,721

Notes:

[1] Includes solution gas, associated and non-associated gas, and immaterial quantities of coalbed methane and shale gas.

[2] All reserves presented herein represent the Company's and the Company's subsidiaries interest, where applicable. The reserves of the Company's subsidiaries have been consolidated into the Company's accounts. Note that as at December 31, 2010, the Company held a 59% interest in PetroBakken. For further discussion see "*Statement of Reserves and Resources - Ownership of PetroBakken - Interests of Minority Shareholders in PetroBakken Reserves*".

* Table may not add due to rounding.

Oil and Gas Wells

The following table summarizes Petrobank's interests, by region and on a consolidated basis, as at December 31, 2010, in oil and natural gas wells which are producing or which are considered capable of production. All non-producing wells considered capable of production have been standing for a period of less than one year, are within economic distance of transportation facilities and are classified as proved developed non-producing reserves in the Sproule Report. All of the Company's properties are located onshore.

	Producing				**Non-Producing**			
	Oil		Natural Gas		Oil		Natural Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Saskatchewan	2,708	1,460	5	3	1,320	737	121	7
Alberta	335	249	524	387	127	96	154	117
British Columbia	-	-	34	25	3	3	32	26
Manitoba	19	18	-	-	5	5	1	1
PetroBakken[(1)]	3,062	1,727	563	415	1,455	841	308	151
Alberta	3	3	-	-	-	-	-	-
Saskatchewan	2	2	-	-	-	-	-	-
HBU	5	5	-	-	-	-	-	-
Total Company	3,067	1,732	563	415	1,455	841	308	151

Notes:
1. Includes 100% of the wells owned by PetroBakken. Petrobank owns 59% of the outstanding shares of PetroBakken.

Land Holdings - Consolidated

The land holdings of the Company, including those that are undeveloped, by region and on a consolidated basis, as at December 31, 2010, are set forth in the following table (in 000s of acres unless otherwise noted).

	Developed		**Undeveloped**		**Total**		**Avg.**
Area	Gross	Net	Gross	Net	Gross	Net	**WI%**
Saskatchewan	275.4	172.3	742.2	612.1	1,017.6	784.4	77
Alberta	365.5	229.3	557.8	404.4	923.3	633.7	69
British Columbia	68.8	41.6	110.9	85.9	179.7	127.5	71
Manitoba	4.5	2.4	52.1	48.0	56.6	50.4	89
Northwest Territories	-	-	6.4	2.2	6.4	2.2	34
United States - Montana	-	-	103.6	51.8	103.6	51.8	50
PetroBakken[(1)]	714.2	445.6	1,573.0	1,204.4	2,287.2	1,650.0	72
Saskatchewan	0.1	0.1	27.5	27.5	27.6	27.6	100
Alberta	0.5	0.5	66.4	66.4	66.9	66.9	100
Heavy Oil Business Unit	0.6	0.6	93.9	93.9	94.5	94.5	100
Total Company	**714.8**	**446.2**	**1,666.9**	**1,298.3**	**2,381.7**	**1,744.5**	**73**

Notes:
1. Includes 100% of the lands owned by PetroBakken. Petrobank owns 59% of the outstanding shares of PetroBakken.

Provincial governments in Canada grant rights to explore for and produce oil and natural gas under leases, licenses and permits, which may be continued, indefinitely by producing under the lease. Accordingly, to preserve this acreage the Company is committed to bring wells on production.

PetroBakken estimates that rights to explore, develop and exploit 233,782 net acres of its undeveloped land in Canada are scheduled to expire by December 31, 2011. PetroBakken will attempt to extend some of this expiring acreage through any continuation provisions it is afforded under the individual title documents and applicable governmental regulations. The Heavy Oil Business Unit does not anticipate any of our lands will expire in 2011.

Forward Contracts and Future Commitments

See Note 13, "*Financial Instruments and Financial Risk Management*", and Note 16, "*Commitments and Contingencies*", to the Company's December 31, 2010 consolidated financial statements, which information is incorporated herein by reference and can be found on SEDAR at www.sedar.com.

Additional Information Concerning Abandonment and Reclamation Costs

Abandonment and reclamation costs were estimated for all legal obligations associated with the retirement of long-lived tangible assets such as wells, facilities and plants based on market prices or on the best information available where no market price was available. For obligations in Canada, the estimated costs are then inflated at two percent over time until the actual retirement is expected to occur.

As at December 31, 2010, the Company expected to incur abandonment and reclamation costs in respect of 3,167 net oil and gas wells in Canada (PetroBakken – 3,134 net wells; Heavy Oil Business Unit – 33 net wells).

The total abandonment and reclamation costs net of salvage values of all the Company's operations, on a consolidated basis, are estimated to be $177.2 million (PetroBakken - $162.8 million; Heavy Oil Business Unit - $14.4 million) on an undiscounted basis and $25.9 million (PetroBakken - $22.3 million; Heavy Oil Business Unit - $3.6 million) discounted at 10 percent. In the next three financial years the Company anticipates that approximately $7.6 million (PetroBakken - $7.5 million; Heavy Oil Business Unit - $0.1 million) on an undiscounted basis and $4.6 million (PetroBakken - $4.5 million; Heavy Oil Business Unit - $0.1 million) discounted at 10 percent will be incurred on abandonment and reclamation costs.

The calculation of future net revenue in the future prices and costs tables contained herein have excluded $22.6 million (PetroBakken - $9.7 million; Heavy Oil Business Unit - $12.9 million) on an undiscounted basis and $3.7 million (PetroBakken - $0.6 million; Heavy Oil Business Unit - $3.1 million) discounted at 10 percent from the Company's estimates, as these calculations do not reflect any costs for abandonment and reclamation for facilities and wells for which no proved reserves have been attributed.

Tax Horizon

PetroBakken will utilize its approximate $2.2 billion Canadian tax pool balance at December 31, 2010 to shelter it from paying current cash income taxes. Based on the Sproule Report, and PetroBakken's exploration and development plans, PetroBakken does not expect to pay income tax in Canada until 2013 or later.

In Canada, Petrobank's tax pools shelter it from paying current cash income taxes. Based on the McDaniel Report and the Company's current exploration and development plans, Petrobank does not expect to pay income tax in Canada until 2017 or later.

Capital Expenditures

The following table summarizes capital expenditures related to the Company's activities for the year ended December 31, 2010. Capital expenditures from continuing operations, which includes PetroBakken and HBU, have been disclosed separately from Petrominerales, which was spun-off to Petrobank shareholders on December 31, 2010.

(000s)	PetroBakken	HBU	Total from Continuing Operations[1]	Petrominerales
Drilling and completions	568,905	24,644	593,549	248,615
Facilities	91,245	28,243	119,488	211,147
Land	94,751	504	95,255	-
Seismic	6,359	6,028	12,387	45,485
Pilot capital[2]	-	31,148	31,148	-
Asset acquisition	30,348	18,057	48,405	-
Other[3]	20,263	12,868	33,131	14,636
Total capital expenditures	**811,871**	**121,492**	**933,363**	**519,883**

Notes:

1. Petrominerales has been presented as discontinued operations for the year ended December 31, 2010 as this business unit was spun-off to Petrobank shareholders on December 31, 2010.
2. Pilot capital includes: well workovers and operating costs, net of revenues received.
3. Includes health, safety and environmental, capitalized salaries and office furniture and fixtures. HBU also includes $3.0 million of capitalized cash interest.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs incurred for the year ended December 31, 2010.

(000s)	Acquisition Costs[1]			
	Proved	**Unproved[2]**	**Exploration**	**Development**
PetroBakken	331,954	477,102	30,458	636,051
Heavy Oil Business Unit	-	18,561	10,808	92,123
Total from Continuing Operations[3]	331,954	495,663	41,266	728,174
Petrominerales	-	30,541	445,028	74,855

Notes:

1. Pursuant to NI 51-101, "proved properties" are all properties to which proved reserves have been specifically attributed and "unproved properties" are properties to which no reserves have been specifically attributed.
2. Includes $94.8 million of land acquisition costs incurred by PetroBakken in 2010, primarily for lands acquired in the Cardium and southeast Saskatchewan and $30.3 million of asset acquisition costs.
3. Petrominerales has been presented as discontinued operations for the year ended December 31, 2010 as this business unit was spun-off to Petrobank shareholders at December 31, 2010.

Exploration and Development Activities

The following table summarizes the gross and net exploratory and development wells in which the Company and its subsidiaries participated during the year ended December 31, 2010.

	Exploration		Development		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
PetroBakken (Canada)						
Oil	7.0	6.5	314.0	229.1	321.0	235.6
Natural Gas	1.0	1.0	3.0	2.7	4.0	3.7
Service Wells	-	-	-	-	-	-
Successful	8.0	7.5	314.0	228.8	322.0	236.3
Dry	-	-	3.0	3.0	3.0	3.0
Total PetroBakken	**8.0**	**7.5**	**317.0**	**231.8**	**325.0**	**239.3**
Success Rate	**100%**	**100%**	**99%**	**99%**	**99%**	**99%**
Heavy Oil Business Unit (Canada)						
Total Heavy Oil	**-**	**-**	**-**	**-**	**-**	**-**
Success Rate	**-**	**-**	**-**	**-**	**-**	**-**
Prominerales[(1)]						
Oil	21	21	25	17	46	38
Service Wells	-	-	-	-	-	-
Successful	17	17	25	17	42	34
Dry	4	4	-	-	4	4
Total Petrominerales	**21**	**21**	**25**	**17**	**46**	**38**
Success Rate	**81%**	**81%**	**100%**	**100%**	**91%**	**89%**

Note:

1. Petrominerales has been presented as discontinued operations for the year ended December 31, 2010 as this business unit was spun-off to Petrobank shareholders at December 31, 2010.

The Company and its subsidiaries' exploration and development plans are discussed under the heading "*Business of the Company*".

Production History

Production

The following table shows PetroBakken and Petrominerales average working interest production volumes before deduction of royalties payable to others and average netbacks received for each of the last four fiscal quarters by product type. Heavy Oil Business Unit volumes are excluded as Conklin and Kerrobert operations are considered to be in the pre-operating stage and accordingly all operating costs, net of revenue received, are capitalized.

	Three Months Ended				Year Ended
	Mar 31, 2010	**June 30, 2010**	**Sept 30, 2010**	**Dec 31, 2010**	**Dec 31, 2010**
Average daily production [(1) (2)]					
PetroBakken – light / medium oil (bbl/d)	37,654	34,852	33,230	34,754	35,109
PetroBakken – natural gas (Mcf/d)	32,662	44,469	41,193	39,474	39,473
Total PetroBakken (boepd)	43,098	42,263	40,095	41,333	41,688
Petrominerales – light / medium oil (bbl/d)	38,199	44,203	32,667	33,142	37,027

Notes:

1. NGLs have been included with light/medium oil as they are not considered to be material. NGLs represent approximately five percent of PetroBakken's total production.
2. Heavy oil has been included in light/medium oil as it is not considered material. Heavy oil represents less than one percent of PetroBakken's total production.

The following table sets forth PetroBakken's average daily production volumes, for each significant field and on a consolidated basis, for the twelve month period ended December 31, 2010.

	Light / Medium Oil and NGL (bbl)[1]	Natural Gas (Mcf)	Total (boe)
Bakken	24,472	6,711	25,591
Conventional (SE SK)	6,842	2,521	7,262
Cardium (Central AB)	2,463	12,761	4,590
NE BC/Other AB	1,332	17,480	4,245
Total PetroBakken	**35,109**	**39,473**	**41,688**

Note:

1. NGL's and heavy oil have been included with light/medium oil, as they are not considered to be material.

PetroBakken (Canada) Operating Netback by Product

Light/Medium Crude Oil and NGL Operating Netback [4] ($ per bbl)

	Three Months Ended				Year Ended
	Mar 31, 2010	June 30, 2010	Sept 30, 2010	Dec 31, 2010	Dec 31, 2010
Average price received [1]	76.08	70.98	68.43	75.19	72.66
Royalties	10.56	10.36	9.67	10.94	10.38
Operating costs [2]	7.95	7.89	8.88	9.56	8.58
Operating netback [3]	57.57	52.73	49.88	54.69	53.70

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.
4. Heavy oil has been included in light/medium oil and NGL as it is not considered to be material. Heavy oil represents less than one percent of PetroBakken's total production.

Natural Gas Operating Netback ($ per Mcf)

	Three Months Ended				Year Ended
	Mar 31, 2010	June 30, 2010	Sept 30, 2010	Dec 31, 2010	Dec 31, 2010
Average price received [1]	5.20	4.11	3.82	3.96	4.27
Royalties	0.60	0.60	0.62	0.66	0.62
Operating costs [2]	1.12	1.03	1.00	0.98	1.03
Operating netback [3]	3.48	2.48	2.20	2.32	2.62

Notes:

1. Net of transportation expenses.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as field staff salaries, power, fuel, chemicals, repairs and maintenance, property taxes, processing and treating fees, overhead fees and other costs.
3. Excludes hedging activities.

Prominerales (Colombia) Operating Netback

Light/Medium Crude Oil and NGL Operating Netback ($ per bbl)

	Three Months Ended				Year Ended
	Mar 31, 2010	**June 30, 2010**	**Sept 30, 2010**	**Dec 31, 2010**	**Dec 31, 2010**
Average price received [(1)]	67.17	65.15	67.08	74.93	68.80
Royalties	7.39	6.51	9.44	12.21	8.72
Operating costs [(2)]	6.71	6.61	7.90	13.20	8.45
Operating netback	53.07	52.03	49.74	49.52	51.63

Notes:
1. Net of transportation expenses and excludes revenue from purchased oil.
2. Operating costs are expenses incurred in the operation of producing properties and include items such as Ecopetrol operating fees, field staff salaries, repairs and maintenance, overhead fees and other costs.
3. Prominerales has been presented as discontinued operations for the year ended December 31, 2010 as this business unit was spun-off to the Petrobank shareholders effective December 31, 2010.

RISK FACTORS

Investing in securities of Petrobank involves inherent risks. The risks described below are not the only ones facing the Company. Additional risks not presently known to the Company or that the Company currently deems immaterial may also impair the Company's business operations. If any of the following risks actually occur, Petrobank's business, financial condition and operating results could be materially and adversely affected.

Risks Applicable to Petrobank and PetroBakken

An investment in Petrobank may be considered speculative due to the nature of Petrobank's and PetroBakken's involvement in the exploration for, and the acquisition, development, production and marketing of, oil and natural gas and its current stage of development. Oil and gas operations involve many risks, which even a combination of experience and knowledge, and careful evaluation may not be able to overcome. An investment in Petrobank is subject to all of the risks attributable to PetroBakken, as a substantial portion of the value of a Petrobank common share is attributable to Petrobank's ownership of PetroBakken. The following section sets forth risks applicable to the business, operations and results of the Company, both directly and as a result of its ownership of PetroBakken shares.

Commodity Price Volatility

Both oil and natural gas prices are unstable and are subject to fluctuation. Any material decline in prices could result in a reduction of Petrobank's net production revenue and overall value and could result in ceiling test write-downs. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of Petrobank's reserves. Petrobank might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in Petrobank's net production revenue causing a reduction in its oil and gas acquisition and development activities. A substantial material decline in prices from historical average prices could reduce PetroBakken's ability to refinance its outstanding subordinated notes and may result in a reduced borrowing base under credit facilities available to the Company and possibly require that a portion of the Company's bank debt be repaid.

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, known as hedging. 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. The Company could also be subject to margin requirements associated with certain hedging instruments.

Financial Resources and Indebtedness

The Company's cash from operations may not be sufficient to fund its ongoing activities and implement its business plans. From time to time the Company may enter into transactions to acquire assets or the shares of other companies. These transactions along with the Company's ongoing operations may be financed partially or wholly with debt, which may increase the Company's debt levels above industry standards. Our indebtedness could affect the market price of the common shares. The agreements governing our credit facility provide that if we are in default under the credit facility or fail to comply with certain covenants, we may be required to repay the indebtedness at an accelerated rate. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may receive a judgment and have an unsecured claim on the properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors.

Depending on future exploration and development plans, the Company may require additional financing, which may not be available or, if available, may not be available on favourable terms. Failure to obtain such financing on a timely basis could cause the Company to forfeit or forego various opportunities. Credit markets throughout the world may be restrictive, which could limit the Company's ability to access incremental debt.

Reserves

The Company's future reserves, production and resulting cash flows are highly dependent upon success in exploiting the Company's current reserves base and acquiring or discovering additional reserves. Without reserves additions through exploration, acquisition or development activities, Petrobank's reserves and production will decline over time. Exploring for, developing or acquiring reserves is capital intensive. To the extent cash flows from operations are insufficient to fund the Company's capital expenditures and external sources of capital become limited or unavailable, Petrobank's ability to make the necessary capital investments to maintain oil and natural gas reserves will be impaired. Costs to find and develop or acquire additional reserves also depend on success rates, which vary over time.

Strong Competition

The oil and natural gas industry is intensely competitive. Competition is particularly intense in the acquisition of prospective oil and natural gas properties and oil and gas reserves. Petrobank's competitive position depends on its geological, geophysical and engineering expertise, its financial resources, its ability to develop its properties and its ability to select, acquire and develop proved reserves. Petrobank competes with a substantial number of other companies having larger technical staffs and greater financial and operational resources. Such companies not only engage in the acquisition, exploration, development and production of oil and natural gas reserves, but also carry on refining operations and market refined products. Petrobank also competes with major and independent oil and natural gas companies and other industries supplying energy and fuel in the marketing and sale of oil and natural gas to transporters, distributors and end users, including industrial, commercial and individual consumers. In addition, Petrobank competes with other oil and natural gas companies in attempting to secure drilling rigs and other equipment necessary for drilling and completion of wells. Such equipment may be in short supply from time to time. Further, equipment and other materials necessary to construct production and transmission facilities may be in short supply from time to time. Finally, companies not previously

investing in oil and natural gas may choose to acquire reserves to establish a firm supply or simply as an investment, such companies will also provide competition for Petrobank.

Oil and Natural Gas Production Could Vary Significantly From Reported Reserves

The Company's reserve evaluations have been prepared in accordance with NI 51-101. There are numerous uncertainties inherent in estimating quantities of reserves and cash flows to be derived therefrom, including many factors that are beyond the control of the Company. The reserves information set forth in this Annual Information Form represent estimates only. The reserves from the Company's properties have been independently evaluated by McDaniel and Sproule in their respective reports. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs and royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Company. Actual production and cash flows derived therefrom will vary from these evaluations, and such variations could be material. These evaluations are based, in part, on the assumed success of exploitation activities intended to be undertaken in future years. The reserves and estimated cash flows to be derived therefrom contained in such evaluations will be reduced to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations.

Canadian GAAP requires that management apply certain accounting policies and make certain estimates and assumptions, which affect reported amounts in the consolidated financial statements of the Company. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trading price of the Company's shares.

Under Canadian GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a ceiling-test, which is based upon estimated future net cash flow from reserves. The carrying value is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying value. When the carrying value is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying value of assets exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

Upon transition to IFRS, impairment testing is to be performed at the cash generating unit level, which is lower than the current cost center level. In addition, IAS 36 uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of: value-in-use and fair value less costs to sell. Value in use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP, which uses undiscounted cash flows to test and measure impairment. This may result in more frequent write-downs in the carrying amounts of assets under IFRS because the asset carrying amounts previously supported under Canadian GAAP were based on undiscounted cash flows. However, under IAS 36, impairment losses that were previously

recognized may be reversed where circumstances change such that the impairment is reduced. This differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

Operating Costs and Production Levels

An increase in operating costs or a decline in our production level could have a material adverse effect on our results of operations and financial condition. Electricity, trucking, chemicals, supplies, reclamation and abandonment and labour costs are a few of the operating costs that are susceptible to material fluctuation. The level of production from our existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond our control. A significant decline in our production could result in materially lower revenues and cash flow.

Marketing of Oil and Natural Gas Production

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

Our business depends in part upon the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as United States federal and state, regulation of oil and gas production, processing and transportation, tax and energy policies, general economic conditions, weather, pipeline disruptions and changes in supply and demand could adversely affect our ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of our production, overall production or realized prices may decline, which could negatively affect the market price of our shares.

Exchange Rate Volatility

To the extent revenues and expenditures denominated in or strongly linked to the U.S. dollar are not equivalent, the Company is exposed to exchange rate risk. Revenues in Canada are largely determined by a U.S. dollar reference price while expenses are predominantly incurred in Canadian dollars. From time to time the Company may enter into hedging agreements to fix the exchange rate of Canadian to U.S. dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the U.S. dollar; however, if the Canadian dollar declines in value compared to the U.S. dollar, the Company will not benefit from the fluctuating exchange rate.

Reliance on Third Party Operators and Key Personnel

To the extent that the Company is not the operator of its properties, it will be dependent upon other guarantors or third party operations for the timing of activities and will be largely unable to control the activities of such operators. In addition, the Company's success depends, to a significant extent, upon management and key employees. The loss of key employees could have a negative effect on the Company. Attracting and retaining additional key personnel will assist in the expansion of the Company's business. The Company faces significant competition for skilled personnel. There is no assurance that the Company will successfully attract and retain personnel required to continue to expand its business and to successfully execute its business strategy.

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 procured 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 and may delay exploration and development activities.

Seasonality

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities 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.

Operating Hazards

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, and oil spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or in personal injury. In accordance with industry practice, the Company is not fully insured against all of these risks, nor are all such risks insurable. Although Petrobank maintains liability insurance in an amount that it considers adequate and consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event Petrobank could incur significant costs that could have a materially adverse effect upon its financial condition. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Global Economic Conditions

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, may cause 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 through 2010, these factors may impact the performance of the global economy going forward.

Environmental Regulation

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. In certain areas where the Corporation operates, spills, releases and other environmental and safety issues can also occur as a result of sabotage and damage to the pipelines. Depending on the cause and severity of an environmental incident, the Corporation's reputation may also be adversely affected, which could limit our ability to obtain permits and implement our future plans. Although we believe that the Company is 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 our business, financial condition, results of operations and prospects. Additionally, although the Company currently not a party to any material environmental litigation, there can be no assurance that the Company will not become subject to such legal proceedings in the future, which may have a material adverse effect on our 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". Representatives from approximately 170 countries met in Copenhagen, Denmark to attempt to negotiate a successor to the Kyoto Protocol. Pursuant to the resulting Copenhagen Accord, a non-binding political consensus rather than a binding international treaty such as the Kyoto Protocol, the Government of Canada revised its emissions reduction targets slightly. Our exploration and production facilities and other operations and activities emit greenhouse gases and require the Company to comply with Alberta's greenhouse gas emissions legislation contained in the *Climate Change and Emissions Management Act* and the *Specified Gas Emitters Regulation*. We may also be required to comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the Canadian 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 our 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. 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 our operations and financial condition.

Potential Environmental Risks Associated with Hydraulic Fracturing

PetroBakken utilizes horizontal drilling, multi-stage hydraulic fracturing, specially formulated completion fluids and other technologies in connection with its drilling and completion activities. Recently there has been some public concern over the hydraulic fracturing process with regards to shale gas formations in the United States and Eastern Canada. Most of these concerns have raised questions regarding the completion fluids used in the fracturing process, their effect on fresh water aquifers, the use of water in connection with completion operations and the ability of such water to be recycled. Certain government and regulatory agencies in Canada and the United States have begun investigating the potential risks associated with the hydraulic fracturing process.

It is anticipated that federal, provincial and state regulatory frameworks to address concerns related to hydraulic fracturing will continue to emerge. While we are unable to predict the impact of any potential

regulations upon its business, the implementation of new regulations with respect to water usage or hydraulic fracturing generally could increase the Company's costs of compliance, operating costs, the risk of litigation and environmental liability, or negatively impact the Corporation's prospects, any of which may have a material adverse effect on our business, financial condition and results of operations.

Changes in Laws, Regulations or Government Policy

The oil and gas industry in general is subject to extensive government policies and regulations, which result in additional cost and risk for industry participants. Changes in tax and other laws may adversely affect the value of our shares. Income tax laws, royalty rates, other laws or government incentive programs relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects the Company and our shareholders. Tax authorities having jurisdiction over the Company or the shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our shareholders.

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

IFRS will replace previously existing GAAP for Canadian publicly accountable enterprises for financial periods ending after January 1, 2011. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that have been identified. The implementation of IFRS will result in significant adjustments to our financial statements which could negatively impact our business. In particular IFRS requires that testing for whether goodwill and oil and natural gas assets are recoverable at a more granular level which increases the risk of impairment.

Permits, Licenses and Leases

Significant parts of the Company's operations require permits, licenses and leases from various governmental authorities and landowners. There can be no assurance that the Company will be able to obtain all necessary permits, licenses and leases that may be required to carry out exploration and development at its projects. If the present permits, licenses and leases are terminated or withdrawn, such event could have an adversely negative effect of the Company's operations.

Title to Properties

Although title reviews are done according to industry standards prior to the purchase of most 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 claim of Petrobank which could result in a reduction of the revenue received by Petrobank.

Potential Liability Regarding Tax Reassessments

The Company has filed tax returns and issued "flow-through shares" whereby certain tax benefits generated from Petrobank's capital expenditure program have been renounced to investors. Should the Company's tax returns or renouncement's of capital expenditures be audited, there exists a risk that the Company could become liable for incremental income taxes and penalties and could be required to indemnify investors as a result of any reduction in benefits received.

Tax Risk Relating to Petrominerales Reorganization

In connection with the spin-off of Petrominerales, the Company received a tax ruling from the Canada Revenue Agency which confirmed the spin-off was non-taxable to Petrobank. However, there are a number of constraints in the *Income Tax Act* (Canada), which, if breached, could cause the spin-off to be re-characterized as a taxable transaction. A determination by the Canada Revenue Agency that the spin-off transaction is taxable could have a material adverse effect on the Company and its shareholders.

Conflicts of Interest

There are potential conflicts of interest to which the directors, officers and principal shareholders of the Company will be subject to in connection with the operations of the Company. Some of the directors, officers and principal shareholders are or may become engaged in other oil and gas interests on their own behalf and on behalf of other companies, and situations may arise where the directors and officers will be in direct competition with the Company. Conflicts, if any, will be subject to the procedures and remedies under the ABCA. The directors and officers of the Company may not devote their time on a full-time basis to the affairs of the Company. See "*Interest of Management and Others in Material Transactions*" for further information about recent transactions with related parties. Certain directors of the Board and management of Petrobank own collectively, directly and indirectly, a significant part of the outstanding share capital of the Company, and will therefore have the possibility to influence the decision-making in the Company.

Risks Associated With the Heavy Oil Business Unit

Petrobank's Heavy Oil Business Unit is in an early stage of operations using proprietary technology that is in the process of achieving commercialization in a variety of reservoirs. As a result, in addition to the risks set forth above, the Heavy Oil Business Unit is subject to the additional risk factors set forth below.

Intellectual Property Rights

Petrobank's technologies are covered by the registered patents and patent applications described in "*Overview of the Business and Principal Properties - Heavy Oil Business Unit Overview- Intellectual Property*", both concerning the Company's products, the Company's technologies and the territorial protection of the patents. The Company pursues a policy to protect its technologies through applicable patent legislation.

If Petrobank fails to protect its intellectual property rights, competitors may be able to use Petrobank's technology and know-how, and this could weaken the Company's competitive position, reduce revenue and increase costs. The Company relies primarily on a combination of patent, trade secrets, confidentiality procedures and contractual provisions to protect its intellectual property. These laws and procedures provide only limited protection. Petrobank holds and maintains eight patents, including patents pending. Generally speaking, patents may not provide sufficiently broad protection, both regarding scope, territorial protection and otherwise, or they may not be enforceable in actions against alleged infringes. As well, despite precautions that are taken, it may be possible for unauthorized third parties to copy or reverse engineer aspects of the current or future products or to independently develop similar or superior technology or design concerning the patents the Company owns.

The competitive nature of Petrobank's heavy oil business and the importance of technology to the competitors' businesses may enhance the likelihood of being subject to third party claims. Any such claims, even if without merit, could be time consuming, result in potentially significant litigation costs or

damages. A claim against Petrobank could require that Petrobank enter into licensing agreements with the owner of the intellectual property on terms that may or may not be acceptable to Petrobank.

Limited History of Operations

The Company has a relatively short history of heavy oil and bitumen production, and our current projects are in pre-operating phase. The primary activities of the Heavy Oil Business Unit have been the testing of the THAI® technology in our pilot projects and planning, construction, development and investment activities with respect to our current and planned projects. Because of the HBU's limited operating history, it may be difficult to evaluate its prospects. In particular, the ability to evaluate the prospects of the HBU will be limited due to our:

- limited historical financial data relating to the sale of bitumen and heavy oil and our operating costs;
- short duration of operating our wells and facilities;
- limited track record in producing and marketing bitumen and heavy oil; and
- lack of history of generating profits from commercial operations.

Anticipated Performance of our Projects

The recovery of bitumen and heavy oil using the THAI® process is subject to uncertainty. The THAI® process has short operating history and is in the pre-operative stage. Although we have limited data from the Conklin Pilot and the initial two well-pairs of the Kerrobert Project, there can be no assurance that our projects will produce bitumen and heavy oil at the expected levels or on schedule.

As a result of the limited operating history with respect to the THAI® technology, the performance of the Conklin Pilot and Kerrobert Project or the proposed projects on the May River Property and Dawson Property may differ from our expectations. The variances from expectation may include, without limitation:

- the ability to achieve anticipated temperature rates in the reservoir;
- the ability to operate at the expected design rates of production;
- the level of in-situ upgrading of heavy oil and/or bitumen; and
- the reliability and availability of equipment and facilities.

If the facilities do not perform to our expectations or as required by regulatory approvals, we may be required to invest additional capital to correct deficiencies or we may not be able to produce the expected level of production of either bitumen heavy oil. If these expectations are not met, our revenue, cash flows and earnings may be reduced.

As the THAI® projects are the HBU's primary projected source of potential revenue for the near future, any deviation from our expectations in the operation or performance of the projects could compromise our ability to meet our obligations, including making debt repayments and interest payments.

The projects may be subject to delays, interruptions or costs that may materially adversely affect our results of operations. Cost increases and delays may occur due to a number of factors, including without limitation:

- labour disputes, disruptions or declines in productivity;
- engineering and/or procurement performance falling below expected levels of output or efficiency;

- increases in the cost of materials or services;
- changes in project scope or errors in design;
- additional requirements imposed by changes in laws, including environmental laws;
- breakdown or failure of equipment or processes;
- delays in obtaining, or satisfying conditions imposed by, regulatory approvals;
- challenges to our proprietary technology;
- transportation accidents, disruption or delays in availability of transportation services or adverse weather conditions affecting transportation; and
- unforeseen site surface or subsurface conditions or reservoir quality.

Operational Hazards

The operation of our projects will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. We do not and will not carry insurance with respect to all potential casualty occurrences and disruptions. There can be no assurance that our insurance will be sufficient to cover any casualty occurrences or disruptions that may occur in the future. The projects could be interrupted by natural disasters or other events beyond our control. Losses and liabilities arising from uninsured or under-insured occurrences could have a material adverse effect on our projects and, accordingly, on our business, financial condition and results of operations.

Recovering bitumen from oil sands and upgrading the recovered bitumen into synthetic crude oil and other products involve particular risks and uncertainties. Our projects are susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. Severe climatic conditions can cause reduced production and in some situations result in higher costs.

The THAI® process involves high pressure and temperature environments in which our equipment must operate. Equipment failures could delay production and increase costs and potentially result in damage to facilities and liability to third parties and regulators against which we may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Ability to Finance Our Projects

Our planned projects require significant investment prior to any cash being returned to the business in the form of operating cash flow. Potential volatility in the financial sector and in the overall economy means that such capital may be restricted in terms of size, expensive in historical terms, or not available at all. Petrobank currently has cash flows from dividends paid on our PetroBakken shares. However, there can be no assurance that PetroBakken will continue to pay dividends at the same rate or that Petrobank will continue to own 59% of the PetroBakken Shares. If dividends from PetroBakken are not available, sources of financing for our projects will be restricted to our cash flows, credit facility, sale of assets and other available debt or equity financing. Inability to effectively finance our future projects could have a material adverse effect on our business, financial condition or results of operations.

Non-Producing or Undeveloped Reserves and Resources

The substantial majority of the HBU's total reserves and contingent resources are non-producing and/or undeveloped. These reserves and contingent resources may not ultimately be developed or produced, either because it may not be commercially viable to do so or for other reasons. Furthermore, not all of the HBU's undeveloped or developed non-producing reserves or contingent resources may be ultimately produced at the time periods we have planned, at the costs we have budgeted or at all.

Please also see the information under the heading "*Risks and Uncertainties*" in the Company's Management's Discussion and Analysis ("**MD&A**") for the year ended December 31, 2010, which is incorporated herein by reference. The Company's MD&A can be located on SEDAR at www.sedar.com.

DIVIDEND RECORD

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

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Petrobank is authorized to issue an unlimited number of common shares. As at December 31, 2010, there were 106,236,333 common shares issued and outstanding. As at March 30, 2011, there were 106,256,658 common shares issued and outstanding.

The holders of common shares are entitled to receive notice of and to attend any meeting of the shareholders of Petrobank and are entitled to one vote for each common share held (except meetings at which only the holders of another class of shares are entitled to vote). The holders of common shares are entitled to receive dividends, on a pro rata basis, if, as and when declared by the Board and, subject to prior satisfaction of all preferential rights, to participate rateably in the net assets of Petrobank in the event of any liquidation, dissolution or winding up of Petrobank, whether voluntary or involuntary, or other distribution of assets of Petrobank among shareholders for the purpose of winding up its affairs.

Preferred Shares

Petrobank is authorized to issue an unlimited number of Preferred Shares. As at December 31, 2010 and as of the date of this Annual Information Form, there were no Preferred Shares issued and outstanding.

The Preferred Shares may be issued in one or more series and the Board may, by resolution, fix the number of shares in each series and determine the designation, rights, privileges, restrictions and conditions to be attached to shares of each series. The holders of the Preferred Shares are entitled to vote at meetings, to dividends as and when declared by the Board, and, upon liquidation, to receive, out of the net assets of Petrobank, payment in full of the respective amounts which each holder of Preferred Shares paid on the Preferred Shares in preference and priority to any payment on common shares, but such holders shall not be entitled to any further participation in such assets. Preferred Shares series A through C have been previously authorized but currently there are no Preferred Shares outstanding.

NORMAL COURSE ISSUER BIDS

PetroBakken instituted a normal course issuer bid program on May 18, 2010, whereby it could repurchase up to 9,431,255 common shares, representing 5% of the issued and outstanding PetroBakken shares at such time, subject to daily volume limits. As of the date of this Annual Information Form, PetroBakken repurchased and cancelled 1,680,400 common shares at an average cost of $21.68 per share.

MARKET FOR SECURITIES

The Company's outstanding common shares are listed and posted for trading on the TSX under the trading symbol "PBG".

The following table sets forth the monthly price range and volume for Petrobank's common shares on the TSX for the period from January 1, 2010 to December 31, 2010.

Month	Close	Volume
January	$52.83	9,573,672
February	$54.45	7,227,314
March	$55.62	7,989,767
April	$51.23	8,872,111
May	$45.03	11,033,546
June	$37.45	10,061,454
July	$42.35	7,892,051
August	$36.98	10,015,542
September	$41.84	10,368,524
October	$40.59	5,520,824
November	$40.42	11,163,660
December	$25.25[(1)]	16,429,911

Note:

1. The December closing price represents the price of the common shares on December 31, 2010 and reflects a reduction in value resulting from the spin-out of Petrobank's holdings in Petrominerales pursuant to the Petrominerales Reorganization. On December 24, 2010, the last trading day prior to the ex-distribution date for the Petrominerales Reorganization, the closing price for the common shares was $45.00.

DIRECTORS AND OFFICERS

The name, municipality of residence, position and principal occupation of each of the directors and senior officers of Petrobank, as of the date of this Annual Information Form, are as follows:

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Chris J. Bloomer Alberta, Canada	Senior Vice President and Chief Operating Officer, Heavy Oil, and Director	Mr. Bloomer has been the Senior Vice President and Chief Operating Officer, Heavy Oil and Director of Petrobank since May 2007. Prior thereto, Mr. Bloomer was Vice President Heavy Oil and Chief Financial Officer of Petrobank.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Ian S. Brown[(1)] Alberta, Canada	Director	Mr. Brown is a Chartered Accountant with over 20 years experience in the capital markets. Mr. Brown was a Senior Managing Director at Raymond James Ltd. (and predecessor companies) from 1995 to 2005 and previously was Executive Vice President at the Alberta Stock Exchange. Mr. Brown has been a director of the Company since March 18, 2005 and a director of PetroBakken since October 2009.
Peter Cheung Alberta, Canada	Vice President Finance and Chief Financial Officer	Mr. Cheung has been the Vice President Finance and Chief Financial Officer since August 14, 2010. Prior thereto, Mr. Cheung was Treasurer at Compton Petroleum Corporation from September 2009 to August 2010. From October 2009 to September 2009, Mr. Cheung was the founder and Managing Director of a private investment management company. Previously, Peter was Vice President and Treasurer at Pengrowth Energy Trust from May 2005 to October 2008 and Vice President at RBC Capital Markets Energy Investment Banking from January 200 to May 2005.
Louis L. Frank New Hampshire, USA	Director	Mr. Frank has been a director of the Company since September 1993. Since 1992, Mr. Frank has been an independent consultant and President of Recco Inc., an oil and gas development and real estate development company.
Andrea Hatzinikolas Alberta, Canada	Assistant Corporate Secretary and General Counsel	Ms. Hatzinikolas has been the Assistant Corporate Secretary and General Counsel of Petrobank since August 2008. Ms. Hatzinikolas has also been the Corporate Secretary of PetroBakken since July 30, 2009. From February 2007 to August 2008 she was General Counsel of the Company. From 2003 to 2007, Ms. Hatzinikolas was an associate at a national law firm.
M. Neil McCrank[(2)(3)] Alberta, Canada	Director	Mr. McCrank was appointed to the Board of Directors of Petrobank in November, 2008. In June 2008, M. McCrank was appointed as Counsel to Borden Ladner Gervais LLP. From 1998 to 2007, Mr. McCrank was the Chairman of the Alberta Energy and Utilities Board.
Kenneth R. McKinnon[(1)(3)] Alberta, Canada	Director	Mr. McKinnon has been a director of the Company since March 2000, a director of Petrominerales since May 2006 and a director of PetroBakken since October 2009. Mr. McKinnon holds the position of Vice President Legal and General Counsel of Critical Mass Inc., a website design company.
Jerald L. Oaks[(2)] Colorado, USA	Director and Chairman of the Board	On June 15, 2009 Mr. Oaks assumed the position of Chairman of the Board subsequent to Mr. James D. Tocher's passing. Mr. Oaks has been a director of Petrobank since September 1993 and a director of Petrominerales since May 2006. He is a Professional Engineer and President of Oaks Resources Management Inc. since June 1986.

Name and Municipality of Residence	Positions Held	Principal Occupation During Last Five Years
Corey C. Ruttan Alberta, Canada	Director	Mr. Ruttan has been the President and Chief Executive Officer of Petrominerales Ltd. since May 2010. Mr. Ruttan was the Executive Vice President, Chief Financial Officer of PetroBakken from July 2009 to May 2010, Senior Vice President Finance and Chief Financial Officer of Petrobank from November 2008 to May 2010 and Vice President Finance and Chief Financial Officer of Petrominerales Ltd. from May 2006 to May 2010. He served as Vice President Finance and Chief Financial Officer of Petrobank from May 2007 to November 2008, Vice President Finance of Petrobank from May 2006 to May 2007 and Director of Corporate Finance and Investor Relations of Petrobank from July 2003 to May 2006.
R. Gregg Smith Alberta, Canada	Director	Mr. Smith is the President and Chief Operating Officer of PetroBakken. Prior thereto, Mr. Smith was the Senior Vice President and Chief Operating Officer, Canada of Petrobank since November 2008 and the Vice President, Canada from March of 2003 to November 2008. Mr. Smith was appointed as a director of the Corporation on November 11, 2009.
Dr. Harrie Vredenburg[(1)(3)] Alberta, Canada	Director	Dr. Vredenburg is Professor of Strategy and Suncor Energy Chair in Competitive Strategy and Sustainable Development at the Haskayne School of Business at the University of Calgary. Dr. Vredenburg has been a director of the Company since May 2, 2006.
John D. Wright [(2)] Alberta, Canada	President, Chief Executive Officer and Director	Mr. Wright has been President and Chief Executive Officer and a director of the Company since March 2000. Mr. Wright is also the President and Chief Executive Officer of Petrominerales Ltd. and Chairman and Chief Executive Officer of PetroBakken.

Notes:

2. Member of the Audit Committee.
3. Member of the Reserves Committee.
4. Member of the Compensation Committee.
5. The term of office of each director expires at the next annual meeting of shareholders.

As at March 30, 2011, the directors and senior officers of Petrobank, as a group, beneficially owned or exercised control or direction over 6,278,382 common shares constituting approximately 5.9% of the issued and outstanding common shares.

As at March 30, 2011, the directors and senior officers of Petrobank, as a group, also beneficially owned or exercised control or direction over 87,983 common shares of PetroBakken, a 59% owned subsidiary of Petrobank.

CEASE TRADE ORDERS, BANKRUPTCIES, PENALTIES OR SANCTIONS

Except as disclosed herein, to the knowledge of the Company:

(a) no director or executive officer of the Company is as at the date hereof or was within the 10 years prior to the date hereof, a director, chief executive officer or chief financial officer of any company that, while the director or executive officer was acting in such capacity, was subject to any cease trade order or similar order or any order that denied the relevant company from access

to exemptions securities legislation that was in effect for a period of more than 30 consecutive days and (i) was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or (ii) was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer but resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

(b) no director or executive officer of the Company and no security holder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to (i) 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 (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision; and

(c) no director or executive officer of the Company and no security holder holding a sufficient number of securities of the Company to affect materially the control of the Company, or a personal holding company of any such persons, is or has been within the 10 years preceding the date of this Annual Information Form, a director or executive officer of any company, that while that person was acting in such a capacity, or 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.

Corey C. Ruttan

Mr. Corey C. Ruttan entered into a settlement agreement with the Alberta Securities Commission ("**ASC**") on May 3, 2002 in respect of an insider trading violation relating to a May 17, 2000 trade. Mr. Ruttan cooperated completely in resolving the matter with the regulators. The settlement resulted in Mr. Ruttan paying an administrative penalty of $10,000, representing a return of profits, and the costs of the proceeding in the amount of $3,925. For a period of one year, Mr. Ruttan agreed to cease trading in securities and to not act as a director or officer of a public company. These restrictions expired on May 3, 2003. Mr. Ruttan is a Chartered Accountant in good standing.

John D. Wright and Chris J. Bloomer

Mr. John D. Wright and Mr. Chris J. Bloomer are directors of Canadian Energy Exploration Inc. ("**CEE**") (formerly TALON International Energy, Ltd.), a reporting issuer listed on the TSX Venture Exchange. A cease trade order (the "**ASC Order**") was issued on May 7, 2008 against CEE by the ASC for the delayed filing of CEE's audited annual financial statements and management's discussion and analysis for the year ended December 31, 2007 ("**Annual Filings**"). The Annual Filings were filed by CEE on SEDAR on May 8, 2008. As a result of the Order, the TSX Venture Exchange suspended trading in CEE's shares on May 7, 2008. In addition, on June 4, 2009 the British Columbia Securities Commission ("**BCSC**") issued a cease trade order (the "**BCSC Order**") against CEE for the failure of CEE to file its audited annual financial statements and management's discussion and analysis for the year ended December 31, 2008 and its unaudited interim financial statements and management's discussion and analysis for the three months ended March 31, 2009.

CEE made application to the ASC and BCSC for revocation of the ASC Order and BCSC Order. The ASC and BCSC have issued revocation orders dated October 14, 2009 and November 30, 2009,

respectively, granting full revocation of compliance-related cease trade orders issued by the ASC and the BCSC in respect of CEE.

M. Neil McCrank

Mr. McCrank is a director of MegaWest Energy Corp. ("MegaWest"), a reporting issuer in the provinces of Alberta and British Columbia. On September 7, 2010, a cease trade order was issued by the ASC against MegaWest for failure to file its annual audited financial statements, management's discussion and analysis and certification of annual filings for the year ended April 30, 2010 (the "Annual Filings"). On September 8, 2010, the BCSC issued a cease trade order against MegaWest for failure to file the Annual Filings. The Annual Filings were completed by MegaWest in September and October of 2010 and revocation orders were issued by the ASC and BCSC on October 22, 2010.

CONFLICTS OF INTEREST

Certain officers and directors of Petrobank are also officers and/or directors of other companies engaged in the oil and gas business generally. As a result, situations arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of Petrobank. In addition, the ABCA, Petrobank's governing statute, requires that any director or officer of a corporation who is party to, or is a director and officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Company must disclose his or her interest and, in the case of directors, refrain from voting on any matter in respect of such contract, unless otherwise permitted under the ABCA.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

In July 2003, the Company acquired the THAI® and CAPRI® patented heavy oil recovery technologies indirectly from one director of the Company (John D. Wright) and one former director of the Company and a third party, pursuant to an agreement made by an independent committee of the Board. The former director recovered his $226,000 investment and Mr. Wright received cash of $189,000 on his $226,000 investment and retained a 7.5 percent net profits interest in any future third party (non-Petrobank) licensing royalties generated from the technologies.

TRANSFER AGENT AND REGISTRAR

The Company's transfer agent and registrar for the common shares listed on the TSX is Computershare Trust Company of Canada, located at 600, 530 - 8th Avenue SW, Calgary, Alberta T2P 3S8.

MATERIAL CONTRACTS

The Company has not entered into any material contracts that continue to be in effect and are not disclosed herein or were otherwise entered in the ordinary course of business.

INTERESTS OF EXPERTS

Deloitte & Touche LLP, Chartered Accountants, are the Company's auditors and as such have prepared an opinion with respect to the Company's consolidated financial statements as at and for the fiscal year ended December 31, 2010. Deloitte & Touche LLP is independent within the meaning of the Rules of Professional Conduct as outlined by the Institute of Chartered Accountants of Alberta.

Information relating to reserves in this Annual Information Form was calculated by McDaniel and Sproule as independent qualified reserves evaluators. The principals of McDaniel and Sproule, individually or as a group, neither own nor expect to receive any of Petrobank's securities, directly or indirectly.

ADDITIONAL INFORMATION

Additional information relating to the Company may be found on SEDAR at www.sedar.com.

Additional information, including information as to directors' and officers' remuneration, principal holders of the Company's securities, and securities authorized for issuance under equity compensation plans, will be available in the Management Proxy Circular of the Company provided for the annual and special meeting of the shareholders of the Company to be held on May 25, 2011, to be available at www.sedar.com or at www.petrobank.com. Additional financial information is also provided in the Company's consolidated financial statements and Management's Discussion and Analysis for the year ended December 31, 2010 which are contained in the Annual Report of the Company for the year ended December 31, 2010, available at www.sedar.com or at www.petrobank.com.

APPENDIX A

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

Management of Petrobank Energy and Resources Ltd. (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.

Independent qualified reserves evaluators have evaluated the Company's reserves data. The report of the independent qualified reserves evaluators will be filed with securities regulatory authorities concurrently with this 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 evaluators;
(b) met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators to report without reservation, to inquire whether there had been any disputes between the previous independent qualified reserves evaluator, and
(c) reviewed the reserves data with management and the independent qualified reserves evaluators.

The Reserves Committee of the Board of Directors has reviewed the 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 has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data, and
(c) the content and filing of this report.

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

(signed) "***Chris J. Bloomer***"
Chris J. Bloomer
Senior Vice President Heavy Oil and Director

(signed) "***Jerald L. Oaks***"
Jerald L. Oaks
Director and Member of the Reserves Committee

(signed) "***M. Neil McCrank***"
M. Neil McCrank
Director and Member of the Reserves Committee

(signed) "***John D. Wright***"
John D. Wright
President and Chief Executive Officer,
Director and Member of the Reserves Committee

APPENDIX B

FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the Board of Directors of PetroBakken Energy Ltd. (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	Description and Preparation Date of Evaluation Report	Location of Reserves (County)	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 PetroBakken Energy Ltd., as of December 31, 2010, prepared February 18, 2011	Canada				
Total			**Nil**	**4,141,555**	**Nil**	**4,141,555**

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

Executed as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 18, 2011

(signed) "***Paul B. Jung***"
Paul B. Jung, P. Eng.
Senior Petroleum Engineer and Associate

(signed) "***Richard A. Brekke***"
Richard A. Brekke, P. Eng.
Senior Petroleum Engineer and Associate

(signed) "***Scott W. Pennell***"
Scott W. Pennell, P.Eng.
Supervisor, Engineering and Associate

(signed) "***Alec Kovaltchouk***"
Alec Kovaltchouk, P.Geol.
Manager, Geoscience and Associate

(signed) "***Robert N. Johnson***"
Robert N. Johnson, P. Eng.
Vice-President, Engineering and Director

APPENDIX C

FORM 51-101F2
REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

To the Board of Directors of Petrobank Energy and Resources Ltd. (the "**Company**"):

1. We have evaluated the Company's Reserves Data as at December 31, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2010, and identifies the respective portions thereof that we have evaluated, audited and reviewed and reported on to the Company's management:

		Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Preparation Date of Evaluation Report	Location of Reserves	Audited	Evaluated	Reviewed	Total
March 9, 2011	Canada	-	554,759	-	554,759

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(signed) "***P.A. Welch***"
P.A Welch, P. Eng.
President & Managing Director

Calgary, Alberta

Date: March 9, 2011

APPENDIX D

FORM 52-110F1
AUDIT COMMITTEE INFORMATION REQUIRED IN AN AIF

1. **The Audit Committee's Charter**

See Appendix "E" attached to this Annual Information Form for the text of Petrobank's Audit Committee charter.

2. **Composition of the Audit Committee**

Ian S. Brown – independent and financially literate.

Kenneth R. McKinnon – independent and financially literate.

Harrie Vredenburg – independent and financially literate.

3. **Relevant Education and Experience**

Ian S. Brown: Mr. Brown has been a member of the Institute of Chartered Accountants since 1983. Mr. Brown was a Senior Managing Director at Raymond James Ltd. (formerly Goepel McDermid Inc.) from 1995 until December 2005, and was Executive Vice President at the Alberta Stock Exchange from 1986 to 1995. Mr. Brown is also Director of PetroBakken Energy Ltd., Bonavista Energy Trust, Cathedral Energy Services Ltd., the Canadian Investor Protection Fund, Stem Cell Therapeutics Corp. Sembiosys Genetics Inc., and Consolidated Westview Resource Corp. Mr. Brown obtained his Bachelor of Arts from McMaster University in 1979 and his Bachelor of Commerce (Accounting) from the University of Windsor in 1980. Mr. Brown is a Chartered Accountant with over 25 years experience in the financial markets. He has gained significant experience and expertise in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting. He has gained an understanding of Audit Committee functions through his Board and committee experience with other public corporations.

Kenneth R. McKinnon: Mr. McKinnon obtained his Bachelor of Commerce from the University of Calgary (Accounting) in 1980 and obtained his Bachelor of Laws from Queens University in 1983. Mr. McKinnon was Vice President, Finance and Chief Financial Officer of the Company from November 1997 to March 2000. Mr. McKinnon is also a director of PetroBakken Energy Ltd. and Petrominerales Ltd. Over this time he gained experience in analyzing financial statements and he has an understanding of internal controls and procedures for financial reporting and has experience supervising persons engaged in the preparation, analysis and evaluation of financial statements. He has gained an understanding of Audit Committee functions through his involvement with the Company and other public corporations. In 2006, he earned the ICD.D designation of the Institute of Corporate Directors, as a certified corporate director.

Dr. Harrie Vredenburg is Professor of Strategy and Suncor Energy Chair in Competitive Strategy and Sustainable Development at the University of Calgary's Haskayne School of Business and is academic director of the Global Energy Executive MBA program. He is also an International Research Fellow at Oxford University Said Business School. He was the founding director of Haskayne's International Resource Industries and Sustainability (IRIS) from 1994 to 2007. Dr. Vredenburg was the academic chair of the Latin American MSc. program in energy and environment from 1996 to 2006. Before joining the Haskayne School of Business at University of Calgary, Dr. Vredenburg was a professor at McGill University's Desautels Management School. Dr. Vredenburg's research, focused on competitive strategy, innovation and sustainable development in global energy and natural resource industries, has been published in the leading international management journals. Prior to his academic career, Dr. Vredenburg was a financial products marketing manager with American Express in Toronto and New York. For more than 25 years he has worked as a consultant to both corporations and governments. Dr. Vredenburg earned a PhD in strategic management from the Richard Ivey School of Business at the University of Western Ontario in 1986 and holds MBA (International Business and Finance) and BA (History) degrees from McMaster University and the University of Toronto, respectively. In 2005, Dr. Vredenburg earned the ICD.D designation of the Institute of Corporate Directors, as a certified corporate director. He was certified as a mediator by the Consensus Building Institute (Harvard-MIT Public Disputes Program) in 1997.

4. **Reliance on Certain Exemptions**

N/A

5. **Reliance on the Exemption in Subsection 3.3(2) or Section 3.6**

N/A

6. **Reliance on Section 3.8**

N/A

7. **Audit Committee Oversight**

N/A

8. **Pre-Approval Policies and Procedures**

The Audit Committee requires the Company to obtain Audit Committee approval for any non-audit services exceeding immaterial amounts.

9. External Auditor Service Fees (By Category)

Year Ended	Audit Fees	Audit Related Fees[(1)]	Tax Fees[(2)]	All Other Fees
Petrobank	$231,500	$51,000	Nil	Nil
Petrominerales	$249,200	$75,300	Nil	Nil
PetroBakken	$343,000	$39,700	$69,400	Nil
Total 2009	$823,700	$166,000	$69,400	Nil
Petrobank	$120,000	$79,000	$67,000	Nil
Petrominerales	$265,000	$170,000	Nil	Nil
PetroBakken	$308,000	$131,000	$11,500	Nil
Total 2010	$693,000	$380,000	$78,500	Nil

Notes:

1. Audit related fees in 2009 includes costs related to quarterly reviews for Petrobank, Petrominerales and PetroBakken, and prospectus fees related to Petrominerales' secondary share offering in April/May 2009. Audit related fees in 2010 includes costs related to quarterly reviews and IFRS related procedures of Petrobank, Petrominerales and PetroBakken, fees associated with Petrominerales' planned Colombian stock exchange listing and costs relating to the issuance of PetroBakken securities.
2. Tax fees relate to preparation of corporate tax returns, tax research, compliance and miscellaneous tax issues.

APPENDIX E

Approved and adopted by the Board on May 13, 2004, as amended March 11, 2009

PETROBANK ENERGY AND RESOURCES LTD.

AUDIT COMMITTEE OF THE BOARD OF DIRECTORS
MANDATE AND TERMS OF REFERENCE

I. PURPOSE

The primary function of the Audit Committee is to assist the Board of Directors (the "Board of Directors" or "Board") of Petrobank Energy and Resources Ltd. ("Petrobank" or the "Corporation") in fulfilling its responsibilities by reviewing: the financial reports and other financial information provided by Petrobank to any regulatory body or the public; the Corporation's systems of internal controls regarding preparation of those financial statements and related disclosures that management and the Board have established; and the Corporation's auditing, accounting and financial reporting processes generally. Consistent with this function, the Audit Committee should encourage continuous improvement of, and should foster adherence to, the Corporation's policies, procedures and practices at all levels. The Audit Committee's primary objectives are:

To assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

To provide for open communication between directors and external auditors;

To enhance the external auditor's independence;

To increase the credibility and objectivity of financial reports; and

To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Audit Committee, management and external auditors.

II. COMPOSITION

1. The Audit Committee shall be comprised of three or more directors as determined by the Board of Directors, none of whom are members of management of Petrobank and all of whom are "unrelated directors" (as such term is used in the Report of the Toronto Stock Exchange on Corporate Governance in Canada) and "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 52-110") unless the Board shall have determined that the exemption contained in Section 3.6 of MI 52-110 is available and has determined to rely thereon.

2. All of the members of the Audit Committee shall be "financially literate"(as defined in MI 52-110) unless the Board shall determine that an exemption under MI 52-110 from such requirement in respect of any particular member is available and has determined to rely thereon in accordance with the provisions of MI 52-110.

3. The members of the Audit Committee shall be elected by the Board of Directors at the annual organizational meeting of the Board of Directors and remain as members of the Audit Committee until their successors shall be duly elected and qualified.

4. Unless a Chair is elected by the full Board of Directors, the members of the Audit Committee may designate a Chair by majority vote of the full Audit Committee membership.

III. MEETINGS

1. The Audit Committee shall meet at least four times annually, or more frequently as circumstances dictate. As part of its mandate to foster open communication, the Audit Committee should meet at least annually with management and the external auditors in separate executive sessions to discuss any matters that the Audit Committee or each of these groups believe should be discussed privately. The Audit Committee or at least its Chair should meet with the external auditors and management quarterly to review the Corporation's financials consistent with Section IV.2 below. The Chief Financial Officer may, at the discretion of the Audit Committee, be present at meetings of the Audit Committee and may be excused from all or part of any such meetings by the Chairman.

2. Minutes of all meetings of the Audit Committee shall be taken and the Audit Committee shall report the results of its meetings and reviews undertaken and any associated recommendations to the Board of Directors.

3. A quorum for meetings of the Audit Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Audit Committee shall be the same as those governing the Board.

IV. RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties, the Audit Committee shall:

Documents/Reports Review

1. Review and update this Charter, as conditions dictate.

2. Review the financial statements, prospectuses, MD&A, annual information forms ("AIF") and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval where required.

3. Review the reports to management prepared by the external auditors and management's responses.

4. Review of significant auditor findings during the year, including the status of previous audit recommendations.

5. Be satisfied with and periodically assess the adequacy of procedures for the review of corporate disclosure that is derived or extracted from the financial statements.

6. It is the responsibility of the Audit Committee to review, on behalf of the Board, the Corporation’s internal control systems in order satisfy the Audit Committee that the internal control systems are sufficient to reasonably ensure that:

    - controllable, material business risks are identified, monitored and mitigated where it is determined cost effective to do so;

- internal controls over financial reporting are sufficient to meet the requirements under Multilateral Instrument 52-109 of the Canadian Securities Administrators,
- legal, ethical and regulatory requirements are complied with; and
- major issues as to the adequacy of the Corporation's internal controls and any special audit stops adopted in light of material control deficiencies are reviewed with the Audit Committee by the Chief Financial Officer of the Corporation.

External Auditors

7. Be directly responsible for overseeing the work of the external auditors, including the resolution of disagreements between management and the external auditors regarding financial reporting.

8. Recommend to the Board the external auditors to be nominated for appointment by the shareholders.

9. Recommend to the Board the terms of engagement of the external auditor, including their compensation and a confirmation that the external auditors shall report directly to the Audit Committee.

10. On an annual basis, review and discuss with the auditors all significant relationships the auditors have with the Corporation to determine the auditors' independence.

11. Review the performance of the external auditors and approve any proposed discharge of the external auditors when circumstances warrant.

12. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

13. Periodically consult with the external auditors, without the presence of management, about internal controls and the fullness and accuracy of the organization's financial statements.

14. Consider, in consultation with the external auditor, the audit scope and plan of the external auditor.

15. Pre-approve the completion of any non-audit services by the external auditors and determine which non-audit services the external auditor is prohibited from providing and the Audit Committee may delegate to one or more independent members of the Audit Committee the authority to pre-approve non-audit services, provided that such member(s) reports to the Audit Committee at the next scheduled meeting such pre-approval and the member(s) complies with such other procedures as may be established by the Audit Committee from time to time.

Financial Reporting Processes

16. In consultation with the external auditors and management, review the integrity of the organization's financial reporting processes, both internal and external.

17. Consider judgments concerning the appropriateness of the Corporation's accounting policies.

18. Consider and approve, if appropriate, major changes to the Corporation's auditing and accounting principles and practices as suggested by the external auditors or management.

19. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

20. Establish a procedure for:

    · the receipt, retention and handling 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.

21. Approve management recommendations of appointment of individuals to senior financial reporting positions within the Corporation.

Process Improvement

22. Establish regular and separate systems of reporting to the Audit Committee by management and the external auditors regarding any significant judgments made in management's preparation of the financial statements and the view of each group as to appropriateness of such judgments.

23. Following completion of the annual audit, review separately with management and the external auditors any significant difficulties encountered during the course of the audit, including any restrictions on the scope of work or access to required information.

24. Review with external auditors their assessment of internal controls, their written reports containing recommendations for improvement, and management’s response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements.

Ethical and Legal Compliance

25. Ensure that management has the proper review system in place to ensure that the Corporation's financial statements, reports and other financial information disseminated to regulatory organizations and the public satisfy legal requirements.

26. On at least an annual basis, review with the Corporation's counsel and/or management, any legal matters, compliance with applicable laws and regulations, or inquiries received from regulators or government agencies that could have a significant impact on the organization's financial statements.

27. Conduct and authorize investigations into any matters within the Audit Committee's scope of responsibilities. The Audit Committee shall be empowered to retain, and to set and pay compensation for any independent counsel and other professionals to assist in the conduct of any investigation.

28. Perform any other activities consistent with this Charter, the Corporation's by-laws and governing law, as the Audit Committee or the Board of Directors deems necessary or appropriate.