BAYTEX ENERGY TRUST

ANNUAL INFORMATION FORM

2009

MARCH 26, 2010

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APPENDICES:

SELECTED TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Baytex, the **Corporation** or the **Company** means Baytex Energy Ltd.

Baytex ExchangeCo means Baytex ExchangeCo Ltd.

Baytex Partnership means Baytex Energy Partnership, a general partnership, the partners of which are Baytex and Baytex Oil & Gas Ltd.

Baytex USA means Baytex Energy USA Ltd.

Board of Directors means the board of directors of Baytex.

Crew means Crew Energy Inc.

OPEC means the Organization of the Petroleum Exporting Countries.

Operating Entities means the subsidiaries of the Trust that are actively involved in the acquisition, production, processing, transportation and marketing of crude oil, natural gas liquids and natural gas, being Baytex, Baytex Partnership, Baytex Oil & Gas Ltd. and Baytex USA, each a direct or indirect wholly-owned subsidiary of the Trust, and **Operating Subsidiary** means any one of them, as applicable.

SEC means the United States Securities and Exchange Commission.

Trust, **we**, **us** or **our** means Baytex Energy Trust and all its controlled entities on a consolidated basis.

Trustee means Valiant Trust Company our trustee.

Unitholders means holders of our Trust Units.

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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

Sproule means Sproule Associates Limited, independent petroleum consultants of Calgary, Alberta.

Sproule Report means the report prepared by Sproule dated March 19, 2010 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Trust and Baytex Energy USA Ltd. (As of December 31, 2009*)".

Securities and Other Terms

Assignment and Novation Agreement means the assignment and novation agreement made as of January 1, 2010 among us, Baytex and Baytex Partnership.

Convertible Debentures means our 6.50% convertible unsecured subordinated debentures due December 31, 2010 and issued pursuant to the trust indenture dated June 6, 2005 among us, Baytex and Valiant Trust Company.

Credit Facilities means, collectively, the operating loan that Baytex has with a chartered bank and a 364-day revolving loan that Baytex has with a syndicate of chartered banks, in an aggregate amount of $515 million, which each mature on June 30, 2010 (subject to extension thereafter in certain circumstances).

Debentures means our 9.15% series A senior unsecured debentures due August 26, 2016 and issued pursuant to the Indenture.

DRIP means our distribution reinvestment plan.

Exchangeable Shares means the exchangeable shares of Baytex which are exchangeable for Trust Units.

Exchange Ratio means the ratio at which Exchangeable Shares may be converted to Trust Units.

GAAP means generally accepted accounting principles in Canada.

Indenture means the trust indenture dated August 26, 2009 among us, our Operating Entities and Baytex Marketing Ltd. (as guarantors) and Valiant Trust Company.

Notes means the 12% unsecured subordinated promissory notes issued by Baytex and held by us pursuant to the plan of arrangement completed on September 2, 2003 and other promissory notes issued by Baytex or any of our other Operating Entities to us from time to time.

Note Indenture means the note indenture relating to the Notes issued on September 2, 2003.

NPI means the net profit interests in certain petroleum substances owned by Baytex Partnership.

NPI Agreement means the amended and restated net profit interests agreement between us and Baytex made as of September 2, 2003, as further amended by an amending agreement dated January 1, 2010, providing for the creation of the NPI, which NPI Agreement was subsequently assigned by Baytex to Baytex Partnership on January 1, 2010 pursuant to the Assignment and Novation Agreement.

Special Voting Units means the special voting units issued by us entitling holders of Exchangeable Shares to voting rights at meetings of Unitholders.

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

Trust Indenture means the third amended and restated trust indenture between our trustee, Valiant Trust Company, and Baytex made as of May 20, 2008.

Trust Unit or **Unit** means a unit issued by us, each unit representing an equal undivided beneficial interest in our assets.

Trust Unit Rights Incentive Plan means our trust unit rights incentive plan.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
NGL	natural gas liquids
bbl/d	barrels per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units
GJ	gigajoule

Other

BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**
Mboe	thousand barrels of oil equivalent.
MMboe	million barrels of oil equivalent.
boe/d	barrels of oil equivalent per day.
WTI	West Texas Intermediate.
API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity.
$ Million	means millions of dollars.
$000s	means thousands of dollars.

CONVERSIONS

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbl	Cubic metres	0.159
Cubic metres	Bbl	6.293
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.948

CONVENTIONS

Certain terms used herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings in this Annual Information Form as in NI 51-101. Unless otherwise indicated, references in this Annual Information Form to "$" or "dollars" are to Canadian dollars and references to "US$" are to United States dollars. All financial information contained in this Annual Information Form has been presented in Canadian dollars in accordance with GAAP. Words importing the singular number only include the plural, and vice versa, and words importing any gender include all genders. All operational information contained in this Annual Information Form relates to our consolidated operations unless the context otherwise requires.

SPECIAL NOTES TO READER

Forward-Looking Statements

In the interest of providing our Unitholders and potential investors with information about us, including management's assessment of our future plans and operations, certain statements in this Annual Information Form are "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995* and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "**forward-looking statements**"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this Annual Information Form speak only as of the date hereof and are expressly qualified by this cautionary statement.

In addition there are forward looking statements in this Annual Information Form under the headings: "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*" (as to our anticipated conversion to a corporation and related tax matters) and "*Description of Our Business and Operations – Statement of Reserves Data and Other Oil and Gas Information*" (as to our reserves and future net revenues from our reserves, pricing and inflation rates, future development costs, the development of our proved undeveloped reserves and probable undeveloped reserves, future development activities, hedging policies, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates).

Specifically, this Annual Information Form contains forward-looking statements relating to: the taxation of income trusts; our plans to convert our legal structure from a trust to a corporation, the timing of such conversion, the payment of dividends following such conversion, our ability to utilize our tax pools to reduced our taxable income following such conversion and the impact of such conversion on our unitholders; our distribution practice; the portion of our funds from operations to be allocated to cash distributions and our capital program; our ability to maintain production levels by investing approximately half of our internally generated funds from operations; our ability to grow our reserve base and add to production levels through exploration and development activities complemented by strategic acquisitions; our petroleum and natural gas reserves, including the quantum thereof and the present value of the future net revenue to be derived therefrom; development plans for our properties, including number of potential drilling locations, number of wells to be drilled in 2010, initial production rates from new wells and recovery factors; our heavy oil resource play at Seal, including the resource potential of our undeveloped land, initial production rates from new wells, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, our assessment of the viability and economics of a commercial-scale cyclic steam injection project, the timing for completion of a commercial-scale cyclic steam injection project and the ability to recover incremental reserves by reducing inter-well spacing; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates from new wells and average recoveries per well; our working interest production volume for 2010; the existence, operation, and strategy of our commodity price risk management program; funding sources for cash distributions and our capital program; and the impact of existing and proposed governmental and environmental regulation. In addition, information and statements relating to reserves and resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves and resources can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the availability and cost of labour and other industry services; the amount of future cash distributions that we intend to pay; interest and foreign exchange rates; and the continuance of existing and, in certain circumstances, proposed tax and royalty regimes. Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: declines in petroleum and natural gas prices; variations in interest rates and foreign exchange rates; uncertainties relating to the weakened global economy and consequential restricted access to capital, stock market volatility, market valuations and increased borrowing costs; refinancing risk for existing debt and debt service costs; access to external sources of capital; risks associated with our hedging activities; third party credit risk; risks associated with the exploitation of our properties and our ability to acquire reserves; government regulation and control and changes in governmental legislation; changes in income tax laws, royalty rates and other incentive programs; uncertainties associated with estimating oil and natural gas reserves; risks associated with our conversion to a corporate structure; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; the timing of payment of distributions, if any; risks associated with large projects or expansion of our activities; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; risks associated with residency restrictions in the ownership of our Trust Units; changes in climate change laws and other environmental regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the application of accounting policies; the activities of our Operating Entities and their key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonality; our permitted investments; risks associated with our structure and ownership of Trust Units; risks for United States and other non-resident unitholders and other factors, many of which are beyond the control of Baytex.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our 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 statements. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" in this Annual Information Form.

There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

Description of Funds from Operations

This Annual Information Form contains references to funds from operations derived from cash flow from operating activities before changes in non-cash working capital and other operating items. Funds from operations as presented does not have any standardized meaning prescribed by GAAP, and therefore it may not be comparable with the calculation of similar measures for other entities. Funds from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net income or other measures of financial performance calculated in accordance with GAAP.

For more information, see our "*Management's Discussion and Analysis of the operating and financial results*" which includes a definition of "funds from operations" and a reconciliation to cash flow from operating activities and is accessible on the SEDAR website at *www.sedar.com*.

New York Stock Exchange

As a Canadian issuer listed on the New York Stock Exchange (the "**NYSE**"), we are not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a general matter, we are only required to comply with three of the NYSE rules: 1) we must have an audit committee that satisfies the requirements of the *United States Securities Exchange Act of 1934*; 2) our Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE rules; and 3) we must provide a brief description of any significant differences between our corporate governance practices and those followed by U.S. companies listed under the NYSE. We have reviewed the NYSE listing standards applicable to U.S. companies and confirm that our corporate governance practices do not differ significantly from such standards.

Access to Documents

Any document referred to in this Annual Information and described as being accessible on the SEDAR website at *www.sedar.com* (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at 2200, 205 – 5th Avenue S.W., Calgary, Alberta, Canada, T2P 2V7.

BAYTEX ENERGY TRUST

General

We are an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to the Trust Indenture. Our head and principal office is located at Suite 2200, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 2V7.

We were formed on July 24, 2003 and commenced operations on September 2, 2003 as a result of the completion of a plan of arrangement under the *Business Corporations Act* (Alberta) on September 2, 2003 involving us, Baytex, Crew, Baytex Acquisition Corp., Baytex ExchangeCo, Baytex Resources Ltd. and Baytex Exploration Ltd. Pursuant to the plan of arrangement, former holders of common shares of Baytex received common shares of Crew and Trust Units, or Exchangeable Shares or a combination thereof, in accordance with the elections made by such shareholders, and Baytex became a subsidiary of us.

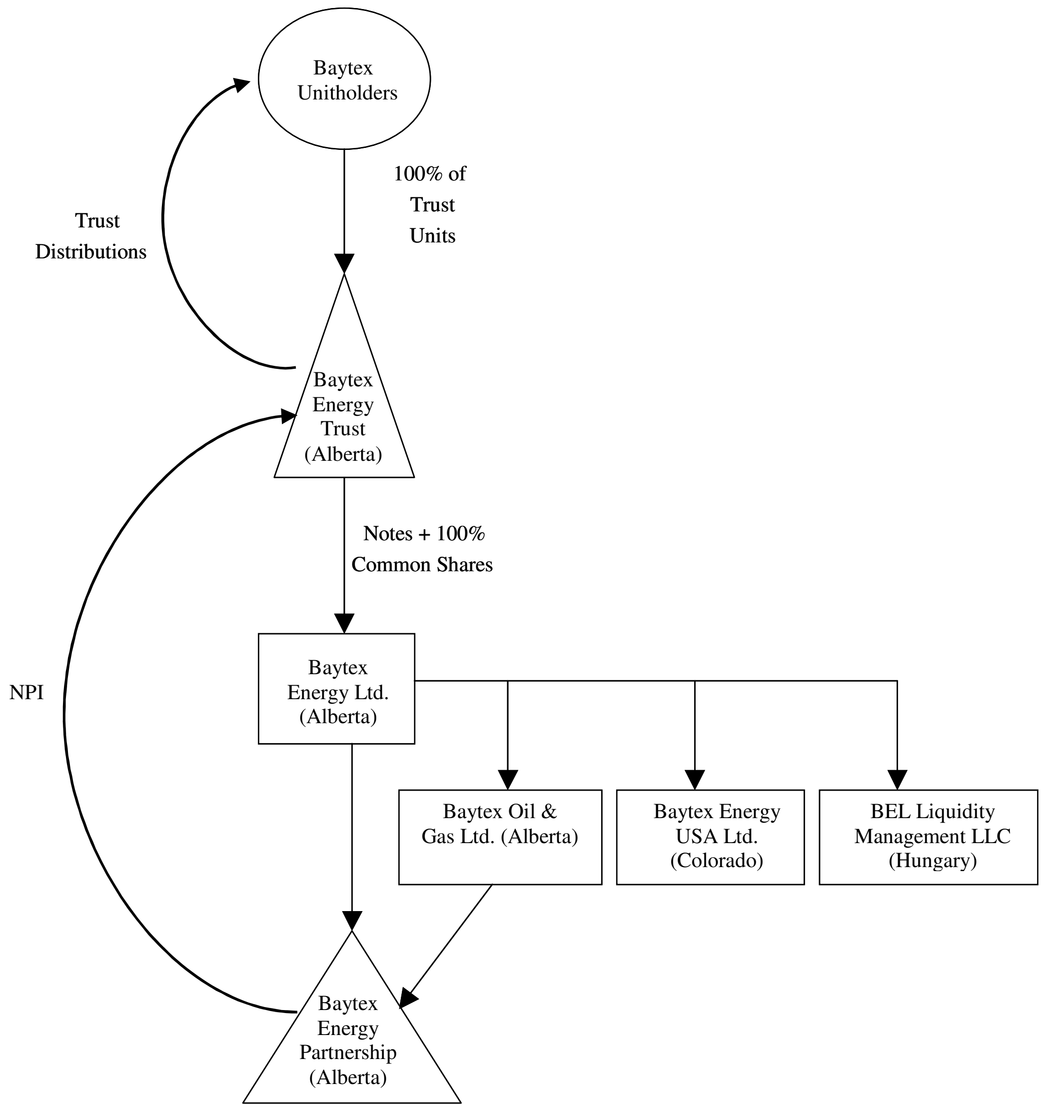
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance, formation or organization of our subsidiaries either, direct and indirect, as at the date hereof.

	Percentage of voting securities (directly or indirectly)	**Jurisdiction of Incorporation/ Formation**
Baytex Energy Ltd.	100%	Alberta
Baytex Energy Partnership	100%	Alberta
Baytex Oil & Gas Ltd.	100%	Alberta
Baytex Energy USA Ltd.	100%	Colorado
BEL Liquidity Management LLC	100%	Hungary

Our Organizational Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries as well as the flow of cash from the oil and gas properties held by such subsidiaries to us and from us to Unitholders.



Note:

(1) Cash distributions are made on a monthly basis to Unitholders based upon our funds from operations. Our primary sources of funds from operations are NPI payments from Baytex Partnership and interest on the principal amount of the Notes and other intercorporate notes. In addition to such amounts, prepayments in respect of principal on the Notes and other intercorporate notes may be made from time to time to us before the maturity of such notes.

Federal Tax Changes for Income Trusts and Corporations

On June 22, 2007, the federal legislation (Bill C-52) (the "**SIFT Rules**") implementing the tax on distributions by certain publicly traded specified investment flow-through trust entities (a "**SIFT**") received Royal Assent. The SIFT Rules are not expected to effect us until 2011 provided we do not exceed the normal growth guidelines announced by the Department of Finance. We can increase our equity by approximately $1,160.7 million before 2011 without exceeding the normal growth guidelines. We do not anticipate that the normal growth guidelines will impair our ability to annually replace or grow reserves in the next year as the guidelines allow sufficient growth targets.

Under the SIFT Rules, the tax rate for a SIFT (the "**SIFT tax**") will be the federal general corporate income tax rate and the applicable provincial corporate rate. The federal general corporate income tax rate will be 16.5 percent in 2011 and 15 percent after 2011 and the provincial component will be 10 percent.

The tax legislation for the conversion of a SIFT into a taxable Canadian corporation on a tax deferred basis received Royal Assent on March 12, 2009.

Management and the Board of Directors continue to work on the plan for converting us to a corporation on or before January 1, 2011. After the conversion, the corporation would expect to allocate its funds from operations among funding a portion of capital expenditures, periodic debt repayments, site reclamation expenditures and cash payments to shareholders in the form of dividends. Current taxes payable by us after converting to a corporation will be subject to normal corporate tax rates. Taxable income as a corporation will vary depending on total income and expenses and vary with changes to commodity prices, costs, claims for both accumulated tax pools and tax pools associated with current year expenditures. As we have approximately $749.7 million of Canadian income tax pools as at December 31, 2009, it is expected that taxable income will be reduced or potentially eliminated for the initial period post-conversion.

Returns to shareholders after conversion to a corporation will be impacted by the reduction of funds from operations required to pay current income taxes, if any. Over the longer term, we would expect Canadian investors who hold their Trust Units in a taxable account to be relatively indifferent on an after-tax basis as to whether we are structured as a corporation or as a trust in 2011. However, Canadian tax deferred investors (those holding their trust units in a tax deferred vehicle such as a registered retirement savings plan, a registered retirement income fund or a pension plan) and foreign investors will realize a lower after-tax return on distributions in taxable years after 2011 due to the introduction of the SIFT tax should we stay as a trust, and their inability to claim the dividend tax credit if we convert to a corporation.

If a conversion from the trust structure to a corporation is approved by the Unitholders, the income tax payable will vary and each Unitholder should consult their own tax advisor for details on the direct impact to themselves.

For more information, see "Risk Factors – Risks Relating to our Business and Operations – Income tax laws, or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders" and "– We are in the process of converting to a corporate structure which may result in adverse consequences to our financial condition".

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On June 15, 2007, we completed a public offering of 7,000,000 subscription receipts (the "**Sub Receipts**") for gross proceeds of $149,450,000. Upon the June 26, 2007 closing of the property acquisition described below, the holders of the Sub Receipts received one Trust Unit in exchange for each Sub Receipt held. The net proceeds of this financing were used to partially fund the acquisition of properties at Pembina and Lindbergh described below.

On June 26, 2007, we completed the indirect acquisition of certain oil and gas producing properties in the Pembina and Lindbergh areas of Alberta for $238 million. These assets were producing approximately 4,500 boe/d of total production at the time of the acquisition. This production was comprised of 2,200 bbl/d of light oil and NGL and 8.0 MMcf/d of natural gas from the Pembina area, and 1,000 bbl/d of heavy oil from the Lindbergh area. The acquisition in the Pembina area allowed us to establish a new core area in the Nisku trend, offering greater exposure to high netback light oil and NGL targets. The assets included 26,000 net acres of undeveloped land in the Pembina area. Lindbergh is a project that offers a large heavy oil resource in place that is amenable to primary (cold) production. Its shallow-depth and multiple zone character provide a low-cost source of recompletion and drilling inventory. In addition to the primarily non-operated producing assets at Lindbergh, we also acquired 11,000 net acres of 100% interest undeveloped land that may include opportunities for shallow natural gas development.

On June 4, 2008, we acquired all of the issued and outstanding shares of Burmis Energy Inc. ("**Burmis**") on the basis of 0.1525 of a Trust Unit for each Burmis common share. Approximately 6.38 million Trust Units were issued pursuant to this transaction, which was valued at approximately $180.5 million. Pursuant to this transaction, we acquired multi-zone, liquids-rich natural gas and light oil properties located in west central Alberta and approximately 110,300 net acres of undeveloped land. Production from the Burmis properties averaged 3,791 boe/d during the first quarter of 2008.

During the third quarter of 2008, we acquired a significant land position in a Bakken/Three Forks light oil resource play in the Williston Basin in northwest North Dakota from a private company (the "**North Dakota Project**"). Upon making all deferred payments associated with the transaction, we will have acquired a 37.5% interest in 263,000 (98,600 net) acres, 94% of which are undeveloped. In addition, we acquired approximately 300 boe/d (95% oil) of production. The seller retained the remaining 62.5% interest in the project lands and production.

On April 14, 2009, we completed a public offering of 7,935,000 Trust Units at a price of $14.50 per Trust Unit for gross proceeds of $115,057,500. The net proceeds of the offering were used to repay outstanding bank indebtedness.

On July 30, 2009, we completed the acquisition of predominantly heavy oil assets located in the Kerrobert and Coleville areas of southwest Saskatchewan, plus certain natural gas assets located in the Ferrier area of west central Alberta effective May 1, 2009. Aggregate cash consideration for the acquisition was $86.2 million, net of adjustments such as net operating income for the interim period from May 1, 2009 to July 30, 2009 and prepaid items. The acquired assets were producing approximately 3,000 boe/d (72% heavy oil and 28% natural gas) at the time of the acquisition. The acquired assets included approximately 47,700 net acres of developed land and 63,300 net acres of undeveloped land in close proximity to our Lloydminster area.

On August 26, 2009, we completed a public offering of $150 million principal amount of 9.15% Series A senior unsecured debentures due August 26, 2016. The net proceeds of the offering along with funds drawn on the Credit Facilities were used to fund the redemption effective September 25, 2009 of the following senior subordinated notes of Baytex: 9.625% notes due July 15, 2010 (principal amount US$179.7 million) and 10.5% notes due February 15, 2011 (principal amount US$0.2 million).

In November, 2009, we reached an agreement with our joint venture partner in the North Dakota Project to pre-pay the remaining deferred acquisition payments. The original participation agreement with the joint venture partner called for deferred acquisition payments totalling approximately US$36 million to be made prior to the spud date of each of the remaining 24 earning wells, occurring more or less rateably until approximately January 2011. On December 15, 2009, we paid our joint venture partner US$33.2 million to complete the remaining deferred acquisition payments and to earn the right to operate a portion of the joint project area effective at the beginning of 2010.

Significant Acquisitions

During the year ended December 31, 2009, we did not complete any acquisitions for which disclosure was required under Part 8 of National Instrument 51-102.

RISK FACTORS

You should carefully consider the following risk factors, as well as the other information contained in this Annual Information Form and our other public filings before making an investment decision. If any of the risks described below materialize, our business, financial condition or results of operations could be materially and adversely affected. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect our business, financial condition or results of operations. Residents of the United States and other non-residents of Canada should have additional regard to the risk factors under the heading "– *Certain Risks for United States and other non-resident Unitholders*".

The information set forth below contains "forward-looking statements", which are qualified by the information contained in the section of this Annual Information Form entitled "*Special Notes to Reader – Forward-Looking Statements*".

Risks Relating to Our Business and Operations

Declines in oil and natural gas prices will adversely affect our financial condition

Our operational results and financial condition, and therefore the amounts we pay to Unitholders as distributions, will be dependent on the prices received for our oil and natural gas production. The extreme volatility of oil and natural gas prices over the past few years has impacted our monthly distributions per Trust Unit, which reached a high of $0.25 for June to November 2008, before being reduced to $0.18 for December 2008 and January 2009 and $0.12 for February to November 2009. With the recovery in oil and natural gas prices, monthly distributions per Trust Unit were increased to $0.18 in December 2009. Declines in oil and natural gas prices will result in further declines in, or elimination of such distributions. Oil and natural gas prices are determined by economic factors and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions in the United States and Canada and worldwide, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, internal capacity to produce natural gas in the United States from shale deposits, the foreign supply of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and funds from operations and ultimately on our financial condition and therefore on the amounts to be distributed to our Unitholders. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Variations in interest rates and foreign exchange rates could affect our ability to service our debt

There is a risk that the interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a decrease in distributions to Unitholders, and could impact the market price of the Trust Units.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that may fluctuate over time and in fact increased by 17% in 2009. A material increase in the value of the Canadian dollar negatively impacts our production revenue and our ability to maintain future distributions. Future Canadian/United States exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

The global economy has not fully recovered and unforeseen events may negatively impact our financial condition

Market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, caused significant volatility to commodity prices over the last few years. These conditions worsened in 2008 and continued in early 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 continue to improve in 2010, these factors have negatively affected company and trust valuations and continue to impact the performance of the global economy going forward.

Our bank credit facility will need to be renewed prior to June 30, 2010 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition

We currently have Credit Facilities in the amount of $515 million. At December 31, 2009, we had approximately $198 million of unused credit available under the Credit Facilities. In the event that the Credit Facilities are not extended before June 30, 2010, indebtedness under the Credit Facilities will be repayable at that date. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms.

As at December 31, 2009, our outstanding indebtedness included $7.8 million of Convertible Debentures which are convertible at the option of the holder at any time into fully-paid Trust Units at a price of $14.75 per unit and mature on December 31, 2010. We intend to partially fund these debt maturities with our existing Credit Facilities; however, we are subject to limitations on the amounts we can draw on our Credit Facilities in order to repay the Convertible Debentures. Subject to certain rights we have under our Credit Facilities to the extent the amounts outstanding thereunder have been reduced by payments sourced from equity issues, asset sales or the unwinding of hedges, the maximum amount we may draw for any such repayments is 20% of the amount of our Credit Facilities and this amount is reduced to nil if the amount drawn on our Credit Facilities exceeds 75% of the amount thereof. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations and distribute cash.

We are required to comply with covenants under the Credit Facilities and the indentures governing the Debentures and Convertible Debentures. In the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required on an accelerated basis by our lenders, and the ability to make distributions to our Unitholders may be restricted. The lenders under the Credit Facilities have security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as breach of our financial covenants, the lenders under the Credit Facilities may foreclose on or sell our working interests in our properties.

Amounts paid in respect of interest and principal on debt may reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants in the agreements with our lenders under the Credit Facilities and the holders of the Debentures may also limit distributions. Although we believe the Credit Facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

We have been historically reliant on external sources of capital, borrowings and equity sales, and if unavailable, our financial condition will be adversely affected

As future capital expenditures will be financed out of funds from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry and our securities in particular.

To the extent that external sources of capital become limited or unavailable or available on onerous terms, our ability to make capital investments and maintain or expand existing assets and reserves may be impaired, and our assets, liabilities, business, financial condition, results of operations and distributions may be materially and adversely affected as a result.

Alternatively, we may issue additional Trust Units from treasury at prices which may result in a decline in production per Trust Unit and reserves per Trust Unit or may wish to borrow to finance significant acquisitions or development projects to accomplish our long term objectives on less than optimal terms or in excess of our optional capital structure.

We believe that estimated funds from operations, together with the existing credit facility, will be sufficient to substantially finance our current operations, distributions to Unitholders and planned capital expenditures for the ensuing year. The timing of most of our capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distributions is also discretionary, and we have the ability to modify distribution levels should funds from operations be negatively impacted by a reduction in commodity prices or other factors. However, if funds from operations is lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties or a decrease in distributions.

Our hedging activities may negatively impact our income and our financial condition

We may manage the risk associated with changes in commodity prices by entering into petroleum or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. As at December 31, 2009, our balance sheet reflected $25.9 million of net unrealized gains resulting from hedges to protect our commodity risk exposure. For more information in relation to our commodity hedging program, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Gas Information – Forward Contracts*". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

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

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, third party operators, marketers of our petroleum and natural gas production, hedge counterparties and other parties. We manage this credit risk by entering into sales contracts with only creditworthy entities and reviewing our exposure to individual entities on a regular basis. However, in the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Our ability to maintain distributions is dependent on a number of factors including volatility of prices for oil and gas, interest rates, sources of capital, changes in legislation and those set forth below

Our ability to add to our oil and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce petroleum and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project.

Higher operating costs for our underlying properties will directly decrease the amount of cash flow received by us and, therefore, may reduce distributions to our Unitholders. Labour costs, electricity, gas processing, well servicing and chemicals are a few of our operating costs that are susceptible to material fluctuation. There is no assurance that further commercial quantities of petroleum and natural gas will be discovered or acquired by us.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline, which will result in a reduction in the value of Trust Units and in a reduction in funds from operations available for distributions to Unitholders.

Our business is heavily regulated and such regulation increases our costs and may adversely affect our financial condition

Oil and natural gas operations (including land tenure, exploration, development, production, refining, pricing, transportation and marketing) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to prices, taxes, royalties and the exportation of oil and natural gas. Regulation increases our costs. In order to conduct oil and gas operations, we require licenses and permits from various governmental authorities. There can be no assurance that we will be able to obtain all of the licenses and permits that may be required to conduct operations that we may wish to undertake. See "*Industry Conditions*".

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

We expect to continue to qualify as a mutual fund trust for purposes of the Tax Act. We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status.

Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders, including income generated by the NPI held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.

- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws.

- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

- Trust Units could cease to be a qualified investment for registered retirement savings plans ("**RRSPs**"), registered education savings plans ("**RESPs**"), deferred profit sharing plans ("**DPSPs**"), registered disability savings plans ("**RDSPs**"), tax free savings accounts ("**TFSAs**") and registered retirement income funds ("**RRIFs**"). Where, at the end of a month, a RRSP, DPSP, RESP or RRIF holds Trust Units that cease to be a qualified investment, the plan must, in respect of that month, pay a tax equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the plan. Trusts governed by RRSPs, RDSPs, TFSAs or RRIFs which hold Trust Units that are not qualified investments will be subject to tax on the income attributable to the Trust Units while they are not qualified investments, including the full capital gains, if any, realized on the disposition of such Trust Units. Where a trust governed by a RRSP or a RRIF acquires Trust Units that are not qualified investments, the value of the investment is included in the income of the annuitant for the year of the acquisition. Trusts governed by RESPs which hold Trust Units that are not qualified investments can have their registration revoked by the Canada Revenue

Agency. The holder of a RDSP or TFSA which holds Trust Units that are not qualified investments will be subject to tax equal to 50% of the fair market value of the Trust Units.

In addition, we may take certain measures in the future to the extent we believe necessary to ensure that we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the Tax Act. See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Non-resident Unitholders*".

Tax authorities having jurisdiction over us or Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment or the detriment of Unitholders.

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. All of such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition or results of operations or prospects and our ability to maintain distributions.

There are numerous uncertainties inherent in estimating quantities of recoverable petroleum and natural gas reserves, including many factors beyond our control

Although we, together with Sproule, have carefully prepared the reserves figures included in this Annual Information Form and believe that the methods of estimating reserves have been verified by operating experience, such figures are estimates and no assurance can be given that the indicated levels of reserves will be produced.

In general, estimates of economically recoverable petroleum and natural gas reserves and resources and the future net revenues therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of petroleum and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. All such estimates are based on professional judgment and classifications of reserves, which, by their nature have a high degree of subjectivity. For those reasons, estimates of the economically recoverable oil and natural gas reserves or estimates of resources attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary.

The reserves and recovery information contained in the Sproule Report is only an estimate and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by Sproule and such variations could be material. The Sproule Report has been prepared using certain commodity price assumptions which are described in the notes to the reserves tables. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in the Sproule Report, the present value of estimated future net revenues for our reserves and our net asset value would be reduced and the reduction could be significant. The estimates in the Sproule Report are based in part on the timing and success of activities we intend to undertake in future years. The reserves and estimated cash flows to be derived therefrom contained in the Sproule Report will be reduced, in future years, to the extent that such activities do not achieve the level of success assumed in the Sproule Report.

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

We are in the process of converting to a corporate structure which may result in adverse consequences to our financial condition

New federal legislation passed in June 2007, will apply a tax at the trust level on distributions of certain income from trusts, such as us, at rates of tax comparable to the combined federal and provincial corporate tax and will treat such distributions as dividends to the Unitholders effective January 1, 2011. The SIFT tax results in adverse tax consequences to us and certain Unitholders (including most particularly Unitholders that are tax deferred or non-residents of Canada) and may impact our distributions.

The SIFT tax will substantially eliminate the competitive advantage that we and other Canadian energy trusts enjoyed relative to their corporate peers in raising capital in a tax-efficient manner, and will make the Trust Units less attractive as an acquisition currency. As a result, it may become more difficult for us to compete effectively for acquisition opportunities. There can be no assurance that we will be able to reorganize our legal and tax structure to substantially mitigate the expected impact of the SIFT tax.

No assurance can be provided that the SIFT tax will not apply to us prior to January 1, 2011, or that the legislation will not be further changed in a manner which adversely affects us and our Unitholders. For more information, see "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*".

Acquiring, developing and exploring for oil and natural gas involves many risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome

These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, equipment failures and other accidents, sour gas releases and spills, uncontrollable flows of oil, natural gas or well fluids, the invasion of water into producing formations, adverse weather conditions, pollution, other environmental risks, fires, spills and delays in payments between parties caused by operation or economic matters which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards, all of which could result in liability. These risks will increase as the Trust undertakes more exploratory activity. Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition.

Exploration and development risks arise due to the uncertain results of searching for and producing petroleum and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploration efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns.

Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property. Other companies operate some of the properties in which we have an interest and as a result our returns on assets operated by others depends upon a number of factors outside our control. To the extent the operator fails to perform these functions properly, operating income may be reduced. In addition, payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Our return on assets operated by others will therefore depend upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of the properties, and by the operator to our Operating Entities, payments between any of such parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses.

Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations, prospects and our ability to maintain distributions.

The marketability of petroleum and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond our control

These factors include demand for petroleum and natural gas, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas and political events throughout the world that cause disruptions in the supply of oil. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue. In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

Our Board of Directors has discretion in the payment of distributions and may not choose to maintain distributions in certain circumstances

The Trust Indenture provides that all of our distributable income at the end of any calendar month including December 31 shall be declared payable and distributed to Unitholders of record on the last day of each such calendar month. The distribution by us of such distributable income is enforceable by such Unitholders of record. However, if this amount is not determined and declared payable in accordance with the rules of the Toronto Stock Exchange, the right to receive this income will trade with the Trust Units. The Trust Indenture provides that this distributable income is allocated to Unitholders for tax purposes and to the extent a Unitholder trades Trust Units in this period, they will be allocated such income but will have disposed of their right to receive such distribution.

In addition, the Trust Indenture provides that such distributable income may be paid in Trust Units. The Trust Indenture also provides for the consolidation of the Trust Units in the discretion of our Board of Directors to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all Unitholders. Accordingly, the Trust Indenture allows for the payment of distributions in a form other than cash and Unitholders may have taxable income and cash taxes payable.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We manage a variety of small and large projects in the conduct of our business. Project delays may impact expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

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

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

We only operate in western Canada and the United States and expansion outside of these areas may increase our risk exposure

Our operations and expertise are currently primarily focused on oil and gas production and development in the Western Canadian Sedimentary Basin and the United States. In the future, we may acquire oil and gas properties outside of these geographic areas. In addition, the terms of the Trust Indenture do not limit us to oil and gas production and development, and we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our business, financial condition or results of operations.

We may not be able to realize the anticipated benefits of acquisitions and dispositions or to manage growth

We make acquisitions and dispositions of businesses and assets in the ordinary course of our business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our operations. There is no assurance that we will be able to continue to complete acquisitions or dispositions of oil and natural gas properties which realize all the synergistic benefits.

We periodically dispose of non-core assets so that management can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain of our non-core assets, if disposed of, could be expected to realize less than their carrying value on our financial statements.

The price we pay for the purchase of any material properties is based on several criteria, including engineering and economic estimates of the reserves made by independent engineers modified to reflect our technical and economic views. These assessments include a number of material factors and assumptions. Many of these factors are subject to change and are beyond our control. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and distributions to Unitholders. See "*Baytex Energy Trust – General Development of the Business*".

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

We have the authority to impose restrictions on the issuance of Trust Units to, or the transfer by any Unitholder, of Trust Units to a non-resident

We intend to comply with the requirements under the Tax Act for "unit trusts" and "mutual fund trusts" at all relevant times such that we maintain our status of a unit trust and a mutual fund trust for purposes of the Tax Act. In this regard, we may, from time to time, among other things, take all necessary steps to monitor our activities and ownership of the Trust Units. If at any time we become aware that our activities and ownership of the Trust Units by non-residents (non-residents of Canada and partnerships) may threaten our status under the Tax Act as a "unit trust" or "mutual fund trust", we are authorized to take such action as may be necessary in our opinion to maintain our status as a unit trust and a mutual fund trust, including the imposition of restrictions on the issuance by the Trust, or the transfer by any Unitholder, of Trust Units to a non-resident. See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Non-resident Unitholders*".

Climate change laws and related environment regulation may impose restrictions or costs on our business which may adversely affect our financial condition and our ability to maintain distributions

Nearly all aspects of our operations 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 or 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. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions – Climate Change Regulation*".

There has been much public debate with respect to the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies by either the provinces in which we operate our business or by the Government of Canada, and whether to meet international agreed limits, or as otherwise determined, for reducing greenhouse gases could have a material impact on the nature of oil and natural gas operations, including ours. 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 either the nature of those requirements or the impact on us and our operations and financial condition. Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated environmental and reclamation obligations, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations from such funds.

Although we believe that we are in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production, a reduction of product demand, a material increase in the costs of production, development or exploration activities or otherwise adversely affect our business, financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations and prospects. See "*Industry Conditions – Climate Change Regulation*".

There is strong competition relating to all aspects of the oil and gas industry

There are numerous trusts and other companies in the oil and gas industry, who are competing with us for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms. Many of these other oil and gas companies have significantly greater financial and other resources than we do.

We compete with other oil and gas entities to hire and retain skilled personnel necessary for running our daily operations including planning, capitalizing on available technical advances and the execution of our exploration and development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

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

Application of GAAP or US GAAP to our financial results may result in non-cash losses which may adversely affect the market price of our Trust Units

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in our consolidated financial statements. 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 may result in an inability to borrow funds and/or may result in a decline in the market price of our Trust Units.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net revenues from reserves. If net capitalized costs exceed the estimated recoverable amounts, we will have to charge the amounts of the excess to earnings. 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. The net value of oil and gas properties are highly dependent upon the prices for petroleum and natural gas.

Under US GAAP, companies using the full cost method of accounting for oil and gas producing activities perform a ceiling test on each cost centre using discounted estimated future net revenue from proved oil and natural gas reserves using a discount rate of 10 percent. Prices used in the US GAAP ceiling tests are based on the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period.. For further information, see Note 21 of our audited consolidated financial statements for the year ended December 31, 2009 which is incorporated by reference in this Annual Information Form and which has been filed on SEDAR at www.sedar.com.

Under GAAP, the accounting for derivatives may result in non-cash charges against net income as a result of changes in the fair market value of derivative instruments. A decrease in the fair market value of the derivative instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

Our success depends in large measure on the activities of our Operating Entities and their key personnel

We are a limited purpose trust and are entirely dependent upon the operations and assets of our Operating Entities through our ownership, directly and indirectly, of securities of our Operating Entities, including the Notes, and the NPI. Accordingly, our ability to pay distributions to Unitholders is dependent upon the ability of our Operating Entities to meet their interest, principal, dividend and other distribution obligations on their securities and to pay the NPI. Our Operating Entities' income is derived from the production of oil and natural gas from their resource properties and is susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. If the oil and natural gas reserves associated with our Operating Entities' resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of our Operating Entities to meet their obligations to us and our ability to pay distributions to Unitholders may be adversely affected.

The loss of key personnel of our Operating Entities could delay the completion of certain projects or otherwise have a material adverse effect on us. Unitholders will be dependent on our management in respect of the administration and management of all matters relating to our properties, the NPI, the Trust Units and the safekeeping of our primary workspace and computer systems. As of December 31, 2009, we operated approximately 93 percent of the total daily production of our properties. Investors who are not willing to rely on our management should not invest in our Trust Units.

Our petroleum and natural gas reserves are a depleting resource and decline as such reserves are produced

Distributions of distributable income in respect of properties, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical petroleum and natural gas reserves. Our future petroleum and natural gas reserves and production, and therefore our funds from operations, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production may decline over time as reserves are produced.

We also distribute a significant proportion of our funds from operations to Unitholders rather than reinvesting it in reserves additions. Accordingly, if external sources of capital, including the issuance of additional Trust Units, become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our petroleum and natural gas reserves may be impaired. To the extent that we use funds from operations to finance capital expenditures or property acquisitions, the level of funds from operations available for distribution to Unitholders will be reduced. There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

Securing and maintaining title to our properties is subject to certain risks

Our properties are held in the form of licenses and leases and working interests in licenses and leases. If we or the holder of the license or lease fails to meet the specific requirement of a license or lease, the license or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each license or lease will be met. The termination or expiration of a license or lease or the working interest relating to a license or lease may have a material adverse affect on our results of operations and business. In addition title to the properties can become subject to dispute and defeat our claim to title over certain of our properties.

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada and have also made claims that certain developments, including oil and gas exploration and development, may have been proceeding without the Crown carrying out appropriate consultations in the course of allowing such developments to proceed. We are not aware that any material claims have been made in respect of our properties and assets; however, if a claim arose and was successful this could have an adverse effect on us and our operations.

We are affected by seasonality

The level of activity in the Canadian oil and natural 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 natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

Our permitted investments may be risky

An investment in the Trust should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy-related income trusts, companies and partnerships will be subject to the general risks of investing in equity securities. These include the risk that the financial condition of issuers may become impaired, or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors, including governmental, environmental and regulatory policies, inflation and interest rates, economic cycles, and global, regional and national events. The value of Trust Units could be affected by adverse changes in the market values of such investments.

Risks Relating to Our Structure and Ownership of Trust Units

Distributions do not represent a "yield" and are not comparable to debt instruments and rights of redemption have limited liquidity

Our Trust Units will have no value when reserves from our properties can no longer be economically produced or marketed and, as a result, distributions do not represent a "yield" in the traditional sense and are not comparable to bonds or other fixed yield securities, where investors are entitled to a full return of the principal amount of debt on maturity in addition to a return on investment through interest payments. Distributions represent a blend of return of Unitholders initial investment and a return on Unitholders initial investment.

Unitholders have a limited right to require a repurchase of their Trust Units, which is referred to as a redemption right. It is anticipated that the redemption right will not be the primary mechanism for Unitholders to liquidate their investment. The right to receive cash in connection with a redemption is subject to material limitations. Any securities which may be distributed *in specie* to Unitholders in connection with a redemption may not be listed on any stock exchange and a market may not develop for such securities and such securities may be illiquid. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Redemption Right*".

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in Baytex

The Trust Units represent a fractional interest in us. Corporate law does not govern the Trust and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring oppression or derivative actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada), the *Companies' Creditors Arrangement Act* (Canada) and in some cases the *Winding Up and Restructuring Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation. Our sole assets will be the NPI and other investments in securities. The price per Trust Unit is a function of anticipated distributable income, the properties acquired by us and our ability to effect long-term growth in our value. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, we are not a trust company and, accordingly, are not registered under any trust and loan company legislation as we do not carry on or intend to carry on the business of a trust company.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have no value when reserves from our properties can no longer be economically produced or marketed. Unitholders will only be able to obtain a return of the capital they invested during the period when reserves may be economically recovered and sold. Accordingly, the distributions received over the life of the investment may not be equal to or greater than the initial capital investment.

Unitholder limited liability is subject to contractual and statutory assurances which may have some enforcement risks

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with us or our obligations and affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of our assets. Pursuant to the Trust Indenture, we will indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges and losses suffered by a Unitholder resulting from or arising out of such Unitholder not having such limited liability.

The Trust Indenture provides that all written instruments signed by or on behalf of the Trust must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. The principal investment of the Trust is the NPI which contains such provisions. Personal liability may also arise in respect of claims against us that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability of this nature arising is considered unlikely. The *Income Trusts Liability Act* (Alberta) came into force on July 1, 2004. The legislation provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after the legislation came into force.

Our operations will be conducted, upon the advice of counsel, in such a way and in such jurisdictions as to avoid as far as possible any material risk of liability on Unitholders for claims against us.

Certain Risks for United States and other non-resident Unitholders

There is limited liability of residents in the United States to enforce civil remedies

We are a trust organized under the laws of Alberta, Canada and our principal place of business is in Canada. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgements of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgements of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

There are differences in reporting practices in Canada and the United States

We report our production and reserve quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not generally included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties); however, we also follow the United States practice of separately reporting reserve volumes on a net basis (after the deduction of royalties and similar payments). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves; whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We included in this Annual Information Form estimates of proved and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this Annual Information Form may not be comparable to United States standards.

As a consequence of the foregoing, our reserve estimates and production volumes in this Annual Information Form may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

The Tax Act and the tax treaties between Canada and other countries may impose additional withholding or other taxes on the distributions or other property paid by us to Unitholders who are non-residents of Canada, and these taxes may change from time to time. Since January 1, 2005, a 15 percent Canadian withholding tax is applied to the return of capital portion of distributions made to non-resident Unitholders.

Additionally, the reduced "Qualified Dividend" rate of 15 percent tax applied to our distributions under current U.S. tax laws is scheduled to expire at the end of 2010 and there is no assurance that this reduced tax rate will be renewed by the U.S. government at such time.

Furthermore, it is anticipated that the implementation of the SIFT tax may have tax consequences for non-residents of Canada that are more adverse than the tax consequences to other classes of Unitholders.

There is a foreign exchange risk for non-resident Unitholders

Our distributions are declared in Canadian dollars and converted to foreign denominated currencies at the spot exchange rate at the time of payment. As a consequence, investors are subject to foreign exchange risk. To the extent that the Canadian dollar strengthens with respect to their currency, the amount of the distribution will be reduced when converted to their home currency.

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

Overview

We are an open-ended, unincorporated investment trust created under the laws of the Province of Alberta pursuant to the Trust Indenture. We were established to, among other things:

- invest in shares of Baytex and acquire the common shares of Baytex and the Notes pursuant to the plan of arrangement which was completed on September 2, 2003;
- acquire the NPI under the NPI Agreement;
- acquire or invest in other securities of Baytex and in the securities of any other entity including, without limitation, bodies corporate, partnerships or trusts;
- dispose of any part of the property of the Trust, including, without limitation, any securities of Baytex;
- temporarily hold cash and investments for the purposes of paying the expenses and the liabilities of the Trust, make other permitted investments under the Trust Indenture, pay amounts payable by the Trust in connection with the redemption of any Trust Units, and make distributions to Unitholders; and
- pay costs, fees and expenses associated with the foregoing purposes or incidental thereto.

We are prohibited from acquiring any investment which (a) would result in the cost amount to us of all "foreign property" (as defined in the Tax Act) which is held by us to exceed the amount prescribed by applicable tax laws or (b) would result in us not being considered either a "unit trust" or a "mutual fund trust" for purposes of the Tax Act.

Our principal undertaking is to issue Trust Units and other securities and to acquire and hold securities of subsidiaries, trusts and partnerships, net profits interests, royalties, notes and other interests. Our Operating Entities carry on the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and assets related thereto in Canada (primarily in the provinces of British Columbia, Alberta and Saskatchewan) and in the United States (primarily in the states of North Dakota and Wyoming). Cash flow from the business carried on by our Operating Entities is flowed to us by way of interest and principal repayments on the Notes and income earned under the NPI.

The Trustee may declare payable to Unitholders all or any part of our income. Currently the only income we receive is from the interest and principal payments received on the Notes and NPI payments. We make monthly cash distributions to Unitholders on our income, after expenses, if any, and any cash redemptions of Trust Units. Cash distributions are made on or about the 15^{th} day following the end of each calendar month to Unitholders of record on or about the last business day of each such calendar month. Our current distribution practice targets the use of between 50 to 60 percent of our funds from operations for capital expenditures to fund both exploration and development expenditures and minor property acquisitions, but excludes major acquisitions.

Pursuant to various agreements with Baytex's lenders, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on us or on our or our subsidiaries' ability to fulfill their obligations under the Credit Facilities or upon a material borrowing base shortfall or default.

Our Debentures also contain certain limitations on maximum cumulative distributions. Restricted payments include the declaration or payment of any dividend or distribution by us and the payment of interest or principal on subordinated debt owed by us. We and certain of our subsidiaries are restricted from making any restricted payments unless at the time of, and immediately after giving effect to, the proposed restricted payment, no default or event of default under the Indenture has occurred and is continuing, and either: (i) (a) we could incur at least $1.00 of additional indebtedness (other than certain permitted debt) in accordance with the "Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock" covenant in the Indenture; (b) the ratio of consolidated debt to consolidated cash flow from operations does not exceed 3.0 to 1.0; and (c) the aggregate amount of all restricted payments declared or made after August 26, 2009 (other than certain permitted restricted payments) does not exceed the sum of: (A) 80% of consolidated cash flow from operations accrued on a cumulative basis since August 26, 2009, plus (B) 100% of the aggregate net cash proceeds received by us after August 26, 2009 from (x) the issuance by us of convertible debentures, or (y) capital contributions in respect of certain permitted equity that we receive from any person; plus (C) the aggregate net proceeds, including the fair market value of property received after August 26, 2009 other than cash (as determined by the Board of Directors), received by us from any person, other than a subsidiary, from the issuance or sale of debt securities (including convertible debentures) or disqualified stock that have been converted into or exchanged for certain permitted equity of us, plus the aggregate net cash proceeds received by us at the time of such conversion or exchange; or (ii) the aggregate amount of all restricted payments declared or made pursuant to paragraph (i) does not exceed the sum of certain unpaid funds from restricted payments not previously expended under paragraph (i), plus $50,000,000.

Baytex Energy Ltd.

Baytex Energy Ltd. is amalgamated under the *Business Corporations Act* (Alberta) and is actively engaged in the business of oil and natural gas exploration, exploitation, development, acquisition and production in Canada. We are the sole common shareholder of Baytex.

The head office of Baytex is located at Suite 2200, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 2V7 and its registered office is located at Suite 1400, 350 – 7th Avenue S.W., Calgary, Alberta T2P 3N9.

NPI

Effective January 1, 2010, we are a party to the NPI Agreement with Baytex Partnership pursuant to which we have the right to receive a NPI on certain petroleum and natural gas rights owned by Baytex Partnership (the "**NPI Properties**"). Pursuant to the terms of the NPI Agreement, we are entitled to a payment from the owner of the NPI Properties for each month equal to the amount by which 99 percent of the gross proceeds from the sale of production attributable to the NPI Properties for such month exceed 99 percent of certain deductible costs for such period. The owner of the NPI Properties is entitled to set off amounts reimbursable to it against NPI payments payable by it. The term of the NPI Agreement is for so long as there are petroleum and natural gas rights to which the NPI applies.

Notes

A Note was issued by Baytex to us under the Note Indenture in connection with the plan of arrangement completed on September 2, 2003. The Note is unsecured, payable on demand and bears interest from the date of issue at an interest rate equal to 12 percent per annum. Interest is payable for each month during the term on the 10th day of the month following such month.

Although Baytex is permitted to make payments against the principal amount of the Notes outstanding from time to time without notice or bonus, Baytex is not required to make any payment in respect of principal until December 31, 2033, subject to extension in limited circumstances.

In contemplation of the possibility that additional Notes may be distributed to Unitholders upon the redemption of their Trust Units, the Note Indenture provides that if persons other than us (the "**Non-Fund Holders**") own Notes having an aggregate principal amount in excess of $1,000,000, either we or the Non-Fund Holders will be entitled, among other things, to require the trustee appointed under the Note Indenture to exercise the powers and remedies available under the Note Indenture upon an event of default and either we or the Non-Fund Holders may provide consents, waivers or directions relating generally to the variance of the Notes Indenture and the rights of noteholders. The Note Indenture allows Baytex the flexibility to delay payments of interest or principal otherwise due to us while payment is made to the Non-Fund Holders, and to allow the Non-Fund Holders to be paid out before us. Any delayed payments will be due five days after demand.

From time to time we advance funds to our controlled entities which are evidenced by promissory notes. The terms of the notes are set at the time of issue. All of these advances are subordinate to all senior indebtedness to our senior lenders.

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated December 31, 2009. The statement is effective as of December 31, 2009 and the preparation date of the statement by Sproule is March 19, 2010. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Sproule in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2009 as contained in the Sproule Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any hedging activities. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Sproule was engaged by us to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. See also "*Definitions and Other Notes to Reserve Data Tables*" below.

Our reserves are located in Canada, specifically in the provinces of Alberta, British Columbia and Saskatchewan, and in the United States, specifically in the states of North Dakota and Wyoming.

All evaluations of future net revenue are after the deduction of future income tax expenses (unless otherwise noted in the tables), royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the Sproule Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. The recovery and reserve estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" in conjunction with the following tables and notes. For more information as to the risks involved, see "*Risk Factors*".

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED:						
Developed Producing	4,584.2	3,373.3	31,357.7	25,997.0	1,989.3	1,450.3
Developed Non-Producing	487.4	368.6	16,333.8	13,782.6	515.9	373.7
Undeveloped	3,789.3	2,813.6	49,363.0	41,952.9	312.9	225.5
TOTAL PROVED	8,860.9	6,555.5	97,054.5	81,732.5	2,818.1	2,049.5
PROBABLE	4,232.3	2,964.8	48,542.3	40,959.7	1,500.2	1,083.6
TOTAL PROVED PLUS PROBABLE	13,093.2	9,520.3	145,596.8	122,692.2	4,318.3	3,133.1

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	68,234.4	57,240.4	49,303.6	40,360.7
Developed Non-Producing	11,780.3	8,882.0	19,300.5	16,005.2
Undeveloped	7,140.3	5,632.8	54,655.3	45,930.8
TOTAL PROVED	87,155.0	71,755.2	123,259.4	102,296.7
PROBABLE	41,044.5	32,544.8	61,115.6	50,432.2
TOTAL PROVED PLUS PROBABLE	128,199.5	104,300.0	184,375.0	152,728.9

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED:						
Developed Producing	1,494.0	1,214.3	-	-	-	-
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	4,213.1	3,458.9	-	-	-	-
TOTAL PROVED	5,707.1	4,673.2	-	-	-	-
PROBABLE	6,000.7	4,881.6	-	-	-	-
TOTAL PROVED PLUS PROBABLE	11,707.8	9,554.8	-	-	-	-

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	311.6	253.5	1,545.9	1,256.6
Developed Non-Producing	-	-	-	-
Undeveloped	2,190.9	1,784.8	4,578.3	3,756.3
TOTAL PROVED	2,502.5	2,038.3	6,124.2	5,012.9
PROBABLE	3,045.2	2,470.6	6,508.2	5,293.4
TOTAL PROVED PLUS PROBABLE	5,547.7	4,508.9	12,632.4	10,306.3

TOTAL

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED:						
Developed Producing	6,078.2	4,587.6	31,357.7	25,997.0	1,989.3	1,450.3
Developed Non-Producing	487.4	368.6	16,333.8	13,782.6	515.9	373.7
Undeveloped	8,002.4	6,272.5	49,363.0	41,952.9	312.9	225.5
TOTAL PROVED	14,568.0	11,228.7	97,054.5	81,732.5	2,818.1	2,049.5
PROBABLE	10,233.0	7,846.4	48,542.3	40,959.7	1,500.2	1,083.6
TOTAL PROVED PLUS PROBABLE	24,801.0	19,075.1	145,596.8	122,692.2	4,318.3	3,133.1

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	68,546.0	57,493.9	50,849.5	41,617.3
Developed Non-Producing	11,780.3	8,882.0	19,300.5	16,005.2
Undeveloped	9,331.2	7,417.6	59,233.6	49,687.1
TOTAL PROVED	89,657.5	73,793.5	129,383.6	107,309.6
PROBABLE	44,089.7	35,014.4	67,623.8	55,725.6
TOTAL PROVED PLUS PROBABLE	133,747.2	108,808.9	197,007.4	163,035.2

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
CANADA					
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,697,967	1,420,066	1,239,572	1,111,355	1,014,538
Developed Non-Producing	711,236	539,201	423,496	341,880	282,129
Undeveloped	1,913,199	1,332,078	982,376	759,303	607,675
TOTAL PROVED	4,322,402	3,291,345	2,645,444	2,212,538	1,904,342
PROBABLE	2,175,593	1,437,071	1,037,388	791,887	628,486
TOTAL PROVED PLUS PROBABLE	6,497,995	4,728,416	3,682,832	3,004,425	2,532,828
UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	81,938	53,211	39,465	31,667	26,688
Developed Non-Producing	-	-	-	-	-
Undeveloped	205,350	97,852	50,284	25,660	11,420
TOTAL PROVED	287,288	151,063	89,749	57,327	38,108
PROBABLE	420,363	140,138	60,386	28,926	13,403
TOTAL PROVED PLUS PROBABLE	707,651	291,201	150,135	86,253	51,511
TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	1,779,905	1,473,277	1,279,037	1,143,022	1,041,226
Developed Non-Producing	711,236	539,201	423,496	341,880	282,129
Undeveloped	2,118,549	1,429,930	1,032,660	784,963	619,095
TOTAL PROVED	4,609,690	3,442,408	2,735,193	2,269,865	1,942,450
PROBABLE	2,595,956	1,577,209	1,097,774	820,813	641,889
TOTAL PROVED PLUS PROBABLE	7,205,646	5,019,617	3,832,967	3,090,678	2,584,339

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
CANADA					
PROVED:					
Developed Producing	1,694,844	1,418,963	1,239,160	1,111,193	1,014,472
Developed Non-Producing	518,211	405,456	327,172	270,377	227,750
Undeveloped	1,395,954	971,514	713,403	549,064	437,859
TOTAL PROVED	3,609,009	2,795,933	2,279,735	1,930,634	1,680,081
PROBABLE	1,612,560	1,057,570	760,701	579,778	460,111
TOTAL PROVED PLUS PROBABLE	5,221,569	3,853,503	3,040,436	2,510,412	2,140,192
UNITED STATES					
PROVED:					
Developed Producing	81,938	53,211	39,465	31,667	26,688
Developed Non-Producing	-	-	-	-	-
Undeveloped	154,745	80,225	43,450	22,782	10,124
TOTAL PROVED	236,683	133,436	82,915	54,449	36,812
PROBABLE	244,771	83,387	36,626	17,317	7,180
TOTAL PROVED PLUS PROBABLE	481,454	216,823	119,541	71,766	43,992
TOTAL					
PROVED:					
Developed Producing	1,776,782	1,472,174	1,278,625	1,142,860	1,041,160
Developed Non-Producing	518,211	405,456	327,172	270,377	227,750
Undeveloped	1,550,699	1,051,739	756,853	571,846	447,983
TOTAL PROVED	3,845,692	2,929,369	2,362,650	1,985,083	1,716,893
PROBABLE	1,857,331	1,140,957	797,327	597,095	467,291
TOTAL PROVED PLUS PROBABLE	5,703,023	4,070,326	3,159,977	2,582,178	2,184,184

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

TOTAL PROVED RESERVES	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	WELL ABANDONMENT COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Canada	8,875,682	1,407,196	2,450,816	538,340	156,928	4,322,402	713,392	3,609,010
United States	655,768	201,997	89,158	77,325	-	287,288	50,606	236,682
Total	9,531,450	1,609,193	2,539,974	615,665	156,928	4,609,690	763,998	3,845,692
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	13,522,570	2,167,032	3,926,742	738,303	192,496	6,497,997	1,276,425	5,221,572
United States	1,522,810	470,564	212,227	132,369	-	707,650	226,198	481,452
Total	15,045,380	2,637,596	4,138,969	870,672	192,496	7,205,647	1,502,623	5,703,024

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2009
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/boe) (1)
CANADA			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	194,223	26.52
	Heavy Oil (including solution gas and other by-products)	2,170,804	26.46
	Natural Gas (including by-products but excluding natural gas from oil wells)	280,417	21.66
	Total Canada	2,645,444	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	275,270	25.83
	Heavy Oil (including solution gas and other by-products)	3,008,370	24.44
	Natural Gas (including by-products but excluding natural gas from oil wells)	399,192	21.06
	Total Canada	3,682,832	
UNITED STATES			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	89,749	17.90
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total United States	89,749	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	150,135	14.57
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total United States	150,135	
TOTAL			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	283,972	23.02
	Heavy Oil (including solution gas and other by-products)	2,170,804	26.46
	Natural Gas (including by-products but excluding natural gas from oil wells)	280,417	21.66
	Total	2,735,193	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	425,406	20.29
	Heavy Oil (including solution gas and other by-products)	3,008,370	24.44
	Natural Gas (including by-products but excluding natural gas from oil wells)	399,192	21.06
	Total	3,832,968	

Note:

(1) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth above under the subheading "*Disclosure of Reserves Data*" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**Gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

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

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**Net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

   (c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

   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

   (a) analysis of drilling, geological, geophysical and engineering data;

   (b) the use of established technology; and

   (c) specified economic conditions (see the discussion of "*Economic Assumptions*" below).

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

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

   (c) "Economic Assumptions" will be the forecast prices and costs used in the estimate.

   Development and Production Status

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

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

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) 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.

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:

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

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

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. "**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

5. "**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

6. "**Development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

7. "**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

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

9. "**Forecast Prices and Costs**"

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which Baytex is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

10. Numbers may not add due to rounding.

11. The estimates of future net revenue presented in the tables above do not represent fair market value.

12. This year we have reported the estimates of our bitumen reserves with our heavy oil reserves. As the volume of bitumen reserves is relatively small compared to our volume of heavy oil reserves, this inclusion is permitted under NI 51-101 and the COGE Handbook. This reporting is consistent in all of the reserves disclosure in this Annual Information Form.

As of December 31, 2009, Sproule attributed gross probable undeveloped bitumen reserves of 8,196.3 Mbbl to our permanent steam project at Seal, Alberta. By comparison, as of December 31, 2008, Sproule attributed gross probable undeveloped bitumen reserves of 2,463.7 Mbbl to our permanent steam project at Seal, Alberta. Sproule did not attribute any other bitumen reserves in any other category or any other area this year or last. After deducting the volumes of probable undeveloped bitumen reserves, Sproule's estimates of our total proved plus probable heavy oil reserves were 137,400.5 Mbbl as of December 31, 2009, and 123,589.8 Mbbl as of December 31, 2008.

13. On March 11, 2010, the Alberta government announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the oil and natural gas industry, which included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011 production month and certain temporary incentive programs currently in place being made permanent. See "*Industry Conditions*". Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months. Reserves and net present values reflected in the above tables do not reflect the potential effect of these new changes to Alberta's royalty system and no sensitivities were provided by Sproule as to the potential impact of same.

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2009, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2009

	OIL			NATURAL GAS		
	WTI Cushing Oklahoma ($US/bbl)	**Edmonton Par Price 40° API ($Cdn/bbl)**	**Hardisty Heavy 12° API ($Cdn/bbl)**	**AECO-C ($Cdn/MMbtu)**	**INFLATION RATES (1) %/year**	**EXCHANGE RATE (2) ($US/$Cdn)**
Historical						
2005	56.46	69.29	34.35	8.58	1.3	0.826
2006	66.09	73.30	43.32	7.16	1.5	0.882
2007	72.27	77.06	44.77	6.65	2.0	0.935
2008	99.59	102.85	76.32	8.15	1.0	0.943
2009 Est.	61.63	66.20	55.59	4.19	2.0	0.880
Forecast						
2010	79.17	84.25	69.93	5.36	2.0	0.920
2011	84.46	89.99	73.79	6.21	2.0	0.920
2012	86.89	92.61	74.08	6.44	2.0	0.920
2013	90.20	96.19	75.03	7.23	2.0	0.920
2014	92.01	98.13	74.58	7.98	2.0	0.920
Thereafter.			Various escalation rates			

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average prices realized by us for the year ended December 31, 2009, excluding hedging activities, were $4.35/Mcf for natural gas, $54.25/bbl for light oil and NGL and $49.88/bbl for heavy oil.

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
CANADA	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2008	11,081.9	5,461.8	16,543.7	86,936.9	39,116.6	126,053.5
Extensions	37.9	155.5	193.4	7,553.6	6,138.3	13,691.9
Improved Recovery	914.0	506.9	1,420.9	6,412.0	4,666.7	11,078.7
Technical Revisions	(1,742.4)	(2,020.4)	(3,762.8)	(120.5)	(2,740.6)	(2,861.1)
Discoveries	83.3	103.6	186.9	83.9	32.0	115.9
Acquisitions	85.4	21.4	106.8	5,122.0	1,348.4	6,470.4
Dispositions	-	-	-	(6.6)	(5.8)	(12.4)
Economic Factors	19.9	3.5	23.4	80.6	(13.3)	67.3
Production	(1,619.1)	-	(1,619.1)	(9,007.5)	-	(9,007.5)
December 31, 2009	8,860.9	4,232.3	13,093.2	97,054.4	48,542.3	145,596.7

	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS			NATURAL GAS LIQUIDS		
CANADA	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2008	117,960.0	55,016.0	172,976.0	3,725.5	1,846.3	5,571.8
Extensions	36.0	2,021.0	2,057.0	1.2	77.8	79.0
Improved Recovery	1,329.0	920.0	2,249.0	37.3	33.5	70.8
Technical Revisions	(14,456.0)	(18,873.0)	(33,329.0)	(281.8)	(509.7)	(791.5)
Discoveries	795.0	405.0	1,200.0	32.9	16.4	49.3
Acquisitions	5,599.0	1,817.0	7,416.0	114.5	33.2	147.7
Dispositions	(169.0)	(43.0)	(212.0)	-	-	-
Economic Factors	(2,686.0)	(218.0)	(2,904.0)	(43.2)	2.8	(40.4)
Production	(21,252.0)	-	(21,252.0)	(768.3)	-	(768.3)
December 31, 2009	87,156.0	41,045.0	128,201.0	2,818.1	1,500.3	4,318.4

	OIL EQUIVALENT		
CANADA	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2008	121,404.4	55,594.0	176,998.4
Extensions	7,598.7	6,708.4	14,307.1
Improved Recovery	7,584.8	5,360.4	12,945.2
Technical Revisions	(4,554.0)	(8,416.2)	(12,970.2)
Discoveries	332.6	219.5	552.1
Acquisitions	6,255.1	1,705.9	7,961.0
Dispositions	(34.8)	(13.0)	(47.8)
Economic Factors	(390.4)	(43.3)	(433.7)
Production	(14,936.9)	-	(14,936.9)
December 31, 2009	123,259.5	61,115.7	184,375.2

UNITED STATES	LIGHT AND MEDIUM OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2008	3,947.6	5,322.0	9,269.6	2,016.0	3,210.0	5,226.0
Extensions	1,022.1	1,904.7	2,926.8	399.0	979.0	1,378.0
Improved Recovery	-	-	-	-	-	-
Technical Revisions	880.7	(1,232.4)	(351.7)	111.0	(1,144.0)	(1,033.0)
Discoveries	-	-	-	-	-	-
Acquisitions	2.7	5.0	7.7	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(1.6)	1.4	(0.2)	-	-	-
Production	(144.4)	-	(144.4)	(23.0)	-	(23.0)
December 31, 2009	5,707.1	6,000.7	11,707.8	2,503.0	3,045.0	5,548.0

UNITED STATES	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2008	4,283.6	5,857.0	10,140.6
Extensions	1,088.6	2,067.9	3,156.5
Improved Recovery	-	-	-
Technical Revisions	899.2	(1,423.1)	(523.9)
Discoveries	-	-	-
Acquisitions	2.7	5.0	7.7
Dispositions	-	-	-
Economic Factors	(1.6)	1.4	(0.2)
Production	(148.2)	-	(148.2)
December 31, 2009	6,124.3	6,508.2	12,632.5

TOTAL	LIGHT AND MEDIUM OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	HEAVY OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2008	15,029.5	10,783.8	25,813.3	86,936.9	39,116.6	126,053.5
Extensions	1,060.0	2,060.2	3,120.2	7,553.6	6,138.3	13,691.9
Improved Recovery	914.0	506.9	1,420.9	6,412.0	4,666.7	11,078.7
Technical Revisions	(861.7)	(3,252.8)	(4,114.5)	(120.5)	(2,740.6)	(2,861.1)
Discoveries	83.3	103.6	186.9	83.9	32.0	115.9
Acquisitions	88.1	26.4	114.5	5,122.0	1,348.4	6,470.4
Dispositions	-	-	-	(6.6)	(5.8)	(12.4)
Economic Factors	18.3	4.9	23.2	80.6	(13.3)	67.3
Production	(1,763.5)	-	(1,763.5)	(9,007.5)	-	(9,007.5)
December 31, 2009	14,568.0	10,233.0	24,801.0	97,054.4	48,542.3	145,596.7

TOTAL	Associated, Non-Associated and Solution Gas Proved (MMcf)	Associated, Non-Associated and Solution Gas Probable (MMcf)	Associated, Non-Associated and Solution Gas Proved Plus Probable (MMcf)	Natural Gas Liquids Proved (MMcf)	Natural Gas Liquids Probable (MMcf)	Natural Gas Liquids Proved Plus Probable (MMcf)
December 31, 2008	119,976.0	58,226.0	178,202.0	3,725.5	1,846.3	5,571.8
Extensions	435.0	3,000.0	3,435.0	1.2	77.8	79.0
Improved Recovery	1,329.0	920.0	2,249.0	37.3	33.5	70.8
Technical Revisions	(14,345.0)	(20,017.0)	(34,362.0)	(281.8)	(509.7)	(791.5)
Discoveries	795.0	405.0	1,200.0	32.9	16.4	49.3
Acquisitions	5,599.0	1,817.0	7,416.0	114.5	33.2	147.7
Dispositions	(169.0)	(43.0)	(212.0)	-	-	-
Economic Factors	(2,686.0)	(218.0)	(2,904.0)	(43.2)	2.8	(40.4)
Production	(21,275.0)	-	(21,275.0)	(768.3)	-	(768.3)
December 31, 2009	89,659.0	44,090.0	133,749.0	2,818.1	1,500.3	4,318.4

TOTAL	Oil Equivalent Proved (Mboe)	Oil Equivalent Probable (Mboe)	Oil Equivalent Proved Plus Probable (Mboe)
December 31, 2008	125,688.0	61,451.0	187,139.0
Extensions	8,687.3	8,776.3	17,463.6
Improved Recovery	7,584.8	5,360.4	12,945.2
Technical Revisions	(3,654.8)	(9,839.3)	(13,494.1)
Discoveries	332.6	219.5	552.1
Acquisitions	6,257.8	1,710.9	7,968.7
Dispositions	(34.8)	(13.0)	(47.8)
Economic Factors	(392.0)	(41.9)	(433.9)
Production	(15,085.1)	-	(15,085.1)
December 31, 2009	129,383.8	67,623.9	197,007.7

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by Sproule in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Approximately 50 to 60 percent of our expected funds from operations are available for capital expenditures related to exploration and development activities and the balance is distributed to our Unitholders. We allocate development capital to our assets in an efficient and disciplined process. We reduce risk by technically assessing the results of each of our development programs before committing additional capital. This disciplined approach to investing in development means that in most cases it will take longer than two years to develop our proved undeveloped and probable undeveloped reserves. We plan to develop the majority of our proved undeveloped reserves and probable undeveloped reserves over the next six years.

Our capital spending on development projects is budgeted annually for each of our business units. Once a development program is executed, we measure and analyze the results of that capital investment, make any changes to the program that are necessary, and then repeat the process until all economic oil and gas reserves are developed. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil Gross (Mbbl)		**Heavy Oil Gross (Mbbl)**		**NGLs Gross (Mbbl)**		**Natural Gas Gross (MMcf)**	
Year	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**
Prior	1,966.6	4,921.8	36,545.6	78,705.9	832.9	1,629.6	20,069.1	44,292.8
2007	2,112.0	3,574.1	9,833.3	38,168.8	55.6	378.4	2,559.0	15,587.0
2008	2,830.6	6,234.1	2,175.9	37,584.1	37.3	375.4	3,234.0	15,446.0
2009	1,874.4	8,002.4	18,084.9	49,363.0	106.1	312.9	3,123.0	9,331.0

Sproule assigned a total of 482 well locations to the proved undeveloped reserve category, of which 394 are located on our Canadian heavy oil producing properties. The 394 heavy oil proved undeveloped locations are scheduled to be drilled over the next six years. Sixty-nine of the total proved undeveloped locations are within our Canadian conventional oil and gas producing properties. These conventional oil and gas well locations are scheduled to be drilled over the next five years. The remaining 19 proved undeveloped wells are located in the United States within Divide County, North Dakota. This is a conventional, light oil development project area for Baytex. The wells in North Dakota are scheduled to be drilled over the next four years.

It would not be prudent from both a financial and technical perspective for us to develop all of our proved undeveloped reserves over the next two years. Our operating budget allocates between 50 to 60 percent of expected funds from operations to exploration and development activities. This restricts the number of development wells we drill in any given year to approximately 90 net wells based on 2009 spending and activity levels. Not all of the development wells that we drill in any given year are contained within the Sproule defined proved undeveloped inventory. At our current pace of investment and drilling it will take approximately six years to develop all the currently identified proved undeveloped reserves in the Sproule Report.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

	Light and Medium Oil Gross (Mbbl)		**Heavy Oil Gross (Mbbl)**		**NGLs Gross (Mbbl)**		**Natural Gas Gross (MMcf)**	
Year	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**
Prior	694.9	1,721.6	19,117.0	42,565.2	671.2	972.4	14,150.0	26,529.1
2007	1,040.8	1,557.5	3,804.1	20,410.1	513.3	615.7	5,476.0	10,832.0
2008	5,179.3	6,404.7	7,296.9	23,098.4	76.3	362.2	5,467.0	13,587.0
2009	3,457.1	7,518.2	19,426.4	31,494.5	135.4	368.2	4,444.0	11,210.0

Sproule assigned a total of 176 well locations to the probable undeveloped reserve category, of which 149 are located within our Canadian primary heavy oil producing properties. The majority of these 149 heavy oil locations are scheduled to be drilled over the next six years. Forty of these probable undeveloped locations are thermal heavy oil wells located in the Seal area of Alberta. Sproule has scheduled these thermal wells to be drilled by the end of 2014. Thirteen of these probable undeveloped locations are located on our Canadian conventional oil and gas producing properties. These conventional oil and gas locations are scheduled to be drilled over the next five years. The remaining 14 probable undeveloped wells are located in the United States within Divide County, North Dakota.

This is a conventional light oil development project area for Baytex. These wells in North Dakota are scheduled to be drilled over the next four years.

For the same reasons given above, we will not develop all of our probable undeveloped reserves over the next two years. Our operating budget allocates between 50 to 60 percent of our expected funds from operations to exploration and development activities. This restricts the number of development wells we drill in any given year to approximately 90 net wells based on 2009 spending and activity levels. Not all of the development wells that we drill in any given year are contained within the Sproule defined proved undeveloped or probable undeveloped inventory. At our current pace of investment and drilling it will take approximately six years to develop all the currently identified probable undeveloped reserves.

Significant Factors or Uncertainties

We have a significant amount of proved non-producing and proved undeveloped reserves assigned to our Canadian heavy oil properties located in the Province of Saskatchewan and at our Seal, Ardmore and Cold Lake heavy oil properties located in the Province of Alberta. Our conventional light oil and gas properties in Stoddart, British Columbia, the Pembina and Ferrier areas of Alberta and Divide County, North Dakota, USA also contain a significant quantity of proved non-producing and proved undeveloped reserves. As well, we have a significant amount of probable non-producing and probable undeveloped reserves assigned to these same properties. At the current prices, these development activities are economic. However, should oil and natural gas prices fall materially, these activities may not be economic and we could defer their implementation. In addition, reserves can be affected significantly by fluctuations in capital expenditures, operating costs, royalty regimes, and well performance that are beyond our control and which could impact our development decisions. See also "*Risk Factors*".

Future Development Costs

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

	FORECAST PRICES AND COSTS	
YEAR	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
	CANADA	
2010	83,661	94,114
2011	126,873	147,839
2012	115,573	141,981
2013	50,644	91,565
2014	36,916	93,289
Remaining	124,673	169,515
Total (Undiscounted)	538,340	738,303
	UNITED STATES	
2010	18,822	31,122
2011	35,439	65,018
2012	18,695	28,691
2013	4,369	7,538
2014	-	-
Remaining	-	-
Total (Undiscounted)	77,325	132,369
	TOTAL	
2010	102,483	125,236
2011	162,312	212,857
2012	134,268	170,672
2013	55,013	99,103
2014	36,916	93,289
Remaining	124,673	169,515
Total (Undiscounted)	615,665	870,672

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity financings. Our operating budget allocates between 50 to 60 percent of our expected funds from operations to exploration and development activities.

There can be no guarantee that funds will be available or that our Board of Directors will allocate funding to develop all of the reserves attributed in the Sproule Report. Failure to develop those reserves could have a negative impact on our future cash flow.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth herein and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of these properties uneconomic.

Other Oil and Gas Information

Oil and Natural Gas Properties

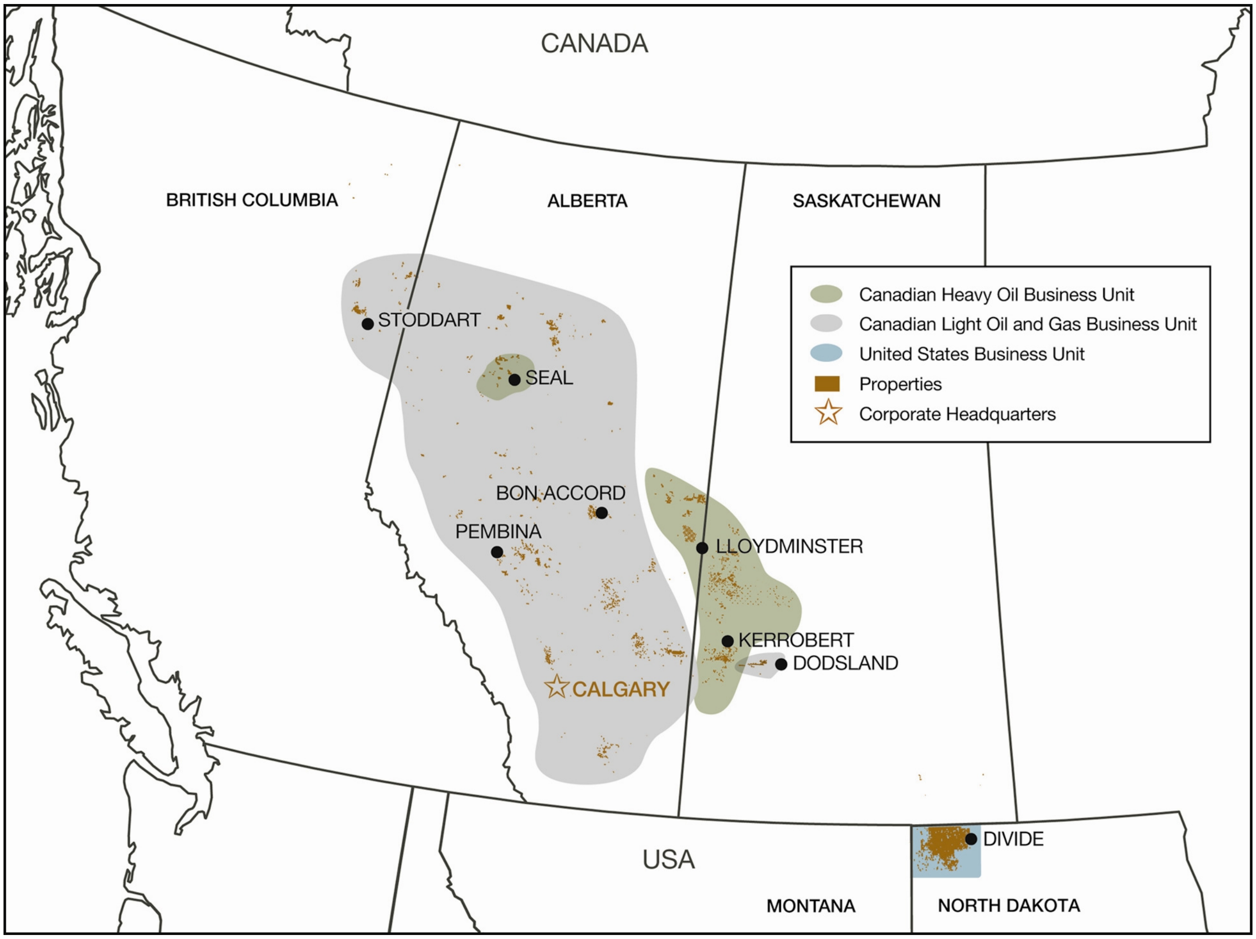
The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2009. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2009. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2009, except where otherwise indicated.

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Light Oil and Gas and United States business units. Each business unit has a portfolio of operated properties and development prospects with upside potential. Within these business units, Baytex has established a total of eight geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

Baytex invested approximately $103 million in undeveloped land over the past two years targeting three light oil resource plays. These plays include the Bakken/Three Forks in the Williston Basin of North Dakota, the Viking in southwestern Saskatchewan and eastern Alberta and a Mowry Shale exploratory play in the Powder River Basin of eastern Wyoming. These light oil resource plays provide the opportunity for long term light oil production and reserve growth to complement our heavy oil growth projects. These resource plays are described in more detail in the business unit descriptions below.

The map below highlights the geographic location of our principal properties.

Baytex Energy Trust – Principal Properties



Canadian Heavy Oil Business Unit

The Canadian Heavy Oil Business Unit accounts for more than 60% of current production and more than 70% of oil-equivalent reserves. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 500 bbl/d of crude with gravities ranging from 11 to 18 degrees API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with light-hydrocarbon diluents (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2009, production in the Canadian Heavy Oil Business Unit averaged approximately 25,913 boe/d, which was comprised of 24,678 bbl/d of heavy oil and 7,409 Mcf/d of natural gas. During 2009, Baytex drilled 90 (82.3 net) wells in the Canadian Heavy Oil Business Unit resulting in 83 (76.3 net) oil wells, 2 (2.0 net) stratigraphic test wells, 2 (1.0 net) service wells, and 3 (3.0 net) dry and abandoned wells, for a success rate of 97% (96% net).

The Canadian Heavy Oil Business Unit possesses a large inventory of development projects within the operating areas of west-central Saskatchewan and Cold Lake/Ardmore and Peace River in Alberta. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining our overall production rate. Due to the size of inventory of heavy oil projects, we are able to select from a wide range of investment opportunities to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area and Baytex's historical area of emphasis around Lloydminster. Our net undeveloped lands in the Canadian Heavy Oil Business Unit totalled approximately 382,000 acres at year-end 2009.

Listed below is a brief description of the principal properties within the Canadian Heavy Oil Business Unit:

<u>Ardmore, Alberta</u>: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2009 was approximately 1,012 bbl/d of oil and 374 Mcf/d of natural gas (1,074 boe/d). Two successful oil wells were drilled in the area during 2009. Baytex anticipates drilling one well in this area in 2010. Net undeveloped lands were 39,000 acres at year-end 2009.

<u>Carruthers, Saskatchewan</u>: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. Five new wells were drilled in 2009 which, combined with relatively low production declines due mostly to strong performance of the ongoing waterflood, led to a year-over-year production increase. The waterflood was expanded in 2009 and Baytex plans to further expand the waterflood area in 2010. We plan to drill 16 wells in the Carruthers area in 2010. Average production in 2009 was approximately 2,164 bbl/d of heavy oil and 583 Mcf/d of natural gas (2,261 boe/d). Net undeveloped lands were 12,600 acres at year-end 2009.

<u>Celtic, Saskatchewan</u>: This producing property was acquired in October 2005, in a transaction where Baytex purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, production averaged 4,326 bbl/d of heavy oil and 878 Mcf/d of natural gas (4,472 boe/d) during 2009. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. The heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2010, Baytex expects to drill 7 new wells and re-complete approximately 20 existing wells. Net undeveloped lands were 8,700 acres at year-end 2009.

<u>Cold Lake, Alberta</u>: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2009 was approximately 476 bbl/d. Baytex drilled five successful oil wells in the Cold Lake area in 2009, and we plan to drill one new well in the area in 2010. Net undeveloped lands were 13,600 acres at year-end 2009.

<u>Dodsland, Saskatchewan:</u> During 2008, Baytex developed a new resource play in the Viking sand in southwest Saskatchewan. The zone is regionally charged with light (34 degrees API) oil, and in its more permeable areas, has been a prolific oil horizon since the 1960s. Baytex targeted the less permeable but undeveloped areas of the play and drilled a 1,400 metre horizontal well in 2008. The horizontal well was completed with 7 fracture stimulations, applying the same multi-zone fracture technology that is used to stimulate horizontal wells in the Bakken oil play in southeast Saskatchewan and North Dakota. Production performance from the first Dodsland Viking well was encouraging and Baytex intends to drill several additional horizontal Viking tests in 2010. At year-end 2009, Baytex had leased 34,500 net acres in the play. Ultimately, more than 150 wells may be drilled on these lands.

<u>Kerrobert/Coleville, Saskatchewan:</u> Baytex acquired assets in the Kerrobert and Coleville areas of Saskatchewan on July 30, 2009. The acquisition provides numerous opportunities for cold infill drilling and steam-assisted gravity drainage (SAGD) optimization. In addition, the Kerrobert area offers significant potential for light oil development in the Viking formation using horizontal wells with multi-stage hydraulic fractures, similar to the Dodsland Viking opportunities described above. Baytex also holds a 50% non-operated interest in a pilot project in the Kerrobert area using toe-to-heel air injection in horizontal wells. At the time of the acquisition, the acquired assets produced

approximately 3,000 boe/d. Baytex drilled two (1.0 net) oil wells and two (1.0 net) service wells in this area in 2009, and performed workovers on several wells. Baytex plans to drill 9 wells in this area in 2010. Net undeveloped lands were 50,135 acres at year-and 2009.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June 2007. Baytex has a 21.25% working interest in this property, which is operated by a senior Canadian producer. Average production in this area during 2009 was approximately 577 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. Seven (1.5 net) wells were drilled in this area in 2009. Net undeveloped lands were 1,400 acres at year-end 2009.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 degrees API. Initial per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2009 was approximately 3,270 bbl/d of oil and 409 Mcf/d of natural gas (3,338 boe/d). Seven (7.0 net) successful oil wells and two (2.0 net) dry holes were drilled in this region in 2009. For 2010, a further 10 wells are planned. Net undeveloped lands were 24,000 acres at year-end 2009.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in 105 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced using horizontal wells at initial production rates of 150 to 500 bbl/d per well, without employing more cost-intensive methods such as steam injection. In 2009, Baytex drilled two stratigraphic test wells, designed to identify extensions to our current development areas. Baytex also drilled 17 horizontal production wells in 2009, bringing the total number of producing wells to 61. The average production rate during 2009 was 5,095 bbl/d of heavy oil. Reservoir analysis of the Seal property has indicated that both waterflood and cyclic steam recovery methods have the potential to increase economic oil reserves beyond what is achievable with cold primary recovery. A cyclic steam pilot project was carried out on an existing horizontal producer during 2008 to validate the numerical reservoir simulation models. Based on our successful pilot, we are conducting the remaining design activities and reservoir modeling to install a permanent steam project, with start-up targeted for late 2011. As the region continues to develop, the Seal property will take an increasingly more prominent role in our production profile. During 2010, Baytex plans to drill six stratigraphic test wells, 20 cold horizontal production wells, and we intend to re-enter several existing single-leg horizontal wells and drill additional legs at closer inter-well spacing to increase recovery from these older wells. Net undeveloped lands were 63,000 acres at year-end 2009.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. In 2009, Baytex drilled 8 (8.0 net) wells in the area. We plan to drill approximately 17 wells in the area in 2010. Average production during 2009 was approximately 2,062 bbl/d of heavy oil and 683 Mcf/d of natural gas (2,176 boe/d). Net undeveloped lands were 7,800 acres at year-end 2009.

Canadian Light Oil and Gas Business Unit

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties. In addition to Baytex's historical light oil and natural gas properties in northern and south-eastern Alberta, the geographic scope of our conventional oil and gas operations has expanded to central Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Canadian Light Oil and Gas Business Unit produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. During 2009, production from this business unit averaged 15,063 boe/d, which was comprised of 51.1 MMcf/d of natural gas sales and 6,540 bbl/d of light oil and NGL. During 2009, the Canadian Light Oil and Gas Business Unit drilled 16 (14.5 net) wells resulting in 5 (3.5 net) gas wells, 10 (10.0 net) oil wells, and 1 (1.0 net) dry hole for a success rate of 94% (93% net). Our net undeveloped lands in this business unit were approximately 289,000 acres at year-end 2009.

Listed below is a brief description of the principal properties within the Canadian Light Oil and Gas Business Unit:

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2009, production for the area averaged approximately 2,073 Mcf/d of gas and 304 bbl/d of light oil (650 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. In the past two years, Baytex has worked to exploit the Viking sand utilizing horizontal drilling technology. During 2009, Baytex drilled three (3.0 net) horizontal Viking oil wells in this area, and we plan to drill up to six horizontal Viking oil wells in the area in 2010. At year-end 2009, Baytex had 8,700 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2009 averaged approximately 1,844 Mcf/d of gas (307 boe/d). At year-end 2009, Baytex had 13,400 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 3,705 Mcf/d of gas and 13 bbl/d of NGL (631 boe/d) during 2009 from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. During 2009, Baytex drilled one (1.0 net) dry hole in the area. At year-end 2009, Baytex had 8,300 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its initial position in Pembina in June 2007 and further expanded its presence in the area through the acquisition of Burmis in June 2008. Production is primarily from the Nisku formation and to a lesser extent from Cretaceous and Jurassic age formations including the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at two third-party oil batteries. Gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the producer-operated gas processing facilities and a minor working interest in one of the mid-stream gas processing facilities. During 2009, Pembina production averaged 3,547 bbl/d of light oil and NGL and 21,170 Mcf/d of gas (7,075 boe/d). Baytex participated in drilling 6 (5.7 net) operated and 2 (0.8 net) non-operated locations in 2009. Two wells (2.0 net) were drilled to test Nisku prospects, resulting in 2 (2.0 net) oil wells. Four (2.5 net) wells were drilled for development of multi-zone potential in the Cretaceous in 2009, resulting in 4 (2.5 net) gas wells. Two Cardium horizontal wells (2.0 net) were successfully drilled and completed with multi-stage fracture stimulations resulting in 2 (2.0 net) oil wells. During the first quarter of 2009, Baytex constructed a pipeline in the O'Chiese area which facilitated an increase in gas production and improved netback prices. The 2010 drilling program for Pembina is planned to include up to five additional Cardium oil tests, two wells to evaluate Nisku prospects, and four wells for multi-zone Cretaceous potential. At year-end 2009, Baytex had 28,000 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: Baytex acquired its initial position in this area in 2001, and significantly increased its presence with a 2004 acquisition of a private company. During 2009, production averaged approximately 5,400 Mcf/d of sales gas and 11 bbl/d of NGL (911 boe/d). This area has year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas produced from this area is processed at two Baytex-operated gas plants. During 2009, Baytex drilled 1 (1.0 net) successful gas well in this area. At year-end 2009, Baytex had 27,500 net undeveloped acres in this area.

Red Earth/Goodfish/Lafond, Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Baytex-operated. Production from this area during 2009 averaged approximately 3,191 Mcf/d of gas and 703 bbl/d of light oil and NGL (1,235 boe/d). Baytex did not drill any wells in this area in 2009, but we plan to drill one well in the area in 2010. At year-end 2009, Baytex had 28,200 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2009 averaged approximately 6,899 Mcf/d of gas and 1,122 bbl/d of oil and NGL (2,272 boe/d). Baytex drilled 2 (2.0 net) successful oil wells in 2009. We plan to drill one well in the area in 2010. At year-end 2009, Baytex had 27,500 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2009 averaged approximately 476 bbl/d of oil and NGL and 1,147 Mcf/d of gas (667 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. Baytex did not drill any wells in this area in 2009, but we plan to drill one well in this area in 2010. At year-end 2009, Baytex had 9,400 net undeveloped acres in this area.

United States Business Unit

Through our wholly-owned subsidiary, Baytex USA, we acquired significant land positions in the Williston and Powder River Basins in 2007 and 2008. During 2009, Baytex USA drilled 7 (2.2 net) wells and increased its acreage position to over 126,100 net acres. Net production from the United States properties averaged 408 boe/d in 2009, as compared to 188 boe/d in 2008. Development activity ramped up in the second half of 2009, and net production reached approximately 600 boe/d in December, 2009.

Listed below is a brief description of the principal properties within the United States Business Unit:

Williston Basin – Bakken/Three Forks Project: This light oil resource play is located in the Divide and Burke Counties of North Dakota. Production is primarily from horizontal wells using multi-zone hydraulic fracturing in the Bakken and Three Forks formations. Both zones are accessed through a single horizontal lateral. Baytex USA has invested in approximately 251,000 (94,000 net) acres of land, of which 230,632 (88,127 net) acres were undeveloped at year-end 2009. In 2009, Baytex USA participated in 6 (1.6 net) wells. Net production from the project averaged approximately 354 boe/d in 2009. In 2010, Baytex USA plans to drill approximately 20 (7.5 net) horizontal wells. Ultimately, the project has the potential to include 150 to 300 wells with average initial production rates expected to be approximately 300 boe/d per well and average recoveries expected to be approximately 275 Mboe/well.

Powder River Basin – Mowry Shale Play (Wild West): In September 2007, Baytex USA acquired its initial leasehold interest in this Mowry shale play in Wyoming covering approximately 15,300 (9,200 net) acres. A vertical well (Baytex USA 60% working interest) was drilled in 2008 to acquire core and ultimately serve as a microseismic monitoring well for subsequent horizontal-well fracturing. Completion of the vertical well, including hydraulic fracturing, was conducted in the first quarter of 2009. We drilled and completed our first horizontal well in the second half of 2009.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2009.

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canadian Heavy Oil Business Unit				
Ardmore	-	1,012	374	1,074
Carruthers	-	2,164	583	2,261
Celtic	-	4,326	878	4,472
Cold Lake	-	476	-	476
Golden lake	-	783	-	783
Greenstreet	-	42	1,059	219
Hoosier	-	445	-	445
Kerrobert / Coleville[1]		914	1,755	1,207
Lashburn	-	48	-	48
Lindbergh	-	577	61	587
Maidstone	-	852	-	852

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Marsden	-	584	-	584
Neilburg	-	498	-	498
Poundmaker	-	1,609	439	1,682
Seal	-	5,095	-	5,095
Silverdale / Epping / Macklin / Buzzard	-	2,686	409	2,754
Sugden	-	407	-	407
Tangleflags	-	2,062	683	2,176
Remaining properties	-	98	1,160	291
Total Canadian Heavy Oil Business Unit	-	24,678	7,401	25,911
Canadian Light Oil and Gas Business Unit				
Bon Accord	304	-	2,073	650
Darwin/Nina	-	-	1,844	307
Goodfish	-	-	2,633	439
Hamburg/Chinchaga	20	-	1,344	244
Leahurst	13	-	3,705	631
Pembina	3,547	-	21,170	7,075
Red Earth	703	-	558	796
Richdale / Sedalia	11	-	5,400	911
Stoddart	1,122	-	6,899	2,272
Tangent	-	-	320	53
Turin	476	-	1,147	667
Viking	-	-	853	142
Remaining Properties	344	-	3,193	876
Total Canadian Light Oil and Gas Business Unit	6,540	-	51,139	15,063
United States Business Unit				
Williston Basin	343	-	63	354
Powder River Basin	54	-	-	54
Total United States Business Unit	397	-	63	408
Grand Total	6,937	24,678	58,603	41,382

Note:

(1) The Kerrobert/Coleville properties were acquired on July 30, 2009. The production data in the table for these properties represents actual production for the period from July 30 to December 31, 2009 averaged over the entire year.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2009:

($000s)	Canada	United States	Total
Property acquisition costs (1)			
Proved properties	91,292	4,587	95,879
Unproved properties	8,035	42,677	50,712
Total Property acquisition costs	99,327	47,264	146,591
Development Costs (2)	119,359	12,419	131,778
Exploration Costs (3)	7,779	3,973	11,752
Total	226,465	63,656	290,121

Notes:

(1) Property acquisition costs include the property acquisition of Southwest Saskatchewan assets and are net of disposition of properties.

(2) Development and facilities expenditures.

(3) Cost of geological and geophysical capital expenditures and drilling costs for 2009 exploratory wells drilled.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2009.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	696	424.3	897	466.3	557	406.2	383	290.8
British Columbia	53	52.6	33	31.4	33	29.5	14	12.7
Saskatchewan	1,226	1,118.2	973	913.9	61	53.3	104	93.9
North Dakota	35	10.8	-	-	-	-	-	-
Wyoming	4	2.6	4	2.5	-	-	-	-
Total	2,014	1,608.5	1,907	1,414.1	651	489.0	501	397.4

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2009.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	535,093	399,875
British Columbia	78,500	52,870
Saskatchewan	241,090	217,568
Total Canada	854,683	670,313
United States		
New Mexico	14,313	14,313
North Dakota	230,632	88,127
Utah	1,140	578
Wyoming	41,635	23,087
Total United States	287,720	126,105
Grand Total	1,142,403	796,418

We expect that rights to explore, develop and exploit approximately 95,000 net acres of our undeveloped land holdings may expire on or before December 31, 2010. There are no material drilling commitments associated with the land holdings expiring by December 31, 2010.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2009.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	2	2.0	98	86.6
Natural Gas	4	2.4	1	1.0
Evaluation	2	2.0	0	0.0
Service	0	0.0	2	1.0
Dry	0	0.0	4	4.0
Total	8	6.4	105	92.6

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2009, see Note 18 to our annual audited financial statements as at and for the year ended December 31, 2009, which are incorporated herein by reference.

Tax Horizon

We are a taxable entity under the Tax Act and are taxable only on income that is not distributed or distributable to our Unitholders. We distribute all of our taxable income to our Unitholders and meet the requirements of the Tax Act applicable to us. As a result of our tax efficient structure, annual taxable income is currently transferred from our Operating Entities to the Trust and from the Trust to Unitholders. This is primarily accomplished through the deduction of the NPI payments and interest on the Notes.

Commencing in January 2011 (provided that we experience only "normal growth" and no "undue expansion" before then), we may be liable for tax at the federal "net corporate income tax rate" combined with the "provincial SIFT tax rate" (effectively, the federal general corporate tax rate plus the general provincial corporate income tax rate in each province in which the Trust has a permanent establishment) on all income payable to Unitholders, which we will not be able to deduct in computing our taxable income, as a result of being characterized as a SIFT trust. The effect of this new legislation is reflected in the after tax net revenue amounts disclosed in this Annual Information Form, other than the recently announced provincial SIFT tax rate.

For more information, see "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*", "*Risk Factors – Risks Relating to our Revenues – We may be impacted by recent federal tax changes for income trusts and corporations*" and "*Risk Factors – Risks Associated with Government Regulation – Our status as a mutual fund trust may be changed or affected by changes in legislation*".

Additional Information Concerning Abandonment and Reclamation Costs

The following table sets forth information respecting future abandonment and reclamation costs for surface leases, wells, facilities, and pipelines which are expected to be incurred by us for the periods indicated.

Period	**Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($ millions)**	**Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($ millions)**
Total liability as at December 31, 2009	279.28	40.62
Anticipated to be paid in 2010	1.23	1.18
Anticipated to be paid in 2011	1.28	1.14
Anticipated to be paid in 2012	7.39	6.11

We will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of the surface leases, wells, facilities, and pipelines held by us upon abandonment. Expenditures related to environmental obligations are expected to be funded out of cash flow.

We estimate the costs to abandon and reclaim all of our producing and shut in wells, facilities, and pipelines. In the table above, no estimate of salvage value is netted against the estimated cost. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

The number of net wells for which we estimated we will incur reclamation and abandonment costs is 4,673 wells. This estimate includes all producing wells, all non-producing wells, all standing cased wells and all suspended wells. The number of net wells for which Sproule estimated we will incur reclamation and abandonment costs is 658 wells which are all the proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2009. Abandonment and reclamation costs have been estimated over a 52-year period. Facility reclamation costs are scheduled to be incurred in the year following the end of the reserve life of its associated producing area. Only well abandonment costs, net of downhole salvage value were deducted by Sproule in estimating future net revenue in the Sproule Report. The additional liability associated with our existing wells, pipelines and facility reclamation costs, net of salvage, which was estimated to be $279.3 million ($40.6 million discounted at 10 percent), was not deducted in estimating future net revenue.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2009.

	($000s)
Exploration and Development	
Land	13,514
Seismic	2,222
Drilling and completion	113,959
Equipment	26,164
Other	1,185
Total exploration and development	157,044
Acquisitions (net of dispositions)	
Corporate acquisitions	-
Property acquisitions	133,155
Property dispositions	(78)
Total Acquisitions (net of dispositions)	133,077
Corporate Assets	7,050
Net capital expenditures	297,171

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2010, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Description of Our Business and Operations – Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data and Oil and Natural Gas Information*".

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas liquids (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA					
Total Proved	3,942	29,636	1,819	51,554	43,990
Total Proved plus Probable	4,381	31,456	2,019	56,626	47,294
UNITED STATES					
Total Proved	671	-	-	186	702
Total Proved plus Probable	700	-	-	201	733
TOTAL					
Total Proved	4,613	29,636	1,819	51,740	44,692
Total Proved plus Probable	5,081	31,456	2,019	56,827	48,027

No individual property accounts for 20% or more of the estimated production disclosed.

Production History

The following table summarizes certain information in respect of the production, product prices received, royalties paid, production costs and resulting netback associated with our reserves data for the periods indicated below.

	Three Months Ended				Year Ended
	Dec. 31, 2009	Sept 30, 2009	June 30, 2009	Mar. 31, 2009	Dec. 31, 2009
Average Daily Production (1)					
Light Oil and NGL (bbl/d) (2)	6,541	7,021	7,073	7,120	6,937
Heavy Oil (bbl/d)	26,423	25,532	23,284	23,432	24,678
Natural Gas (Mcf/d)	58,496	60,421	60,179	55,261	58,603
Total (boe/d)	42,713	42,623	40,387	39,762	41,382
Average Net Production Prices Received					
Light Oil and NGL($/bbl) (2)	62.68	57.50	54.28	43.05	54.25
Heavy Oil ($/bbl)	57.24	55.12	51.19	33.97	49.88
Natural Gas ($/Mcf)	4.87	3.42	3.85	5.39	4.35
Total ($/boe)	51.71	47.27	44.78	35.23	45.00
Royalties Paid					
Light Oil and NGL($/bbl) (2)	18.90	18.67	15.22	13.35	16.50
Heavy Oil ($/bbl)	11.78	11.44	9.89	4.30	9.52
Natural Gas ($/Mcf)	0.32	0.26	(0.42)	0.85	0.24
Total ($/boe)	10.21	10.30	7.75	6.13	8.67
Production Costs (3)(4)					
Light Oil and NGL($/bbl) (2)	13.15	9.32	12.82	12.71	11.98
Heavy Oil ($/bbl)	10.44	10.09	9.99	10.44	10.24
Natural Gas ($/Mcf)	2.07	1.94	1.73	1.88	1.92
Total ($/boe)	11.30	10.35	10.62	11.06	10.83
Transportation					
Light Oil and NGL($/bbl) (2)	0.28	0.25	0.29	0.20	0.26
Heavy Oil ($/bbl)	4.70	4.68	4.74	5.44	4.88
Natural Gas ($/Mcf)	0.17	0.14	0.14	0.15	0.20
Total ($/boe)	3.19	3.04	3.01	3.43	3.22
Netback Received (5)					
Light Oil and NGL($/bbl) (2)	30.35	29.26	25.95	16.79	25.51
Heavy Oil ($/bbl)	30.32	28.91	26.57	13.79	25.24
Natural Gas ($/Mcf)	2.31	1.08	2.40	2.51	1.99
Total ($/boe)	27.01	23.58	23.40	14.61	22.28
Financial Instruments gain(6) ($/boe)	3.78	5.21	5.55	7.10	5.36
Netback Received after hedging ($/boe)	30.79	28.79	28.95	21.71	27.64

Notes:
(1) Before deduction of royalties.
(2) Our NGL volumes are not material, and have been grouped with light oil for reporting purposes.
(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.
(4) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.
(5) Netbacks are calculated by subtracting royalties, operating costs, transportation and losses/gains on commodity and foreign exchange contracts from revenues.
(6) Financial instruments reflect only realized derivative gains (losses).

Marketing Arrangements

Baytex continues to market its oil and natural gas production with attention to maximizing value and counterparty performance. We maintain a portfolio of sales contracts with a variety of pricing mechanisms, term commitments, and customers. We engage a number of reputable counterparties in our bid process to ensure competitiveness, while also managing counterparty credit exposure.

Natural Gas

North American natural gas prices in 2009 were lower than in 2008, due to number of factors affecting both gas supply and demand. High on the list of supply factors was the growth in US gas production from shale plays, enabled by horizontal drilling and improving multi-stage fracturing technology. The resulting higher well productivity outweighed a significant decrease in the industry's gas drilling activity during 2009. At the same time, reduced demand for natural gas by commercial and industrial consumers contributed to high levels of gas-in-storage heading into winter. As a result, gas prices fell but then recovered in the fourth quarter of 2009, driven by increased demand created by prolonged and significantly cold weather over much of North America.

For 2009, Baytex's average physical gas sales price was $4.35/mcf, inclusive of physical forward sales contracts. This compares to a price of $7.92/mcf for 2008.

Oil and NGL

Oil prices in 2009 continued to be highly volatile. In January 2009, the prompt WTI benchmark oil price declined to US$33/bbl, driven by the effects of the global financial crisis. Over the course of the year, WTI prices rallied due to a number of factors, including rising demand from less-developed Asian economies (e.g., China) and an improving global economic outlook. WTI reached a 2009 peak spot price of US$82/bbl in October 2009, following an erratic but increasing price trend over the course of the year. The average WTI price in 2009 was US$61.80/bbl, compared to US$99.59/bbl in the prior year.

For 2009, Baytex's light oil and NGL prices averaged $54.25/bbl, while heavy oil sales prices averaged $49.88/bbl (inclusive of physical forward sales loss of $5.13/bbl). In contrast, for 2008 Baytex averaged $88.92/bbl for light oil and NGL and $65.22/bbl for heavy oil sales (net of physical forward sales losses of $7.62/bbl). These figures reflect the fact that while the benchmark WTI price was significantly higher in 2008, higher market demand for heavy crude in 2009 resulted in better relative value for Baytex's heavy oil production.

Environmental Policies

We have an active program to monitor and comply with all environmental laws, rules and regulations applicable to our operations. Our policies require that all employees and contractors report all breaches or potential breaches of environmental laws, rules and regulations to our senior management and all applicable governmental authorities. Any material breaches of environmental law, rules and regulations must be reported to the Board of Directors.

ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY TRUST

Trust Units

An unlimited number of Trust Units may be created and issued pursuant to the Trust Indenture. Each Trust Unit entitles the holder thereof to one vote at any meeting of the holders of Trust Units and represents an equal fractional undivided beneficial interest in any distribution from us (whether of net income, net realized capital gains or other amounts) and in any of our net assets in the event of our termination or winding-up. All Trust Units outstanding from time to time are entitled to an equal share of any distributions by us and, in the event of termination or winding-up of the Trust, in any of our net assets. All Trust Units rank among themselves equally and rateably without discrimination, preference or priority. Each Trust Unit is transferable, is not subject to any conversion or pre-emptive rights and entitles the holder thereof to require us to redeem any or all of the Trust Units held by such holder. See " – *Trust Indenture – Redemption Right*".

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in us or Baytex. Corporate law does not govern us and the rights of Unitholders. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the *Bankruptcy and Insolvency Act* (Canada) and the *Companies' Creditors Arrangement Act* (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation.

The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

A return on an investment in us is not comparable to the return on an investment in a fixed income security. The recovery of an initial investment in us is at risk, and the anticipated return on such investment is based on many performance assumptions. Although we intend to make cash distributions to holders of Trust Units, these cash distributions may be reduced or suspended. The actual amount distributed will depend on numerous factors including: the financial performance of Baytex, debt obligations, working capital requirements and future capital requirements. In addition, the market value of the Trust Units may decline if our cash distributions decline in the future and that market value decline may be material.

It is important for an investor to consider the particular risk factors that may affect the industry in which it is investing, and therefore the stability of the distributions that it receives. See "*Risk Factors*".

The after tax return from an investment in Trust Units to Unitholders subject to Canadian income tax can be made up of both a return on capital and a return of capital. That composition may change over time, thus affecting an investor's after tax return. Returns on capital are generally taxed as ordinary income in the hands of a Unitholder. Returns of capital are generally tax deferred (and reduce the Unitholder's cost base in the Trust Unit for tax purposes).

The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, we are not a trust company and, accordingly, are not registered under any trust and loan company legislation as we do not carry on or intend to carry on the business of a trust company.

Special Voting Units

In order to allow us flexibility in pursuing corporate acquisitions, the Trust Indenture allows for the creation of Special Voting Units which enable us to provide voting rights to holders of Exchangeable Shares and, in the future, to holders of other exchangeable shares that may be issued by Baytex or our other subsidiaries in connection with other exchangeable share transactions. For a description of the Exchangeable Shares, see "*Baytex Share Capital – Exchangeable Shares*".

An unlimited number of Special Voting Units may be created and issued pursuant to the Trust Indenture. Holders of Special Voting Units are not entitled to any distributions of any nature whatsoever from us and are entitled to such number of votes at meetings of Unitholders as may be prescribed by the Board of Directors. Except for the right to vote at meetings of Unitholders, the Special Voting Units do not confer upon the holders thereof any other rights.

Distribution Reinvestment Plan

On October 18, 2004, we implemented our DRIP which provides eligible Unitholders the advantage of accumulating additional Trust Units by reinvesting their cash distributions paid by us. The cash distributions are reinvested at our discretion, either by acquiring Trust Units issued from treasury at 95 percent of the "Average Market Price" (which is defined in the DRIP as the average trading price of the Trust Units on the Toronto Stock Exchange for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days) or by acquiring Trust Units at prevailing market rates. No commissions, service charges or brokerage fees are payable by participants in connection with Trust Units acquired under the DRIP. The DRIP is presently available to Canadian Unitholders only. Residents of the United States may not participate in the DRIP at this time.

Convertible Debentures

On June 6, 2005, we issued $100 million principal amount of Convertible Debentures. The Convertible Debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid Trust Units at a conversion price of $14.75 per Trust Unit. The Convertible Debentures mature on December 31, 2010 at which time they are due and payable. The Convertible Debentures are unsecured and are subordinate to the Credit Facilities. The Convertible Debentures are redeemable after December 31, 2008 at our option at a price of $1,050 per Convertible Debenture after December 31, 2008 and on or before December 31, 2009 and at a price of $1,025 per Debenture after December 31, 2009 and before maturity, in each case, plus accrued and unpaid interest thereon, if any. For a complete description of the Convertible Debentures, reference should be made to the indenture creating the Convertible Debentures, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on June 9, 2005).

Series A Debentures

On August 26, 2009, we issued $150 million principal amount of 9.15% Series A senior unsecured debentures. The Debentures pay interest semi-annually and mature on August 26, 2016 at which time they are due and payable. The Debentures are unsecured and therefore, for all practical purposes, are subordinate to the Credit Facilities. After August 26 of each of the following years, the Debentures are redeemable at our option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the Debentures) plus accrued and unpaid interest thereon, if any: 2012 at 104.575%; 2013 at 103.050%; 2014 at 101.525%; and 2015 at 100%. For a complete description of the Debentures, reference should be made to the Indenture, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on September 3, 2009).

Trust Indenture

The Trust Indenture, among other things, provides for the calling of meetings of Unitholders, the conduct of business thereof, notice provisions, the appointment and removal of the Trustee and the form of Trust Unit certificates. The Trust Indenture may be amended from time to time. Substantive amendments to the Trust Indenture, including our termination and the sale or transfer of our property as an entirety or substantially as an entirety requires approval by special resolution of the Unitholders. Any approval or consent of Unitholders in relation to any matter required by any regulatory body will require a majority of, or such other level of approval of Unitholders as may be stipulated by such regulatory authority, including as to the exclusion of interested or other Unitholders in the calculation of such level of approval.

The following is a summary of certain provisions of the Trust Indenture. For a complete description of the Trust Indenture, reference should be made to the Trust Indenture, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on June 5, 2008).

Unitholder Limited Liability

The Trust Indenture provides that no Unitholder, in its capacity as such, will incur or be subject to any liability in contract or in tort in connection with us or our obligations or affairs and, in the event that a court determines Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, our assets. Pursuant to the Trust Indenture, we have agreed to indemnify and hold harmless each Unitholder from any costs, damages, liabilities, expenses, charges or losses suffered by a Unitholder from or arising as a result of such Unitholder not having such limited liability.

The Trust Indenture provides that all contracts signed by or on behalf of us must contain a provision to the effect that such obligation will not be binding upon Unitholders personally. Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from our liabilities to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against us (to the extent that claims are not satisfied by us) that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The possibility of any personal liability to Unitholders of this nature arising is considered unlikely in view of the fact that our primary activity is to hold securities, and the majority of our business operations are currently carried on by Baytex.

Our activities and those of Baytex are conducted in such a way and in such jurisdictions so as to avoid as much as possible any material risk of liability to Unitholders for claims against us. These activities include obtaining appropriate insurance, where available, for the operations of Baytex and having contracts signed by or on behalf of us that include a provision that such obligations are not binding upon Unitholders personally.

In addition, on July 1, 2004 the *Income Trusts Liability Act* (Alberta) came into force, creating a statutory limitation on the liability of unitholders of Alberta income trusts such as us. The legislation provides that a unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee that arises after July 1, 2004.

Issuance of Trust Units

The Trust Indenture provides that Trust Units, including rights, warrants and other securities to purchase, to convert into or to exchange into Trust Units, may be created, issued, sold and delivered on such terms and conditions and at such times as the Trustee, upon the recommendation of the Board of Directors may determine. The Trust Indenture also provides that Baytex may authorize the creation and issuance of debentures, notes and other evidences of indebtedness of the Trust which debentures, notes or other evidences of indebtedness may be created and issued from time to time on such terms and conditions to such persons and for such consideration as Baytex may determine.

Cash Distributions

We make cash distributions on or about the 15th day following the end of each calendar month to Unitholders of record on or about the last business day of each such calendar month.

The Board of Directors on our behalf reviews our distribution policy from time to time. The actual amount distributed is dependent on the commodity price environment and is at the discretion of the Board of Directors. Our current distribution practice targets the use of between 50 to 60 percent of our funds from operations for capital expenditures. Depending upon commodity prices, between 50 to 60 percent of our funds from operations could fund up to all of our capital expenditures, including both exploration and development expenditures and minor property acquisitions, but excluding major acquisitions.

Pursuant to various agreements with Baytex's lenders, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on us or on our or our subsidiaries' ability to fulfill their obligations under the Credit Facilities or upon a material borrowing base shortfall or default.

Our Debentures also contain certain limitations on maximum cumulative distributions. Restricted payments include the declaration or payment of any dividend or distribution by us and the payment of interest or principal on subordinated debt owed by us. We and certain of our subsidiaries are restricted from making any restricted payments unless at the time of, and immediately after giving effect to, the proposed restricted payment, no default or event of default under the Indenture has occurred and is continuing, and either: (i) (a) we could incur at least $1.00 of additional indebtedness (other than certain permitted debt) in accordance with the "Limitation on Incurrence of Indebtedness and Issuance of Disqualified Stock" covenant in the Indenture; (b) the ratio of consolidated debt to consolidated cash flow from operations does not exceed 3.0 to 1.0; and (c) the aggregate amount of all restricted payments declared or made after August 26, 2009 (other than certain permitted restricted payments) does not exceed the sum of: (A) 80% of consolidated cash flow from operations accrued on a cumulative basis since August 26, 2009, plus (B) 100% of the aggregate net cash proceeds received by us after August 26, 2009 from (x) the issuance by us of convertible debentures, or (y) capital contributions in respect of certain permitted equity that we receive from any person; plus (C) the aggregate net proceeds, including the fair market value of property received after August 26, 2009 other than cash (as determined by the Board of Directors), received by us from any person, other than a subsidiary, from the issuance or sale of debt securities (including convertible debentures) or disqualified stock that have been converted into or exchanged for certain permitted equity of us, plus the aggregate net cash proceeds received by us at the time of such conversion or exchange; or (ii) the aggregate amount of all restricted payments declared or made pursuant to paragraph (i) does not exceed the sum of certain unpaid funds from restricted payments not previously expended under paragraph (i), plus $50,000,000.

Cash distributions on the Trust Units are paid at the discretion of the Board of Directors and can fluctuate depending on the level of funds from operations. The following table summarizes the cash distributions per Trust Unit paid by us since September, 2003. Our historical cash distributions may not be reflective of future cash distributions, which will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time. See "*Risk Factors*".

Month [(1)]	2010	2009	2008	2007	2006	2005	2004	2003
January	$0.18	$0.18	$0.18	$0.18	$0.18	$0.15	$0.15	-
February	0.18	0.12	0.18	0.18	0.18	0.15	0.15	-
March		0.12	0.20	0.18	0.18	0.15	0.15	-
April		0.12	0.20	0.18	0.18	0.15	0.15	-
May		0.12	0.20	0.18	0.18	0.15	0.15	-
June		0.12	0.25	0.18	0.18	0.15	0.15	-
July		0.12	0.25	0.18	0.18	0.15	0.15	-
August		0.12	0.25	0.18	0.18	0.15	0.15	-
September		0.12	0.25	0.18	0.18	0.15	0.15	$0.15
October		0.12	0.25	0.18	0.18	0.15	0.15	0.15
November		0.12	0.25	0.18	0.18	0.15	0.15	0.15
December		0.18	0.18	0.18	0.18	0.15	0.15	0.15
Total		$1.56	$2.64	$2.16	$2.16	$1.80	$1.80	$0.60

Note:

(1) Cash distributions are made on or about the 15th day following the end of each calendar month to Unitholders of record on or about the last business day of each such calendar month.

Distributions and Allocations of Trust Income

The Trust Indenture provides that distributable cash of the Trust shall be calculated for each period between distribution record dates, which are currently calendar months, provided that December 31 shall always be a distribution record date. The Trustee may, upon the recommendation of Baytex, declare payable and distribute all or part of the distributable cash to the Unitholders of record on the last day of each such calendar month. The Trust Indenture further provides that all net income, net realizable taxable gains and other income shall be distributed such that the Trust has no tax liability in any year. This income is allocated to Unitholders for tax purposes. In addition, the Trust Indenture provides that such income may be paid in whole or in part by cash or in Trust Units. The Trust Indenture also provides for the consolidation of the Trust Units at the discretion of the Board of Directors to the pre-distribution number of Trust Units after any pro-rata distribution of additional Trust Units to all unitholders.

The distribution by the Trust of such income is enforceable by Unitholders on the payment date determined by the Trustee.

For more information, see "*Risk Factors – Risks Associated with our Structure as a Trust – We allocate all of our income*".

Redemption Right

Trust Units are redeemable at any time on demand by the holders thereof upon delivery to us of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requiring redemption. Upon receipt of the notice to redeem Trust Units by us, the holder thereof will only be entitled to receive a price per Trust Unit equal to the lesser of: (i) 90 percent of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units are tendered to us for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the date that the Trust Units are so tendered for redemption.

For the purposes of this calculation, "market price" is an amount equal to the simple average of the closing price of the Trust Units for each of the trading days on which there was a closing price; provided that, if the applicable exchange or market does not provide a closing price but only provides the highest and lowest prices of the Trust Units traded on a particular day, the market price will be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the applicable exchange or market for fewer than five of the 10 trading days, the market price will be the simple average of the following prices established for each of the 10 trading days: the average of the last bid and last ask prices for each day on which there was no trading; the closing price of the Trust Units for each day that there was trading if the exchange or market provides a closing price; and the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The closing market price will be: an amount equal to the closing price of the Trust Units if there was a trade on the date; an amount equal to the average of the highest and lowest prices of the Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; and the average of the last bid and last ask prices if there was no trading on the date.

The aggregate amount payable by us in respect of any Trust Units surrendered for redemption during any calendar month will be satisfied by way of a cash payment on the last day of the following month. The entitlement of Unitholders to receive cash upon the redemption of their Trust Units is subject to the limitation that the total amount payable by us in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month and in any preceding calendar month during the same year will not exceed $100,000; provided that we may, in our sole discretion, waive such limitation in respect of any calendar month. If this limitation is not so waived, the price payable by us in respect of Trust Units tendered for redemption in such calendar month will be paid on the last day of the following month as follows: (i) firstly, by distributing Notes having an aggregate principal amount equal to the aggregate price of the Trust Units tendered for redemption; and (ii) secondly, to the extent that we do not hold Notes having a sufficient principal amount outstanding to effect such payment, by us issuing promissory notes to Unitholders who exercised the right of redemption having an aggregate principal amount equal to any such shortfall, which promissory notes ("**Redemption Notes**") will have terms and conditions substantially identical to those of the Notes.

If at the time Trust Units are tendered for redemption by a Unitholder, the outstanding Trust Units are not listed for trading on the Toronto Stock Exchange and are not traded or quoted on any other stock exchange or market which provides, in the sole discretion of Baytex, representative fair market value price for the Trust Units or trading of the outstanding Trust Units is suspended or halted on any stock exchange on which the Trust Units are listed for trading or, if not so listed, on any market on which the Trust Units are quoted for trading, on the date such Trust Units are tendered for redemption or for more than five trading days during the 10 trading day period, commencing immediately after the date such Trust Units were tendered for redemption, then such Unitholder will be entitled to receive a price per Trust Unit equal to 90 percent of the fair market value thereof as determined by Baytex as at the date on which such Trust Units were tendered for redemption. The aggregate price payable by us in such circumstances in respect of Trust Units tendered for redemption in any calendar month will be paid on the last day of the third following month by, at the option of the Trust: (i) a cash payment; or (ii) a distribution of Notes and/or Redemption Notes as described above.

It is anticipated that this redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. Notes or Redemption Notes which may be distributed *in specie* to Unitholders in connection with redemption will not be listed on any stock exchange and no market is expected to develop in such Notes or Redemption Notes. Notes or Redemption Notes may not be qualified investments for trusts governed by RRSPs, RESPs, DPSPs, RDSPs, TFSAs and RRIFs.

Non-resident Unitholders

It is intended that we comply with the requirements under the Tax Act for mutual fund trusts at all relevant times such that we maintain our status as a mutual fund trust for purposes of the Tax Act. If at any time we, or Baytex, become aware that our ability to continue to qualify as a mutual fund trust is in jeopardy, Baytex on our behalf, shall monitor the holdings of Trust Units by "non-residents" of Canada (within the meaning of the Tax Act) and shall take such steps as are necessary or desirable to ensure that we are not maintained primarily for the benefit of non-residents or that we are otherwise able to continue to qualify as a mutual fund trust for purposes of the Tax Act, including the imposition of restrictions on the issuance or transfer of Trust Units to such non-residents, the sale of Trust Units held by such non-residents and de-listing the Trust Units from any non-Canadian stock exchange. The Trust Indenture also provides that none of us, the Trustee, or Baytex shall have any liability to non-residents as a result of the sale of their Trust Units in order for us to maintain compliance with the requirements under the Tax Act for mutual fund trusts. As at December 31, 2009, approximately 36 percent of our Trust Units were held by non-residents.

Meetings of Unitholders

The Trust Indenture provides that meetings of Unitholders must be called and held for, among other matters, the election or removal of the Trustee, the appointment or removal of our auditors, the approval of amendments to the Trust Indenture (except as described under the subheading "*Amendments to the Trust Indenture*" below), the sale of our property as an entirety or substantially as an entirety, and the commencement of winding-up our affairs. Meetings of Unitholders will be called and held annually for, among other things, the election of the directors of Baytex and the appointment of our auditors. In certain circumstances, such as the election of directors of Baytex, the Trustee is required to seek direction from the Unitholders as to the manner in which it is to vote the shares of Baytex held by us. See " – *Exercise of Voting Rights Attached to Shares of Baytex*".

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened, except in certain circumstances, if requisitioned by the holders of not less than 20 percent of the Trust Units then outstanding by a written requisition. A requisition must, among other things, state in reasonable detail the business purpose for which the meeting is to be called.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate at least five percent of the votes attaching to all outstanding Trust Units will constitute a quorum for the transaction of business at all such meetings. For the purposes of determining such quorum, the holders of any issued Special Voting Units who are present at the meeting will be regarded as representing outstanding Trust Units equivalent in number to the votes attaching to such Special Voting Units.

The Trust Indenture contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders in accordance with the requirements of applicable laws.

Reporting to Unitholders

Our financial statements are audited annually by an independent recognized firm of chartered accountants. Our audited financial statements, together with the report of such chartered accountants, are mailed or otherwise delivered to Unitholders in accordance with applicable securities legislation and our unaudited interim financial statements are mailed or otherwise delivered to Unitholders in accordance with applicable securities legislation within the periods prescribed by such legislation. Our year end is December 31.

We are subject to the continuous disclosure obligations under all applicable securities legislation.

Take-over Bids

The Trust Indenture contains provisions to the effect that if a take-over bid is made for the Trust Units and not less than 90 percent of the Trust Units (other than Trust Units held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the take-over bid on the terms offered by the offeror.

The Trustee

Valiant Trust Company has been our trustee since our inception in 2003. The Trustee is responsible for, among other things, accepting subscriptions for Trust Units and issuing Trust Units pursuant thereto and providing timely reports to holders of Trust Units. The Trust Indenture provides that the Trustee will exercise its powers and carry out its functions thereunder as trustee honestly, in good faith and in our best interests and the interests of Unitholders and, in connection therewith, will exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Trustee is generally appointed for a three-year term by the Unitholders. At the end of such term, the Unitholders will either re-appoint the Trustee or appoint a successor trustee for an additional three-year term. The Trustee may be removed by a special resolution of Unitholders. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee.

Delegation of Authority, Administration and Trust Governance

The Board of Directors has generally been delegated by the Trustee the significant management decisions relating to us. In particular, the Trustee has delegated to Baytex responsibility for any and all matters relating to the following: (i) an offering; (ii) ensuring compliance with all applicable laws, including in relation to an offering; (iii) all matters relating to the content of any offering documents, the accuracy of the disclosure contained therein, and the certification thereof; (iv) all matters concerning the terms of, and amendment from time to time of, our material contracts; (v) all matters concerning any underwriting or agency agreement providing for the sale of Trust Units or rights to Trust Units; (vi) all matters relating to the maximization of Unitholder value in the context of a response to an offer for Trust Units or for all or substantially all of the property and assets of us or Baytex; (vii) all matters relating to the redemption of Trust Units; (viii) all matters relating to the voting rights on any investments in our assets or any subsequent investments; (ix) all matters relating to the specific powers and authorities as set forth in the Trust Indenture.

Liability of the Trustee

The Trustee, its directors, officers, employees, shareholders and agents are not liable to any Unitholder or any other person, in tort, contract or otherwise, in connection with any matter pertaining to us or our property, arising from the exercise by the Trustee of any powers, authorities or discretion conferred under the Trust Indenture, including, without limitation, an administration agreement in place between us and Baytex, and relying on Baytex thereunder, any action taken or not taken in good faith in reliance on any documents that are, *prima facie*, properly executed, any depreciation of, or loss to, our property incurred by reason of the sale of any asset, any inaccuracy in any evaluation provided by any appropriately qualified person, any reliance on any such evaluation, any action or failure to act of Baytex, or any other person to whom the Trustee has, with the consent of Baytex, delegated any of its duties thereunder, or any other action or failure to act (including failure to compel in any way any former trustee to redress any breach of trust or any failure by Baytex to perform its duties under or delegated to it under the Trust Indenture or any other contract), including anything done or permitted to be done pursuant to, or any error or omission relating to, the rights, powers, responsibilities and duties conferred upon, granted, allocated and delegated to Baytex thereunder or under the administration agreement, or the act of agreeing to the conferring upon, granting, allocating and delegating any such rights, powers, responsibilities and duties to Baytex in accordance with the terms of the Trust Indenture or under the administration agreement, unless and to the extent such liabilities arise out of the gross negligence, wilful default or fraud of the Trustee or any of its directors, officers, employees, shareholders, or agents.

If the Trustee has retained an appropriate expert or advisor or legal counsel with respect to any matter connected with its duties under the Trust Indenture or any other contract, the Trustee may act or refuse to act based on the advice of such expert, advisor or legal counsel, and notwithstanding any other provision of the Trust Indenture, the Trustee will not be liable for and will be fully protected from any loss or liability occasioned by any action or refusal to act based on the advice of any such expert, advisor or legal counsel. In the exercise of the powers, authorities or discretion conferred upon the Trustee under the Trust Indenture, the Trustee is and will be conclusively deemed to be acting as Trustee of our assets and will not be subject to any personal liability for any debts, liabilities, obligations, claims, demands, judgments, costs, charges or expenses against or with respect to us or our property. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Amendments to the Trust Indenture

The Trust Indenture may be amended or altered from time to time by a special resolution of Unitholders.

The Trustee may, without the approval of any of Unitholders, amend the Trust Indenture for the purpose of:

(a) ensuring our continuing compliance with applicable laws or requirements of any governmental agency or authority of Canada or of any province;

(b) ensuring that we will satisfy the provisions of each of subsections 108(2) and 132(6) of the Tax Act, as amended or replaced from time to time;

(c) ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;

(d) removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or any supplemental indenture and any other agreement of us or any offering document pursuant to which our securities are issued with respect us, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee and of Unitholders are not prejudiced thereby; and

(e) curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee the rights of the Trustee and of Unitholders are not prejudiced thereby.

Termination of the Trust

The Unitholders may vote to terminate the Trust at any meeting of Unitholders duly called for that purpose, subject to the following: (a) a vote may only be held if requested in writing by the holders of not less than 20 percent of the outstanding Trust Units; (b) a quorum of 50 percent of the issued and outstanding Trust Units is present in person or by proxy; and (c) the termination must be approved by special resolution of Unitholders.

Unless the Trust is earlier terminated or extended by vote of Unitholders, the Trustee will commence to wind-up our affairs on December 31, 2099. In the event that we are wound-up, the Trustee will sell and convert into money our property in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate our property, and will in all respects act in accordance with the directions, if any, of Unitholders in respect of termination authorized pursuant to the special resolution authorizing our termination. After paying, retiring or discharging or making provision for the payment, retirement or discharge of all our known liabilities and obligations and providing for indemnity against any other outstanding liabilities and obligations, the Trustee will distribute the remaining part of the proceeds of the sale of the assets together with any cash forming part of our property among Unitholders in accordance with their pro rata holdings.

Exercise of Voting Rights Attached to Shares of Baytex

The Trust Indenture prohibits the Trustee from voting the shares of Baytex with respect to: (i) the election of directors of Baytex; (ii) the appointment of auditors of Baytex; or (iii) the approval of Baytex's financial statements, except in accordance with an ordinary resolution adopted at an annual meeting of Unitholders. The Trustee is also prohibited from voting the shares to authorize:

(a) any sale, lease or other disposition of, or any interest in, all or substantially all of the assets of Baytex, except in conjunction with an internal reorganization of the direct or indirect assets of Baytex as a result of which either Baytex or the Trust has the same interest, whether direct or indirect, in the assets as the interest, whether direct or indirect, that it had prior to the reorganization;

(b) any statutory amalgamation of Baytex with any other corporation, except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(c) any statutory arrangement involving Baytex except in conjunction with an internal reorganization as referred to in paragraph (a) above;

(d) any amendment to the articles of Baytex to increase or decrease the minimum or maximum number of directors; or

(e) any material amendment to the articles of Baytex to change the authorized share capital other than the creation of additional classes of Exchangeable Shares or to amend the rights, privileges, restrictions and conditions attaching to any class of Baytex's shares in a manner which may be prejudicial to us, without the approval of Unitholders by special resolution at a meeting of Unitholders called for that purpose.

ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY LTD.

Management of the Trust

The following table sets forth the name, municipality of residence, age as at December 31, 2009, position held with Baytex and principal occupation of each of the directors and officers of Baytex.

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
John A. Brussa (2) (3) (4) (6) Calgary, Alberta	52	Director	Partner with Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	54	Director and Executive Chairman	Executive Chairman of Baytex
Edward Chwyl (2) (3) (4) Victoria, B.C.	66	Director	Independent Businessman
Naveen Dargan (1) (2) (4) Calgary, Alberta	52	Director	Independent Businessman
R.E.T. (Rusty) Goepel (1) Vancouver, B.C.	67	Director	Senior Vice President of Raymond James Ltd.
Anthony W. Marino Calgary, Alberta	49	Director, President and Chief Executive Officer	President and Chief Executive Officer of Baytex
Gregory K. Melchin (1) Calgary, Alberta	56	Director	Independent Businessman
Dale O. Shwed (3) Calgary, Alberta	51	Director	President and Chief Executive Officer of Crew Energy Inc.

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
W. Derek Aylesworth Calgary, Alberta	47	Chief Financial Officer	Chief Financial Officer of Baytex
Randal J. Best Calgary, Alberta	53	Senior Vice President, Corporate Development	Senior Vice President, Corporate Development of Baytex
Stephen Brownridge Calgary, Alberta	50	Vice President, Exploration	Vice President, Exploration of Baytex
Murray J. Desrosiers Calgary, Alberta	40	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary of Baytex
Brett J. McDonald Calgary, Alberta	47	Vice President, Land	Vice President, Land of Baytex
Timothy R. Morris Denver, Colorado	53	Vice President, US Business Development	Vice President of Baytex USA
R. Shaun Paterson Calgary, Alberta	56	Vice President, Marketing	Vice President, Marketing of Baytex
Marty L. Proctor Calgary, Alberta	49	Chief Operating Officer	Chief Operating Officer of Baytex
Richard P. Ramsay Calgary, Alberta	46	Vice President, Heavy Oil	Vice President, Heavy Oil of Baytex
Mark F. Smith Calgary, Alberta	52	Vice President, Conventional Oil & Gas	Vice President, Conventional Oil & Gas of Baytex

Notes:

(1) Member of our Audit Committee.

(2) Member of our Compensation Committee.

(3) Member of our Reserves Committee.

(4) Member of our Nominating and Governance Committee.

(5) Baytex's directors hold office until the next annual general meeting of Unitholders or until each director's successor is appointed or elected pursuant to the *Business Corporations Act* (Alberta).

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

Listed below is a biographical description for each of our directors and officers, including their principal occupations during the five preceding years.

John A. Brussa became a Director of Baytex on October 8, 1997. He is a partner at Burnet, Duckworth & Palmer LLP and focuses on tax law. He was admitted to the Alberta bar in 1982. Mr. Brussa is a director of several public companies including Crew Energy Inc., Just Energy Income Fund, Progress Energy Resources Corp., Penn West Energy Trust and Storm Exploration Inc. He holds a Bachelor of Laws degree from the University of Windsor where he was a gold medalist and a Bachelor of Arts, History and Economics degree also from the University of Windsor.

Raymond T. Chan was appointed Executive Chairman of Baytex on January 1, 2009. He originally joined Baytex in October 1998 and has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to August 2003); President and Chief Executive Officer (September 2003 to November 2007); and Chief Executive Officer (November 2007 to December 2008). Mr. Chan has been a director of Baytex since October 1998. Mr. Chan has held senior executive positions in the Canadian oil and gas industry since 1982, including chief financial officer titles at Tarragon Oil and Gas Limited, American Eagle Petroleums Ltd. and Gane Energy Corporation. Mr. Chan holds a Bachelor of Commerce degree and is a chartered accountant.

Edward Chwyl became a Director of Baytex on May 27, 2003 and was Chairman of the Board of Directors from September 2003 to December 2008. He was appointed Lead Independent Director of Baytex on February 17, 2009. He holds a Bachelor of Science degree in Chemical Engineering and a Master of Science degree in Petroleum Engineering. He is a retired businessman with over 35 years experience in the oil and gas industry in North America, most notably as President and Chief Executive Officer of Tarragon Oil and Gas Limited from 1989 to 1998. Prior thereto, he held various technical and executive positions within the oil and gas industry in Canada and the United States.

Naveen Dargan became a Director of Baytex on September 1, 2003. He has been an independent businessman since June 2003. Prior to this, he held the position of Senior Managing Director and Head of Energy Investment Banking at Raymond James Ltd., an investment banking firm and its predecessor companies. Mr Dargan is a director of Trinidad Drilling Ltd. and CCS Corporation. He holds a Bachelor of Arts (Honours) degree in Mathematics and Economics, a Master of Business Administration degree and a Chartered Business Valuator designation.

R.E.T. (Rusty) Goepel became a Director of Baytex on May 11, 2005. He is currently Senior Vice President for Raymond James Ltd. He commenced his career in investment banking in 1968 and was President and co-founder of Goepel Shields & Partners, which later became Goepel McDermid Ltd. and was acquired by Raymond James Ltd. in 2001. Mr. Goepel holds a Bachelor of Commerce (Honours) degree.

Anthony W. Marino was appointed President, Chief Executive Officer and director of Baytex on January 1, 2009. Mr. Marino joined Baytex in November 2004 as Chief Operating Officer and was promoted to President and Chief Operating Officer in November 2007. Prior to joining Baytex, Mr. Marino was President and Chief Executive Officer of Dominion Exploration Canada Ltd. (a subsidiary of Dominion Resources Inc.). Mr. Marino’s earlier experience includes managing the Jonah/Pinedale asset area for AEC Oil and Gas (USA) Inc., operations and business development management for Santa Fe Snyder Corp. and several technical and management positions with Atlantic Richfield Company. He is a registered professional engineer and a Chartered Financial Analyst, and has over 25 years of experience in the North American oil and gas industry. Mr. Marino has a Bachelor of Science degree with Highest Distinction in Petroleum Engineering from the University of Kansas and a Masters of Business Administration degree from California State University at Bakersfield. He is currently a member of the Board of Governors for the Canadian Association of Petroleum Producers and was previously a member of the Board of Directors for the Independent Petroleum Association of Mountain States in the United States.

Gregory K. Melchin became a director of Baytex on May 20, 2008. Mr. Melchin was a member of the Legislative Assembly of Alberta from 1997 to March 2008. Among his various assignments with the Government of Alberta, he was Minister of Energy, Minister of Seniors and Community Supports and Minister of Revenue. Prior to being elected to the Legislative Assembly of Alberta, he served in various management positions for twenty years in the Calgary business community. Mr. Melchin holds a Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. He has also completed the Directors Education Program with the Institute of Corporate Directors.

Dale O. Shwed became a Director of Baytex on June 3, 1993. He has held the position of President and Chief Executive Officer of Crew Energy Inc., a public oil and gas company, since September 2003. Prior thereto, he was President and Chief Executive Officer of Baytex from 1993 to August 2003. Mr. Shwed holds a Bachelor of Science degree specializing in Geology.

W. Derek Aylesworth joined Baytex as Chief Financial Officer in November 2005, and is responsible for Baytex's capital markets, financial reporting and compliance, financial risk management, tax and treasury functions. Prior to joining Baytex, Mr. Aylesworth held the position of Commercial Manager of the Ecuador Region business unit at

EnCana Corporation. Prior thereto, he was the Division Vice President for the International New Ventures Exploration business unit of the same company. Mr. Aylesworth has over 20 years of experience in the Canadian oil and gas industry. Mr. Aylesworth holds a Bachelor of Commerce degree and is a chartered accountant with expertise in taxation and has experience as a tax advisor in both the oil and gas industry and public practice in Calgary.

Randal J. Best was appointed Senior Vice President, Corporate Development of Baytex in December 2006 and is responsible for asset and corporate acquisitions and divestitures, corporate planning and reserves. Prior thereto, he was Vice President, Corporate Development of Baytex since September 2003. From 2000 to 2003 he was Managing Director of Waterous Securities, a private oil & gas investment bank specializing in mergers and acquisitions, and previous to that he was President and Chief Executive Officer of Enercap Corporation, a private investment company. Mr. Best has over 25 years of experience in the Canadian oil and gas industry and is a professional engineer. He holds a Bachelor of Applied Science degree in Chemical Engineering from the University of Waterloo and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Stephen Brownridge was appointed Vice President, Exploration on January 5, 2010. Mr. Brownridge has over 20 years experience in the Canadian oil and gas industry. He joined Baytex in 1997 and held the position of Manager of the Heavy Oil Business Unit from September 2003 to December 2006 and Vice President, Heavy Oil from December 2006 to January 2010. Prior to joining Baytex, Mr. Brownridge held technical positions with Koch Exploration Canada Corporation and Rigel Oil and Gas Ltd. Mr. Brownridge holds a Bachelor of Science degree with Honours in Geology from the University of Manitoba, and a Master of Science Degree in Geology obtained jointly from the University of Alberta and Louisiana State University.

Murray J. Desrosiers was appointed Vice President, General Counsel and Corporate Secretary on May 20, 2009. Mr. Desrosiers is a corporate lawyer with over 14 years of experience advising energy companies in the areas of corporate finance, mergers and acquisitions, corporate governance and securities compliance matters. He joined Baytex in July 2008 and held the position of General Counsel from August 2008 to May 2009. Prior to joining Baytex, he held senior legal positions with PrimeWest Energy Inc. (the operating company of PrimeWest Energy Trust), Shiningbank Energy Ltd. (the operating company of Shiningbank Energy Income Fund), Enbridge Inc. and Enbridge Management Services Inc. (the manager of Enbridge Income Fund). Mr. Desrosiers holds a Bachelor of Laws from the University of Alberta and a Bachelor of Commerce (Finance) from the University of Calgary and is a member of the Law Society of Alberta.

Brett J. McDonald was appointed Vice President, Land on December 1, 2006. Mr. McDonald has over 25 years of experience in the Canadian oil and gas industry. He joined Baytex in 2000 and held the position of General Manager of Land from September 2003 to December 2006. Prior to joining Baytex, Mr. McDonald held senior land negotiating positions with Newport Petroleum Corporation, Stampeder Exploration Ltd. and Murphy Oil Company Ltd. Mr. McDonald is a member of the Canadian Association of Petroleum Landmen.

Timothy R. Morris joined Baytex as Managing Director, U.S. Business Development in April 2007 and was appointed Vice President, U.S. Business Development on November 12, 2007. Mr. Morris has over 31 years of experience in the United States oil and gas industry. Prior to joining Baytex, he held senior management positions with Berco Resources, LLC, Santa Fe Snyder Corporation, Snyder Oil Corporation, Petroleum, Inc. and Sohio Petroleum Corp. He received a Bachelor of Science degree with an area of emphasis in Minerals Land Management from the University of Colorado and is a Certified Professional Landman. He is an member of the Independent Petroleum Association of Mountain States, Denver Association of Petroleum Landmen and the American Association of Professional Landmen.

R. Shaun Paterson was appointed Vice President, Marketing on December 11, 2006, and is responsible for the transportation and marketing of Baytex's production and implementing its commodity price risk mitigation strategies. Mr. Paterson has over 29 years of experience in the Canadian oil and gas industry. Prior to joining Baytex, he worked for EnCana Corporation as Vice President of Domestic Crude Oil Marketing. Prior to this assignment, Mr. Paterson held senior marketing and business development positions with Dynegy and Chevron. Mr. Paterson holds a Bachelor of Science degree in Mechanical Engineering from the University of Alberta.

Marty L. Proctor joined Baytex as Chief Operating Officer on January 14, 2009. Mr. Proctor has over 25 years of experience in the Canadian and international oil and gas industries, with particular emphasis in heavy oil operations.

Prior to joining Baytex, he was Senior Vice President responsible for upstream operations for StatoilHydro Canada. Prior to that, Mr. Proctor was Senior Vice President of North American Oil Sands Corporation and Vice President of Murphy Oil Company. Earlier in his career, he held technical and management positions with Maxx Petroleum, Central Resources (USA), BP Resources Canada and Husky Oil. Mr. Proctor earned both Bachelor and Master of Science degrees in Petroleum Engineering from the University of Alberta, where his research focused on thermal oil recovery. Mr. Proctor is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and is a member of the Canadian Heavy Oil Association and the Society of Petroleum Engineers.

Richard P. Ramsay joined Baytex as Vice President, Heavy Oil on January 5, 2010. Mr. Ramsay has over 20 years of experience in the Canadian oil and gas industry and was formerly Chief Operating Officer of TAQA North Ltd. He previously held a variety of technical and management positions with Northrock Resources Ltd., Fletcher Challenge Energy Canada Inc., Amoco Canada Petroleum Ltd. and Dome Petroleum Ltd. Mr. Ramsay has a Bachelor of Science degree with Distinction in Mechanical Engineering from the University of Saskatchewan and is a practicing member of the Association of Professional Engineers, Geologists and Geophysists of Alberta.

Mark F. Smith joined Baytex as Vice President, Conventional Oil and Gas on November 20, 2006. Mr. Smith has over 25 years of industry experience primarily focused in the Western Canadian Sedimentary Basin. Prior to joining Baytex, Mr. Smith was Vice President, Development of the North Business Unit of Burlington Resources Canada/ConocoPhillips Canada. Prior to this assignment, Mr. Smith held a variety of management and operations positions with Burlington Resources Canada and Poco Petroleums Ltd. Mr. Smith holds a Bachelor of Chemical Engineering Science Degree from the University of Western Ontario and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

Ownership of Securities by Management

As at March 1, 2010, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,556,053 Trust Units, or approximately 1.4 percent of the issued and outstanding Trust Units. No Convertible Debentures or Debentures were owned by this same group.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

No director or executive officer of Baytex (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including Baytex), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer or was subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

Except as disclosed above under "*Additional Information Respecting Baytex Energy Ltd. – Management of the Trust*", no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities of to materially affect control of us, is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including Baytex) that, while that person was acting in that 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 or has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver-manager or trustee appointed to hold the assets of the director, executive officer or shareholder.

In addition, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities of to materially affect control of us, has been subject to 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 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.

Conflicts

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

Personnel

As at December 31, 2009, we had 144 employees in our Calgary head office, 11 employees in our Denver office and 45 employees in our field operations.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The text of the Audit Committees' Mandate and Terms of Reference is attached as Appendix C.

Composition of the Audit Committee

The members of our Audit Committee are Naveen Dargan, R.E.T. (Rusty) Goepel and Gregory K. Melchin, each of whom is "independent" and "financially literate", with the meaning of National Instrument 52-110 "Audit Committees". The relevant education and experience of each Audit Committee member is outlined below:

Name	Independent	Financially Literate	Relevant Education and Experience
Naveen Dargan	Yes	Yes	Bachelor of Arts (Honours) degree in Mathematics and Economics, Master of Business Administration degree and Chartered Business Valuator designation. Independent businessman since June 2003; prior thereto Senior Managing Director and Head of Energy Investment Banking of Raymond James Ltd.
R.E.T. (Rusty) Goepel	Yes	Yes	Bachelor of Commerce (Honours) degree. Has over 40 years experience in the investment industry. Currently a Senior Vice President with Raymond James Ltd. (investment dealer). From 2004 to 2009, he was a member of the Audit Committee of TELUS Corporation, a telecommunications company that is listed on the TSX and the NYSE.

Name	Independent	Financially Literate	Relevant Education and Experience
Gregory K. Melchin	Yes	Yes	Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. Also completed the Directors Education Program with the Institute of Corporate Directors. Member of the Legislative Assembly of Alberta from 1997 to March 2008. Prior to being elected to the Legislative Assembly of Alberta, served in various management positions for 20 years in the Calgary business community.

Pre-Approval of Policies and Procedures

Although the Audit Committee has not adopted specific policies and procedures for the engagement of non-audit services by our auditors, it does pre-approve all non-audit services to be provided to us and our subsidiaries by the external auditors. The pre-approval for recurring services such as preliminary work on the integrated audit, securities filings, planning for conversion to International Financial Reporting Standards, translation of the Trust's financial statements and related management's discussion and analysis into the French language and tax and tax-related services is provided on an annual basis and other services are subject to pre-approval as required.

External Auditor Service Fees

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by Deloitte & Touche LLP, our external auditors, during fiscal 2009 and 2008:

	Aggregate fees billed ($000s)	
	2009	**2008**
Audit Fees	$1,253	$1,124
Audit-Related Fees	-	-
Tax Fees	193	56
All Other Fees	-	84
	$1,446	$1,264

Audit Fees: Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. In addition to the fees for annual audits of financial statements and review of quarterly results, services in this category for fiscal 2009 and 2008 also include the reviews of comment letters from Canadian and U.S. regulatory agencies, amounts for audit work performed in relation to the requirements of Section 404 of the *Sarbanes-Oxley Act of 2002* relating to internal control over financial reporting and review of prospectuses related to equity and debt issuances.

Audit-Related Fees: Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit or review of our financial statements and are not reported as Audit Fees.

Tax Fees: Tax fees included tax planning and various taxation matters.

All Other Fees: During 2008, the services provided in this category consisted only of advisory services associated with property taxes.

BAYTEX SHARE CAPITAL

Baytex is authorized to issue an unlimited number of common shares and an unlimited number of Exchangeable Shares. As of the date hereof, we were the sole holder of the issued and outstanding common shares of Baytex and there were no Exchangeable Shares outstanding.

The following is a summary of certain provisions of the share capital of Baytex. For a complete description of the share provisions, reference should be made to the Articles of Baytex, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on June 5, 2008).

Common Shares

Each Baytex common share entitles its holders to receive notice of and to attend all meetings of the shareholders of Baytex and to one vote at such meetings. The holders of common shares will be, at the discretion of the Board of Directors and subject to applicable legal restrictions, and subject to certain preferences of holders of Exchangeable Shares, entitled to receive any dividends declared by the Board of Directors on the common shares to the exclusion of the holders of Exchangeable Shares, subject to the proviso that no dividends will be paid on the common shares unless all declared dividends on the outstanding Exchangeable Shares have been paid in full. The holders of common shares are entitled to share equally in any distribution of the assets of Baytex upon the liquidation, dissolution, bankruptcy or winding-up of Baytex or other distribution of its assets among its shareholders for the purpose of winding-up its affairs. Such participation is subject to the rights, privileges, restrictions and conditions attaching to the Exchangeable Shares and any other shares having priority over the common shares. As at December 31, 2009, all of the common shares of Baytex are owned by us.

Exchangeable Shares

Each Exchangeable Share has economic rights (including the right to have the Exchange Ratio adjusted to account for distributions paid to Unitholders) and voting attributes (through the benefit of the Special Voting Units) equivalent to those of the Trust Units into which they are exchangeable from time to time. In addition, holders of Exchangeable Shares have the right to receive Trust Units at any time in exchange for their Exchangeable Shares, on the basis of the Exchange Ratio in effect at the time of the exchange. Holders of Exchangeable Shares do not receive cash distributions.

On May 30, 2008, the Trust announced that Baytex had elected to redeem all of its Exchangeable Shares outstanding on August 29, 2008 for Trust Units based on the Exchange Ratio in effect on August 28, 2008. In connection with this redemption, Baytex ExchangeCo Ltd. exercised its overriding "redemption call right" to purchase such Exchangeable Shares.

MARKET FOR SECURITIES

The Trust Units are listed and posted for trading on the Toronto Stock Exchange and the New York Stock Exchange under the trading symbols BTE.UN and BTE, respectively. The Convertible Debentures are listed and posted for trading on the Toronto Stock Exchange under the trading symbol BTE.DB.

The following table sets forth the high and low trading prices and the aggregate volume of trading of the Trust Units, as reported by the Toronto Stock Exchange and the New York Stock Exchange for the periods indicated. The Trust Units commenced trading on the Toronto Stock Exchange on September 8, 2003 and on the New York Stock Exchange on March 27, 2006.

	Toronto Stock Exchange			New York Stock Exchange		
	Price Range			Price Range		
	High ($)	**Low ($)**	**Volume Traded**	**High ($US)**	**Low ($US)**	**Volume Traded**
2003	10.89	9.19	40,973,662	-	-	-
2004	14.00	9.78	93,252,808	-	-	-
2005	18.78	12.42	87,481,272	-	-	-
2006	28.66	16.81	102,652,240	25.87	16.63	21,496,200
2007	22.92	16.68	86,185,013	21.74	15.51	18,062,500
2008	35.37	12.81	123,417,418	35.20	10.16	34,513,640
2009						
January	17.49	14.20	10,049,252	14.85	11.55	3,687,803
February	14.46	9.77	13,997,248	11.95	7.84	4,270,423
March	16.27	10.65	14,942,679	13.15	8.27	4,586,295
April	17.41	14.89	8,103,085	14.50	11.76	3,474,830
May	19.59	16.56	8,028,364	17.93	13.93	3,013,074
June	20.18	17.05	9,321,111	18.42	14.77	2,937,685
July	22.59	17.80	8,927,516	20.89	15.20	2,386,699
August	24.99	21.62	8,130,776	23.12	20.19	1,933,678
September	25.35	22.37	7,826,271	23.69	20.47	1,457,974
October	28.12	21.57	10,129,575	26.75	19.83	2,431,241
November	28.35	25.65	6,312,770	26.83	23.76	1,699,099
December	30.50	27.03	6,377,808	29.32	25.55	1,362,113
2010						
January	32.02	29.64	6,047,742	31.07	28.49	1,204,090
February	33.74	29.50	5,564,579	32.19	27.56	1,524,980

The following table sets forth the high and low trading prices and the aggregate volume of trading of the Convertible Debentures as reported by the Toronto Stock Exchange for the periods indicated. The Convertible Debentures commenced trading on the Toronto Stock Exchange on June 6, 2005.

	Price Range		
	High ($)	**Low ($)**	**Volume Traded**
2005	127.00	99.50	76,697.5
2006	190.88	114.83	55,069.8
2007	150.00	115.00	2,874.5
2008	235.24	94.60	5,343.0
2009			
January	104.32	100.00	12.0
February	100.00	93.03	155.0
March	107.77	101.77	46.0
April	114.51	105.96	156.0
May	126.16	118.51	68.0
June	131.21	120.48	75.0
July	150.00	128.69	553.0
August	166.00	148.00	267.0
September	169.00	153.71	149.0
October	188.00	157.50	617.0
November	188.00	177.50	280.0
December	200.00	186.85	213.0
2010			
January	215.00	193.54	341.2
February	225.00	207.70	231.3

RATINGS

On November 26, 2009, Dominion Bond Rating Service Limited ("**DBRS**") confirmed our stability rating of STA-5 (low). The stability rating is based on a rating scale developed by DBRS that provides an indication of both the stability and sustainability of an income fund's distributions per unit. Stability rating categories range from STA-1 to STA-7, with STA-1 being the highest and STA-7 being the lowest possible rating. DBRS further separates the ratings into high, middle and low to indicate relative standing within a rating category. Ratings take into consideration the seven main factors of: (1) operating and industry characteristics; (2) asset quality; (3) financial flexibility; (4) diversification; (5) size and market position; (6) sponsorship/governance; and (7) growth. In addition, consideration is given to specific structural or contractual elements that may eliminate or mitigate risks or other potentially negative factors. Income funds rated at STA-5 have weak distributions per unit stability and sustainability. These funds are subject to many of the same cyclical, seasonal, and economic factors as in the STA-4 rating category, but the lack of diversification is generally more pronounced, and will tend to be below average in several areas considered when determining a stability rating.

Baytex has been assigned a corporate family credit rating of B1 and our Debentures have been assigned a credit rating of B3, each with a stable outlook by Moody's Investor Service Inc. ("**Moody's**"). Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, securities rated "B" are considered speculative and are subject to high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from AA through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category.

Baytex has been assigned a corporate credit rating of BB-/Positive and its our Debentures have been assigned a credit rating of B by Standard and Poor's Rating Services, a division of McGraw-Hill Companies (Canada) Corporation ("**S&P**"). S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. According to the S&P rating system, debt rated "BB" is considered less vulnerable to non-payment than other speculative issues, however it faces ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inability to meet its financial obligations. An obligation rated "B" is more vulnerable to non-payment than those rated BB, but the obligor currently has the capacity to meet its financial commitments on the obligation. Adverse business, financial, or economic conditions will likely impair the obligor's capacity or willingness to meet its financial commitment on the obligation. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

The stability rating accorded to us by DBRS and the credit ratings accorded to Baytex by Moody's and S&P are not recommendations to purchase, hold or sell any of our securities inasmuch as such ratings do not comment as to market price or suitability for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings that we or Baytex or any subsidiary of us or Baytex is or was a party to, or that any of our property is or was the subject of, during our most recently completed financial year, that were or are material to us or Baytex, and there are no such material legal proceedings that we are currently aware of that are contemplated.

There were no: (i) penalties or sanctions imposed against us or Baytex by a court relating to securities legislation or by a securities regulatory authority during our most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us or Baytex that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into with a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors and executive officers of Baytex, any holder of Trust Units who beneficially owns or controls or directs, directly of indirectly, more than 10 percent of the outstanding Trust Units, or any known associate or affiliate of such persons, in any transactions since our inception or since the beginning of our last completed financial year which has materially affected or is reasonably expected to materially affect us or Baytex.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Deloitte & Touche LLP, Chartered Accountants, Calgary, Alberta, is our auditor and is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Valiant Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar for the Trust Units and the Convertible Debentures.

INTERESTS OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by us during, or related to, our most recently completed financial year other than Sproule, our independent engineering evaluator. None of the designated professionals of Sproule have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared a report, valuation, statement or opinion prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of Baytex or of any associate or affiliate of Baytex, except for John Brussa, a director of Baytex, who is a partner at Burnet, Duckworth & Palmer LLP, a law firm that renders legal services to us.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by us within the most recently completed financial year, or before the most recently completed financial year but are still material and are still in effect, are the following:

(a) the Trust Indenture (filed on SEDAR on June 5, 2008);

(b) the NPI Agreement (filed on SEDAR on March 16, 2009);

(c) the indenture creating the Note and the promissory note evidencing the Notes issued there under (filed on SEDAR on March 21, 2005);

(d) the indenture creating the Convertible Debentures (filed on SEDAR on June 9, 2005);

(e) the indenture creating the Debentures (filed on SEDAR on September 3, 2010);

(f) our trust unit rights incentive plan (filed on SEDAR on November 26, 2009); and

(g) the credit agreement (and amendments thereto) in respect of our $515 million syndicated credit facility (filed on SEDAR on March 28, 2008, September 15, 2008, July 9, 2009, August 14, 2009 and October 5, 2009).

Copies of each of these contracts are accessible on the SEDAR website at *www.sedar.com*.

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB and the issuance of such a licence requires a public hearing and the approval of the Governor in Council.

Natural Gas

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

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

Pipeline Capacity

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

The North American Free Trade Agreement

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

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector by 2010 and prohibits discriminatory border restrictions and export taxes. NAFTA also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes, minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

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

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

Alberta

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

On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" ("**NRF**") containing the Government's proposals for Alberta's new royalty regime which were subsequently implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*. The NRF took effect on January 1, 2009. On March 11, 2010, the Government of Alberta announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the upstream oil and natural gas sectors; specifically, the maximum royalty rates for conventional oil and natural gas production will be decreased effective for the January 2011 production month and certain temporary incentive programs currently in place will be made permanent. Further details with respect to the changes to Alberta's royalty system are expected to be provided in the coming months.

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 range from 0-50%, an increase from the previous maximum rates of 30-35% depending on the vintage of the oil, and rate caps are set at $120 per barrel. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 40%.

Royalty rates for natural gas under the NRF are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Royalty rates for natural gas under the NRF range from 5-50%, an increase from the previous maximum rates of 5-35%, and rate caps are set at $17.75/GJ. Effective January 1, 2011, the maximum royalty payable under the NRF will be reduced to 36%.

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

In August 2006, the Government of Alberta introduced the Innovative Energy Technologies Program (the "**IETP**"), which has a stated objective of promoting producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP is backed by a $200 million funding commitment over a five-year period beginning April 1, 2005 and provides royalty adjustments to specific pilot and demonstration projects that utilize innovative technologies to increase recovery from existing reserves.

On April 10, 2008, the Government of Alberta introduced two new royalty programs to be implemented along with the NRF and intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre.

On November 19, 2008, in response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The 5-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well’s life when production rates are expected to be the highest. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the NRF. Pursuant to the changes made to Alberta's royalty structure announced on March 11, 2010, producers will only be able to elect to adopt the transitional royalty rates prior to January 1, 2011 and producers that have already elected to adopt the transitional royalty rates as of that date will be permitted to switch to Alberta's conventional royalty structure. On December 31, 2013, all producers operating under the transitional royalty rates will automatically become subject to Alberta's conventional royalty structure.

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

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, and make monthly royalty payments in respect of oil and natural gas produced. The amount payable as a royalty in respect of oil depends on the type and vintage of the oil, the quantity of oil produced in a month and the value of that oil. Generally, oil is classified as either light or heavy and the vintage of oil is based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). The royalty calculation takes into account the production of oil on a well-by-well basis, the specified royalty rate for a given vintage of oil, the average unit selling price of the oil and any applicable royalty exemptions. Royalty rates are reduced on low productivity wells, reflecting the higher unit costs of extraction, and are the lowest for third-tier oil, reflecting the higher unit costs of both exploration and extraction.

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas as an incentive for the production and marketing of natural gas which might otherwise have been flared.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. For natural gas, the freehold production tax is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas.

As at the beginning of 2009, British Columbia maintained a number of targeted royalty programs for key resource areas intended to increase the competitiveness of British Columbia's low productivity wells. These include both royalty credit and royalty reduction programs, including the following:

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 2,300 metres spud between December 1, 2003 and September 1, 2009;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

- *Coalbed Gas Royalty Reduction and Credit Program* providing a royalty reduction for coalbed gas wells with average daily production less than 17,000 m^3 as well as a royalty credit for coalbed gas wells equal to $50,000 for wells drilled on Crown land and a tax credit equal to $30,000 for wells drilled on freehold land;

- *Marginal Royalty Reduction Program* providing royalty breaks for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty breaks for low productivity shallow natural gas wells with a true vertical depth of less than 2,300 metres, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

- *Net Profit Royalty Reduction Program* providing reduced initial royalty rates to facilitate the development and commercialization of technically complex resources such as coalbed gas, tight gas, shale gas and enhanced-recovery projects, with higher royalty rates applied once capital costs have been recovered.

Oil produced from an oil well event on either Crown or freehold land and completed in a new pool discovery subsequent to June 30, 1974 may also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

On March 2, 2009, the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which allocates $120 million in royalty credits for oil and gas companies. The Infrastructure Royalty Credit Program provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. The Government of British Columbia has recently announced the same level of funding for the 2010 Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. Natural gas wells spudded within the 10-month period from September 1, 2009 to June 30, 2010 and brought on production by December 31, 2010 qualify for a 2% royalty rate for the first 12 months of production, beginning from the first month of production for the well (the "**Royalty Relief Program**"). British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. Wells spud between September 1, 2009 and June 30, 2010 may qualify for both the Royalty Relief Program and the Deep Royalty Credit Program but will only receive the benefits of one program at a time. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

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

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

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

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

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

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

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

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

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

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

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

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

Land Tenure

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

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license.

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

Environmental Regulation

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

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009, providing the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA are deemed to be legislative instruments equivalent to regulations and are binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, licenses, approvals and authorizations in order for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment. Although no regional plans have been established under the ALSA, the planning process is underway for the Lower Athabasca Region (which contains the majority of oil sands development) and the South Saskatchewan Region. While the potential impact of the regional plans established under the ALSA cannot yet be determined, it is clear that such regional plans may have a significant impact on land use in Alberta and may affect the oil and gas industry.

Climate Change Regulation

Federal

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

In anticipation of the expiry of the Kyoto Protocol in 2012, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark from December 6 to 18, 2009 (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol. 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 certain countries, including Canada, have committed to reducing their emissions individually or jointly by at least 80% by 2050, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review and implementation of its stated goals by 2016.

In response to the Copenhagen Accord, the Government of Canada has recently indicated that it will seek to achieve a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. This goal is similar to the goal expressed in previous policy documents which are discussed below.

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

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both greenhouse gases and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). Although draft regulations for the implementation of the Updated Action Plan were intended to be published in the fall of 2008 and become binding on January 1, 2010, no such regulations have been proposed to date. Further, representatives the Government of Canada have recently indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to greenhouse gas emissions regulation. The approach of the Unites States is expected to include an absolute cap on emissions combined with allowances to be used for compliance that may be partially auctioned off to regulated entities. It is also unclear whether the approach adopted by the United States will provide for the payment into a technology fund as a compliance mechanism, as is currently permitted in Alberta and by the Updated Action Plan. As a result, many provisions of the Updated Action Plan, described below, are expected to be significantly modified.

The stated goal of the Updated Action Plan, as currently drafted, is to reduce greenhouse gas emissions to 20% below 2006 levels by 2020 and 60-70% by 2050. As noted above, the goal has now been modified by the Government of Canada. The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets applied to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

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

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

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 tonnes per CO_2 equivalent for the 2010-12 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce greenhouse gas emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on July 1, 2007, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year are subject to the CCEMA. Similarly to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Existing Facilities" and "New Facilities". Existing Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2008 or that have completed 8 or more years of commercial operation. Existing Facilities were required to reduce their emissions intensity by March 31, 2008 by 12% from a baseline established by their average emissions intensity between 2003 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation subsequent to December 31, 2008, have completed less than 8 years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are also required to reduce their emissions intensity by 12% but this target is based on the emissions intensity of the facility in its third year of commercial operation and does not apply during the first 3 years of operation of the New Facility. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements beyond the 12% emissions intensity required.

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

As at year-end 2009, Baytex did not have an interest in any facilities in Alberta that emit more than 100,000 tonnes of CO_2 equivalents per year.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The initial level of the tax was set at $10 per tonne of CO_2 equivalent and rose to $15 per tonne of CO_2 equivalent on July 1, 2009. It is scheduled to further increase at a rate of $5 per tonne of CO_2 equivalent on July 1 of every year until it reaches $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and will come into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on greenhouse gas emissions. It is expected that greenhouse gas emissions restrictions will be applied to facilities emitting more than 25,000 tonnes of CO_2 equivalents per year, which will be required to meet established targets through a combination of emissions allowances issued by the Government of British Columbia and the purchase of emissions offsets generated through activities that result in a reduction in greenhouse gas emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party.

As at year-end 2009, Baytex's Cache Creek facility emitted more than 10,000 tonnes of CO_2 equivalents per year and, therefore, will be subject to reporting requirements under the Cap and Trade Act. As at year-end 2009, Baytex did not have an interest in any facilities in British Columbia that emit more than 25,000 tonnes of CO_2 equivalents per year.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate greenhouse gas emissions in the province. Although the MRGGA has only passed first reading in the Saskatchewan legislature and the specific details of the legislation have not yet been determined, it is expected that the MRGGA will adopt the goal of a 20% reduction in greenhouse gas emissions by 2020 and permit the use of technology fund contributions and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

United States

The Trust, through its subsidiary, Baytex Energy USA Ltd., also owns oil and natural gas properties and related assets in North Dakota and Wyoming in the United States. Baytex USA's oil and natural gas operations in the United States are regulated by administrative agencies under statutory provisions of the states where such operations are conducted and by certain agencies of the federal government for operations on federal leases. These statutory provisions regulate matters such as the exploration for and production of crude oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements in order to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, and the abandonment of wells. Baytex USA's operations in the United States are also subject to various conservation laws and regulations which regulate matters such as the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil and natural gas properties. In addition, state conservation laws sometimes establish maximum rates of production from crude oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the rateability or fair apportionment of production from fields and individual wells.

ADDITIONAL INFORMATION

Additional information relating to us can be found on the SEDAR website at *www.sedar.com* and on our website at *www.baytex.ab.ca.* Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our Information Circular - Proxy Statement for the annual meeting of Unitholders to be held on May 20, 2010. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2009 and the related management's discussion and analysis which are accessible on the SEDAR website at *www.sedar.com*. For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

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Fax: (403) 205-3845
Website: *www.baytex.ab.ca*

APPENDIX A

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

Management of Baytex Energy Ltd. ("**Baytex**"), on behalf of Baytex Energy Trust (the "**Trust**"), is responsible for the preparation and disclosure of information with respect to the Trust's oil and natural 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, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Trust's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the Board of Directors of Baytex, on behalf of the Trust, has:

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

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

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

The Reserves Committee of the Board of Directors of Baytex, on behalf of the Trust, has reviewed the Trust's procedures for assembling and reporting other information associated with oil and natural 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 evaluator 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. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) "*Anthony W. Marino*"
Anthony W. Marino
President and Chief Executive Officer

(signed) "*W. Derek Aylesworth*"
W. Derek Aylesworth
Chief Financial Officer

(signed) "*Dale O. Shwed*"
Dale O. Shwed
Director and Chairman of the Reserves Committee

(signed) "*John A. Brussa*"
John A. Brussa
Director and Member of the Reserves Committee

March 26, 2010

APPENDIX B

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

To the Board of Directors of Baytex Energy Ltd. ("**Baytex**"), on behalf of Baytex Energy Trust (the "**Trust**"):

1. We have evaluated the Trust's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The reserves data are the responsibility of Baytex'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 Trust evaluated by us for the year ended December 31, 2009, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the management and Board of Directors of Baytex:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue Before income taxes (10% discount rate – $ millions)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the P&NG Reserves of Baytex Energy Trust and Baytex Energy USA Ltd. (As of December 31, 2009). Preparation Date: March 19, 2010	Canada and the United States	Nil	$3,832.9	Nil	$3,832.9

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.

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

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variation should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above on March 26, 2010.

Sproule Associates Limited

(signed) "*R. Keith MacLeod*"
R. Keith MacLeod, P.Eng.
President

(signed) "*John L. Chipperfield*"
John L. Chipperfield, P.Geol.
Senior Vice-President

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

(signed) "*Peter C. Sidey*"
Peter C. Sidey, P.Eng.
Associate

(signed) "*Donald W. Woods*"
Donald W. Woods, P.Eng.
Manager, Engineering

APPENDIX C

BAYTEX ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

The Audit Committee (the "Committee") is a committee of the board of directors (the "Board") of Baytex Energy Ltd. ("Baytex") to which the Board has delegated certain of its responsibilities. The primary responsibility of the Committee is to review the interim and annual financial statements of Baytex Energy Trust (the "Trust") and to recommend their approval or otherwise to the Board. The Committee is also responsible for reviewing and recommending to the Board the appointment and compensation of the external auditors of the Trust, overseeing the work of the external auditors, including the nature and scope of the audit of the annual financial statements of the Trust, pre-approving services to be provided by the external auditors and reviewing the assessments prepared by management and the external auditors on the effectiveness of the Trust's internal controls over financial reporting.

The objectives of the Committee are to:

1. assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Trust and related matters;

2. facilitate communication between directors and the external auditors;

3. enhance the external auditors' independence;

4. increase the credibility and objectivity of financial reports; and

5. strengthen the role of the independent directors by facilitating in depth discussions between the Committee, management and the external auditors.

MEMBERSHIP OF THE COMMITTEE

1. The Committee shall be comprised of not less than three members all of whom are "independent" directors and "financially literate" (within the meaning of National Instrument 52-110 "Audit Committees"). The members of the Committee shall be appointed by the Board from time to time.

2. The Board shall appoint a Chair of the Committee, who shall be an independent director.

3. Any member of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of unitholders of the Trust following appointment as a member of the Committee.

MANDATE AND RESPONSIBILITIES OF THE COMMITTEE

1. It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting. The external auditors shall report directly to the Committee.

2. It is the responsibility of the Committee to satisfy itself on behalf of the Board with respect to the Trust's internal control systems by:

   - identifying, monitoring and mitigating business risks; and

   - ensuring compliance with legal, ethical and regulatory requirements.

3. It is a primary responsibility of the Committee to review the interim and annual financial statements of the Trust prior to their submission to the Board for approval. The review process should include, without limitation:

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;

   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;

   - reviewing accounting treatment of unusual or non-recurring transactions;

   - ascertaining compliance with covenants under loan agreements;

   - reviewing disclosure requirements for commitments and contingencies;

   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

   - reviewing unresolved differences between management and the external auditors;

   - obtaining explanations of significant variances with comparative reporting periods; and

   - determining through inquiry if there are any related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

4. The Committee is to review all public disclosure of audited or unaudited financial information by the Trust before its release (and, if applicable, prior to its submission to the Board for approval), including the interim and annual financial statements of the Trust, management's discussion and analysis of results of operations and financial condition, press releases and the annual information form. The Committee must be satisfied that adequate procedures are in place for the review of the Trust's disclosure of financial information and shall periodically assess the accuracy of those procedures.

5. With respect to the external auditors of the Trust, the Committee shall:

   - recommend to the Board the appointment of the external auditors, including the terms of their engagement for the integrated audit;

   - review and approve any other services to be provided by the external auditors (including the fee for such services); and

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

6. Review with the external auditors (and the internal auditor if one is appointed by the Trust) their assessment of the internal controls of the Trust, 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 the audit and, upon completion of the audit, their reports upon the financial statements of the Trust and its subsidiaries.

7. The Committee must pre-approve all services to be provided to the Trust or its subsidiaries by the external auditors. In pre-approving any service, the Committee shall consider the impact that the provision of such service may have on the external auditors' independence. The Committee may delegate to one or more of its members the authority to pre-approve services, provided that the member report to the Committee at the next scheduled meeting such pre-approval and the member comply with such other procedures as may be established by the Committee from time to time.

8. The Committee shall review the risk management policies and procedures of the Trust (i.e., hedging, litigation and insurance).

9. The Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls or auditing matters and the confidential, anonymous submission by employees of the Trust's subsidiary entities of concerns regarding questionable accounting or auditing matters.

10. The Committee shall review and approve the Trust's hiring policies regarding employees and former employees of the present and former external auditors of the Trust.

11. The Committee shall have the authority to investigate any financial activity of the Trust. All employees of the Trust's subsidiary entities are to cooperate as requested by the Committee.

12. The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board.

13. The Committee shall meet with the external auditors at least four times per year (in connection with their review of the interim and annual financial statements) and at such other times as the external auditors and the Committee consider appropriate.

MEETINGS AND ADMINISTRATIVE MATTERS

1. At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the chairman of the meeting shall be entitled to a second or casting vote.

2. The Chair shall preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee present shall designate from among the members present a chairman for purposes of the meeting.

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

4. Meetings of the Committee should be scheduled to take place at least four times per year and at such other times as the Chair may determine.

5. Agendas, approved by the Chair, shall be circulated to Committee members along with background information on a timely basis prior to the Committee meetings.

6. The Committee may invite those officers, directors and employees of the Trust's subsidiary entities as it may see fit from time to time to attend at meetings of the Committee and assist thereat in the discussion and consideration of the matters being considered by the Committee, provided that the Chief Financial Officer of the Corporation shall attend all meetings of the Committee, unless otherwise excused from all or part of any such meeting by the chairman of the meeting.

7. Minutes of the Committee's meetings will be recorded and maintained and made available to any director who is not a member of the Committee upon request.

8. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation.

9. Any issues arising from the Committee's meetings that bear on the relationship between the Board and management should be communicated to the Executive Chairman or the Lead Independent Director, as applicable, by the Committee Chair.

Approved by the Board of Directors on May 20, 2009