BAYTEX ENERGY TRUST

ANNUAL INFORMATION FORM

2008

MARCH 26, 2009

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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 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.

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 dated March 4, 2009 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Trust and Baytex Energy USA Ltd. (As of December 31, 2008*)".

Securities and Other Terms

Convertible Debentures means our 6.50% convertible unsecured subordinated debentures issued on June 6, 2005.

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.

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 subsidiaries or affiliates to us from time to time.

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

NPI means the net profit interest in the petroleum substances owned by Baytex held by us.

NPI Agreement means the amended and restated net profit interest agreement between us and Baytex made as of September 2, 2003 providing for the creation of the NPI.

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 us 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	6.290
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
Gigajoules	MMbtu	0.950

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. 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.

Specifically, this Annual Information Form contains forward-looking statements relating to: the taxation of income trusts; potential changes to our business form; oil and gas prices; the demand for and supply of crude oil and natural gas; our distribution practice; the portion of our cash flow 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 cash flow from operations; our ability to grow our reserve base and add to production levels through exploration and development activities complimented by strategic acquisitions; the size of our petroleum and natural gas reserves; development plans for our properties; our heavy oil resource play at Seal, including 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, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, operating costs and the resource potential of our undeveloped land; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates and average recoveries per well; rates of production for 2009; 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: oil 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: fluctuations in market prices for oil and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; uncertainties associated with estimating oil and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and gas operations; changes in royalty rates and incentive programs relating to the oil and gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; 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 Cash Flow from Operations

This Annual Information Form contains references to cash flow from operations derived from cash provided by operating activities before changes in non-cash operating working capital, asset retirement expenditures and decrease in deferred charges and other assets. Cash flow 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. Cash flow 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 Financial Condition and Results of Operations*" which includes a definition of "cash flow from operations" and reconciliation to cash provided by 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 foreign private issuer, we are only required to comply with three of the NYSE rules: 1) have an audit committee that satisfies the requirements of the *United States Securities Exchange Act of 1934*; 2) the 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) 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 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, 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.

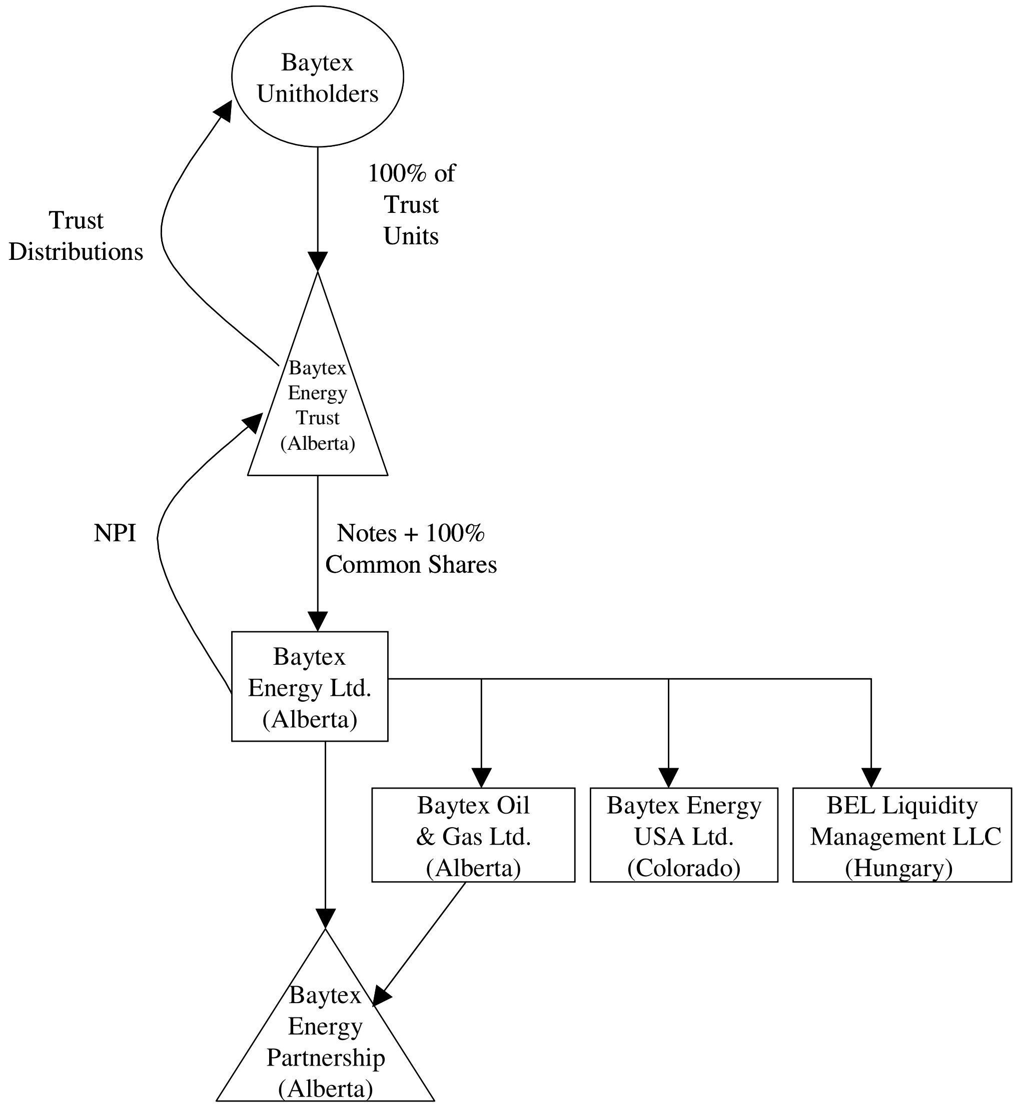
Inter-Corporate Relationships

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 Energy 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.



Notes:

(1) Unitholders own 100 percent of our Trust Units.

(2) Cash distributions are made on a monthly basis to Unitholders based upon our cash flow. Our primary sources of cash flow are NPI payments from Baytex 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

In 2007, the Federal Government introduced and passed into law amendments to the Tax Act that will result in the taxation of distributions by certain specified investment flow-through trust entities (a "**SIFT**"), such as us, commencing January 1, 2011 (provided the SIFT only experiences "normal growth" and no "undue expansion" before then) (the "**SIFT Rules**"). The SIFT Rules provide that the tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5% in 2011 and 15% in 2012) plus the provincial SIFT tax rate. The provincial SIFT tax rate is based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. For purposes of calculating this component of the tax, the general corporate taxable income allocation formula will be used. Specifically, our taxable distributions will be allocated to provinces by taking half of the aggregate of (i) that proportion of our taxable distributions for the year that our wages and salaries in the province are of our total wages and salaries in Canada and (ii) that proportion of our taxable distributions for the year that our gross revenues in the province are of our total gross revenues in Canada. Taxable distributions that are not allocated to any province will be subject to a 10% tax rate. We would be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10%, which will result in an effective tax rate of 26.5% in 2011 and 25% in 2012.

Generally, there will be a transition period for an existing SIFT and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of its issued and outstanding publicly-traded trust units, and not any convertible debt, options or other interests convertible into or exchangeable for trust units). Those safe harbour limits are 40 percent for the period from November 1, 2006 to December 31, 2007 and 20 percent each for calendar 2008, 2009 and 2010. On December 4, 2008, the Minister of Finance announced changes to the safe harbour limits to allow a SIFT to accelerate the utilization of the SIFT annual safe harbour limit for each of 2009 and 2010 so that the safe harbour limits for 2009 and 2010 are available on and after December 4, 2008. This change does not alter the maximum permitted expansion threshold for a SIFT, but it allows a SIFT to use its normal growth room remaining as of December 4, 2008 in a single year, rather than staging a portion of the normal growth room over the 2009 and 2010 years. These limits are cumulative, so that any unused limit for a period carries over into the subsequent period. For us, the growth limits are approximately $730 million for 2006/2007 and an additional approximately $365 million for each of 2008, 2009 and 2010 with any unused amount carrying forward to the next year. We did not issue equity in excess of the safe harbour limits during 2006/2007 or 2008. As at December 31, 2008, we had unused safe harbour limit of $596.6 million that was carried forward, resulting in a safe harbour limit of $1,326.6 million for 2009/2010.

On July 14, 2008, Finance announced proposed amendments to the Tax Act including technical amendments to clarify certain aspects of the SIFT Rules and to provide rules to facilitate the conversion of existing SIFT trusts into corporations on a tax-deferred basis (the "**Conversion Rules**"). The Conversion Rules address many of the principal substantive and administrative issues that arise when structuring a corporate conversion of an income trust under the Tax Act. The Conversion Rules contemplate two alternatives for the conversion of a publicly-traded income trust into a taxable Canadian corporation and the winding-up of the trust's underlying structure. The first alternative involves the winding-up of the trust into a taxable Canadian corporation whereas the second approach involves the distribution by the publicly-traded income trust of shares of an underlying taxable Canadian corporation to its unitholders.

Subsequent to the year end, the Federal Government introduced draft tax legislation which included the above mentioned measures as part of Canada's Economic Action Plan. This legislation received Royal Assent on March 12, 2009, and was therefore passed into law. We continue to review the impact of the future taxation of distributions on our business strategy but at this time have made no decision as to the ultimate legal form under which we will operate post 2010.

Notwithstanding the SIFT Rules, cash flow earned by a trust and not distributed has always been and continues to form part of taxable income at the trust level, which may result in cash taxes being paid if there are not sufficient tax pool claims and deductions obtained upon incurring capital expenditures or acquiring assets.

For more information, see "*Risk Factors – Risks Related 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*".

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On September 2, 2003, we completed a plan of arrangement under the *Business Corporations Act* (Alberta) involving Baytex, Crew, Baytex Acquisition Corp., Baytex ExchangeCo, Baytex Resources Ltd., Baytex Exploration Ltd. and us pursuant to which 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. Coincident with the plan of arrangement becoming effective, certain of Baytex's exploration assets were acquired by Crew, and the common shares of Crew were distributed to the former holders of Baytex common shares on the basis of one-third of a common share of Crew for each such share held.

On December 12, 2003, we completed a public offering of 6,500,000 Trust Units at a price of $10.00 per Trust Unit for gross proceeds of $65,000,000. The net proceeds of the offering were used to fund our ongoing capital expenditure and acquisition program.

On September 22, 2004, we completed the acquisition of a Calgary based private oil and gas company, for cash consideration of $109 million before adjustments. The acquisition was financed with Baytex's credit facilities and added approximately 3,000 boe/d of 65 percent gas weighted production. The assets acquired were located in two geographically focused areas of southern Alberta, Sedalia/Garden Plains and Turin/Parkland, and also included 110,000 net acres of undeveloped land. Production from this acquisition represented approximately 9.3 percent of our then existing production. Ninety-five percent of the production was from operated, high working interest properties with ownership and control of most key facilities and infrastructure within the operating areas. This acquisition added a significant inventory of drilling opportunities including low risk development and medium risk exploration to our light oil and natural gas portfolio. Opportunities also existed for re-entries, recompletions, tie-ins and workovers. Subsequent to the acquisition, the private company was amalgamated into Baytex.

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.

On December 20, 2004, we completed a public offering of 3,600,000 Trust Units at a price of $12.80 per Trust Unit for gross proceeds of $46,080,000. The net proceeds of the offering were used to repay outstanding bank indebtedness.

On December 22, 2004, we completed the acquisition of certain strategic oil and natural gas interests in the West Stoddart area of northeast British Columbia for $90 million before adjustments. The assets acquired consisted of approximately 3,300 boe/d of primarily high netback liquids-rich natural gas production comprised of 10.0 MMcf/d of natural gas, 1,300 bbl/d of NGL and 330 bbl/d of light oil. Production from this acquisition represented approximately 9.6 percent of our then existing production. Production was mainly from three year-round access properties near Fort St. John, British Columbia (West Stoddart, North Cache and Cache Creek). The primary producing zones were the Doig, Halfway, Charlie Lake, Baldonnel and Cretaceous zones. The assets represented a new core area for us and were 100 percent operated with an average working interest of 91 percent. The acquisition also included an identified project inventory, including drilling, recompletions, fracture stimulation and well optimizations, and approximately 17,000 net acres of undeveloped land contiguous to the principal producing properties.

On June 6, 2005, we issued $100 million principal amount of Convertible Debentures for net proceeds of $95.8 million. 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 net proceeds from the issue of the Convertible Debentures were used to reduce outstanding bank indebtedness.

On September 30, 2005, we completed the acquisition of certain heavy oil producing properties in the Celtic area in Saskatchewan for $69 million. The assets acquired consisted of 3,350 bbl/d of heavy oil (13º - 15º API) and 0.9 MMcf/d of natural gas. Production from this acquisition represented approximately 10 percent of our then existing production. The assets acquired also included approximately 7,500 net acres of undeveloped land. The Celtic properties are situated approximately 30 miles east of Lloydminster and are adjacent to our Tangleflags property. The expanded Celtic/Tangleflags operating region resulted in improved economies of scale and allowed for better control over costs. The acquisition included in excess of 100 opportunities for development drilling and recompletions for additional primary (cold) heavy oil production and natural gas production which added immediate low-cost development inventory. The acquisition also included 1,750 bbl/d of steam assisted gravity drainage ("**SAGD**") production. As part of this transaction, Baytex entered into a price-sharing arrangement and a net profits agreement for future SAGD development with the vendor with respect to the assets acquired.

On December 30, 2005, we sold the recently acquired SAGD assets in the Celtic area of Saskatchewan for $45.3 million. Production at that time from the SAGD assets was approximately 2,000 bbl/d of heavy oil.

During 2006, we did not complete any significant financings, acquisitions or dispositions.

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 one of the strongest infrastructure positions in the area, which contributed to our high degree of operational control of the area, and 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 to maintain production rates. In addition to the primarily non-operated producing assets, 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. 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.

Significant Acquisitions

During the year ended December 31, 2008, we did not complete any acquisitions for which disclosure was required under Part 8 of National Instrument 51-102.

Trends

Natural gas and crude oil prices are volatile and subject to a number of external factors. Natural gas is a commodity primarily influenced by factors within North America. A tight supply-demand balance for natural gas causes significant elasticity in pricing, whereas higher than average storage levels tend to depress natural gas pricing. Drilling activity, weather, fuel switching and demand for electrical generation are all factors that affect the supply-demand balance. Changes to any of these or other factors create price volatility. Crude oil is influenced by the world economy, OPEC's ability to adjust supply to world demand and weather. For the first half of 2008, crude oil prices were kept high by political events causing disruptions in the supply of oil and concern over potential supply disruptions triggered by unrest in the Middle East and more recently has been impacted by weather and increased storage levels. Political events trigger large fluctuations in price levels. The Canadian/U.S. currency exchange rate also influences commodity prices received by Canadian producers as oil and natural gas production is ultimately priced in U.S. dollars. The Canadian dollar generally follows the trend in commodity prices. During 2007, the strengthening of the Canadian dollar somewhat mitigated the economic benefit of higher prices on Canadian oil and gas producers. However, in late 2008 the weakening of the Canadian dollar partially mitigated the effect of lower prices on Canadian oil and gas producers.

The impact on the oil and gas industry from commodity price volatility is significant. During period of high prices, producers generate sufficient cash flows to conduct active exploration programs without external capital. Increased commodity prices frequently translate into very busy periods for service suppliers triggering premium costs for their services. Purchasing land and properties similarly increase in price during these periods. During low commodity price periods, acquisition costs drop, as do internally generated funds to spend on exploration and development activities. With decreased demand, the prices charged by the various service suppliers also decline.

The efforts of energy trusts to replace annual production declines have been a factor resulting in high levels of competition for the acquisition of oil and natural gas properties and related assets. This increased competition has raised valuation parameters for corporate and asset acquisitions. Those trusts with opportunities to replace production economically through internal development drilling may be in a favourable position relative to those more exposed to replacing production through acquisitions.

Another trend currently affecting the oil and gas industry is the impact on capital markets caused by investor uncertainty in the North American economy. The capital market volatility in Canada has also been affected by uncertainties surrounding the economic impact that various environmental initiatives will have on the sector and, in more recent times, by the SIFT Rules. See "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks Relating to our Revenues – We may be impacted by recent federal tax changes for income trusts and corporations*".

RISK FACTORS

You should carefully consider the following matters, 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.

Information contained in this Annual Information Form 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*".

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"*.

Risks Relating to our Revenues

Our business depends on volatile oil and gas prices

The operational results and financial condition of our operating entities and therefore the amounts paid to us will be dependent on the prices received for oil and natural gas production. The prices for oil and natural gas may be volatile and subject to fluctuation. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States and Canada, the actions of OPEC, governmental regulation, and political stability in the Middle East and elsewhere, 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 our carrying value of our proved and probable reserves, borrowing capacity, revenues, profitability and cash flow from operations. Any movement in oil and natural gas prices could have an effect on our financial condition and therefore on the amounts to be distributed to our Unitholders.

We may manage the risk associated with changes in commodity prices by entering into oil or natural gas price hedges. If we hedge our commodity price exposure, we will forego the benefits we would otherwise experience if commodity prices were to increase. In addition, commodity hedging activities could expose us to losses. As at December 31, 2008, our balance sheet reflected $83.4 million of unrealized gains resulting from hedges to protect our commodity risk exposure. To the extent that we engage in risk management activities related to commodity prices, we will be subject to credit risks associated with counterparties with which we contract.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisition 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. See "*– Risks Relating to our Operations – Project delays may delay expected revenues from operations*" and "*– Risks Associated with Acquisitions and Dispositions – We may not realize anticipated benefits of acquisitions and dispositions or manage our growth*".

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

World oil prices are quoted in Unites 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. A material increase in the value of the Canadian dollar may negatively impact our net production revenue.

In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar negatively impact our production revenues which may affect future distributions. Future Canadian/United States exchange rates could accordingly impact the future value of our reserves as determined by our independent evaluator.

From time to time we may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, we will not benefit from the fluctuating exchange rate. As at December 31, 2008, our balance sheet reflected $2.3 million of unrealized gains resulting from hedges to protect our currency risk exposure. To the extent that we engage in risk management activities related to foreign exchange rates, we will be subject to credit risk associated with counterparties with which we contract.

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, as well as impact the market price of the Trust Units.

The global financial crisis could adversely affect us

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively affected company and trust valuations and will impact the performance of the global economy going forward.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

We may be subject to refinancing risk and increased debt service charges

We currently have a $485 million syndicated credit facility. At December 31, 2008, we had approximately $183 million of unused credit available under our credit facility. In normal circumstances, borrowers such as us rely on the fact that the banks will honour their contractual commitments to fund draws as required. In today's economic environmental there is a risk that one or more of the banks included in our syndicate may not honour draws requested by us and thereby effect our ability to maintain our capital expenditure programs. Our lenders review the credit facility each year and determine if they will extend for another year. The credit facility matures on July 1, 2009 and, although we have no reason to believe that we will be unable to extend the credit facility, in the event that the facility is not extended before July 1, 2009, indebtedness under the facility will be repayable at that date. There is also a risk that the credit facility will not be renewed for the same amount or on the same terms. 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 the NPI and interest on the Notes and net income. Furthermore, any of these events could affect our ability to fund ongoing operations.

We currently have US$179.7 million of 9.625% senior subordinated notes due July 15, 2010 and US$247,000 of 10.5% senior subordinated notes due February 15, 2011. We also have $10.4 million of Convertible Debentures outstanding which are convertible at the option of the holder at any time into fully paid Trust Units at a conversion price of $14.75 per unit and mature on December 31, 2010. We intend to partially fund these debt maturities with our existing credit facility; however, we are subject to limitations on the amounts we can draw on our credit facility in order to repay the senior subordinated notes and the Convertible Debentures. The maximum amount we may draw for any such repayments is 20% of the amount of our credit facility and this amount is reduced to nil if the amount drawn on our credit facility exceeds 75% of the amount of such facility. 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 facility. In the event that we do not comply with covenants under the credit facility, 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 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 lender may foreclose on or sell our working interests in our properties.

From time to time we may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. We are not restricted in the amount of indebtedness that we may incur. 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.

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 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 capital expenditure program, or that we will be able to obtain additional funds.

The weakened global economic situation may affect our access to capital markets

Commercial credit market disruptions have resulted in a tightening of credit markets worldwide. Liquidity in the global credit market has been severely contracted by these market disruptions, making it costly to obtain new lines of credit or to refinance existing debt. The effects of these disruptions are widespread and difficult to quantify, and it is impossible to predict when the global credit market will improve or when the credit contraction will stop. As a result of the ongoing credit market turmoil, we will have restricted access to capital and increased borrowing costs. Although our business and asset base have not changed, the lending capacity of all financial institutions has diminished and risk premiums have increased. As future capital expenditures will be financed out of cash flow 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 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 cash flow generated from operations, together with the existing bank facilities, will be sufficient to substantially finance current operations, distributions to Unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of distribution is also discretionary, and we have the ability to modify distribution levels should cash flow from operations be negatively impacted by a reduction in commodity prices. However, if cash flow 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.

The weakened global economy may expose us to increased third party credit risk

We are exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. We manage this credit risk by entering into sales contracts with only creditworthy entities and reviewing its 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.

We may be impacted by recent federal tax changes for income trusts and corporations

The SIFT Rules 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. The SIFT Rules will result 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 the amount of cash flow from operations available for distributions to Unitholders.

Generally, there will be a four year transition period for an existing SIFT entity, such as us, and the tax under the SIFT Rules will not apply until January 1, 2011. However, the SIFT Rules provide that there are circumstances under which an existing trust may lose its transitional relief before 2011, including where the "normal growth" of a trust existing on October 31, 2006 is exceeded.

While the normal growth restrictions are such that it is unlikely they would affect our ability to raise the capital required to maintain and grow our existing operations in the ordinary course during the transition period, they could adversely affect the cost of raising capital and our ability to undertake more significant acquisitions. The SIFT tax has reduced the value of the Trust Units, which has increased the cost to us of raising capital in the public capital markets. In addition, management believes that the SIFT Rules: (a) substantially eliminate the competitive advantage that we and other Canadian energy trusts enjoyed relative to our corporate peers in raising capital in a tax-efficient manner, and (b) places us and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships which will continue to not be subject to entity level taxation. The new legislation also makes 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 Rules.

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 affects us and our Unitholders. See "— *Risks Associated with Government Regulation – Our revenues are affected by changes in regulations*".

We may have delays in cash receipt

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.

We are affected by political events

The marketability and price of oil and natural gas that may be acquired or discovered by us are and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of our cash flow from operations.

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 object of a terrorist attack, it could have a material adverse effect on our financial condition. We do not carry insurance to protect against potential losses from acts of terrorism.

Risks Relating to our Operations

Exploitation and development may not result in commercially productive reserves

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by us. 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.

Distributions may be affected by operating costs and production declines

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. Electricity, chemicals, supplies, reclamation and abandonment and labour costs are a few of our operating costs that are susceptible to material fluctuation.

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

Our business involves numerous operating hazards, and we are not fully insured against all of them

Our operations are subject to all of the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, sour gas releases and spills, blow-outs, craterings and fires, all of 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. In particular, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability. In accordance with industry practice, we are not fully insured against all of these risks, nor are all such risks insurable. Although we maintain liability insurance policies in place, in such amounts as we consider adequate to address certain of these risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, 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. The payment of such uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, could have a material adverse effect on our financial position, results of operations or prospects and will reduce the income receivable by us under the NPI.

Project delays may delay expected revenues from operations

We manage a variety of small and large projects in the conduct of our business. Project delays may delay 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;

- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we may 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.

Drilling equipment availability and access may be restricted

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. To the extent we are not the operator of our oil and gas properties, we will be dependent on such operators for the timing of activities related to such properties and will be largely unable to direct or control the activities of the operators.

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.

Reserves figures are only estimates and may require revision

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.

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources and the future cash flows attributed to such reserves, including many factors beyond our control. In general, estimates of economically recoverable oil 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 oil 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. 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.

Estimates of proved reserves that may be developed and produced in the future 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.

In accordance with applicable securities laws, Sproule has used forecast price and cost estimates in calculating reserve quantities included in this Annual Information Form. Actual future net cash flows will be affected by other factors such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from reserves will vary from the reserves estimates contained in the Sproule Report summarized in this Annual Information Form, and such variations could be material. 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 engineering reports summarized in this Annual Information Form.

The reserves and recovery information contained in the Sproule Report are only estimates and the actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by Sproule. 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 cash flows for our reserves would be reduced and the reduction could be significant.

Our reserves may become depleted

We conduct limited exploration activities for oil and natural gas reserves. Instead, we add to our oil and natural gas reserves primarily through development and acquisitions. As a result, future oil and natural gas reserves are highly dependent on our success in exploiting existing properties and acquiring additional reserves. We also distribute a significant proportion of our cash flow 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 oil and natural gas reserves may be impaired. To the extent that we use cash flow from operations to finance capital expenditures or property acquisitions, the level of cash flow from operations available for distribution to Unitholders will be reduced. Additionally, we cannot guarantee that we will be successful in developing additional reserves or acquiring additional reserves on terms that meet our investment objectives. Without these reserves additions, our reserves will deplete and as a consequence, either production from, or the average reserves life of, our properties will decline. These events may result in a reduction in the value of Trust Units and in a reduction in cash flow from operations available for distributions to Unitholders.

Distributions may be affected by capital expenditures

The timing and amount of capital expenditures will directly affect the amount of cash flow from operations available for distribution to Unitholders. Distributions may be reduced, or even eliminated, at times when significant capital or other expenditures are made. In addition, 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 oil and natural gas reserves will be impaired.

We are dependent on our operators and other third parties to produce and market our property

Other companies operate some of the assets in which we have an interest. 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. To the extent the operator fails to perform these functions properly, revenue may be reduced. As a result, we have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. 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.

We face competition from competitors with greater resources

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 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 is difficult to acquire reserves on beneficial terms. We also compete for reserves acquisitions and undeveloped land with a substantial number of other oil and gas companies, many of which 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 the execution of our annual capital development program. The inability to hire and retain skilled personnel could adversely impact certain of our operational and financial results.

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 Associated with Government Regulation

We are affected by federal and provincial laws and regulations relating to the environment

Nearly all aspects of our operations are subject to a variety of federal, provincial and local laws and regulations, including laws and regulations relating to the protection of the environment and the operation, maintenance, abandonment and reclamation of sites and wells, which may be amended from time to time to impose higher standards and potentially more costly obligations on us. Environmental assessments, permits and regulatory approvals are required before initiating most new major projects or undertaking significant changes to existing operations. 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. 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. We provide for the necessary amounts in our annual capital budget for the purpose of funding our currently estimated future environmental and reclamation obligations based on our current knowledge.

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 and prospects. Environmental legislation is evolving in a manner expected to 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. There can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations. See "*Industry Conditions — Environmental Regulation*".

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases which will require us to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*. The direct or indirect costs of these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

Our management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions, 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 or taxes based upon emissions. There has been much public debate with respect to Canada's ability to meet emission targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined 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 the impact on us and our business, financial condition, results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

Our revenues are affected by changes in regulations

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. See "*Industry Conditions*" and "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*". Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase our costs, any of which may have a material adverse effect on our business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, we will require licenses 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.

Our status as a mutual fund trust may be changed or affected by changes in legislation

Income tax laws, or other laws or government incentive programs relating to the oil and gas industry, such as the treatment of mutual fund trusts and resource taxation, may in the future be changed or interpreted in a manner that adversely affects us and our Unitholders. Tax authorities having jurisdiction over us or the Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practises to our detriment or the detriment of our Unitholders**.**

There can be no assurance that the treatment of mutual fund trusts will not be changed in a manner adversely affecting Unitholders. If we cease to qualify as a "mutual fund trust" under the Tax Act, the Trust Units will cease to be qualified investments 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**").

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. We may not be able to take steps necessary to ensure that we maintain our mutual fund trust status. Even if we are successful in taking such measures, these measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada (as defined in the Tax Act). There can be no assurance that such circumstances would not have a material adverse affect on the market price of the Trust Units.

Should the status of us 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 royalties 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 if we ceased to be a mutual fund trust.

- 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 would cease to be a qualified investment for RRSPs, RESPs, DPSPs, RDSPs, TFSAs and 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*".

We have non-resident ownership restrictions of our Trust Units

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 us, 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*" and "*Risk Factors – Risks Associated with Government Regulation – Our status as a mutual fund trust may be changed or affected by changes in legislation*".

Risks Associated with Acquisitions and Expansion

We may not realize anticipated benefits of acquisitions and dispositions or manage our 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 those of our operations. The integration of an acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that 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.

Acquisitions of resource issuers and resource assets will be based in large part upon engineering and economic assessments made by independent engineers. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies, which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. In particular, the prices of and markets for resource products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty, which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based upon reports by a firm of independent engineers other than the firm that we use for our year-end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm we use. Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat our claim which could result in a reduction of the revenue received by us.

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 impact on our business, operations and prospects.

We may expand our operations

Our operations and expertise are currently primarily focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin, although we have recently expanded into 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 future operational and financial conditions.

Management Risks

We are dependant on Baytex management

We are a limited purpose trust and are entirely dependent upon the operations and assets of Baytex through our ownership, directly and indirectly, of securities of Baytex, including the common shares of Baytex, the Notes and the NPI. Accordingly, our ability to pay distributions to Unitholders is dependent upon the ability of Baytex to meet its interest, principal, dividend and other distribution obligations on the securities of Baytex and to pay the NPI. Baytex's income is received from the production of oil and natural gas from its Canadian 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 Baytex's resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, the ability of Baytex to meet its obligations to us and our ability to pay distributions to Unitholders may be adversely affected.

Our directors and officers may have conflicts

Our directors and officers are engaged in and will continue to engage in other activities in the oil and natural gas industry and, as a result of these and other activities, they may become subject to conflicts of interest. 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 under the *Business Corporations Act*

(Alberta). To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

As at the date hereof, we are not aware of any existing or potential material conflicts of interest between us and a director or officer of ours.

Capital Risks

Our net asset value will vary from time to time

Our net asset value from time to time will vary dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Trust Units from time to time is also determined by a number of factors which are beyond the control of management and such trading prices may be greater or less than our net asset value.

We may issue additional Trust Units

In the normal course of making capital investments to maintain and expand our oil and gas reserves, additional Trust Units may be issued from treasury which may result in a decline in production and reserves per Trust Unit. Additionally, from time to time we may issue Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. We may also make future acquisitions or enter into financings or other transactions involving the issuance of securities which may be dilutive. To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand our oil and gas reserves will be impaired. Management believes that the SIFT Rules will substantially eliminate the competitive advantage that we and other energy trusts have enjoyed relative to our industry competitors in raising capital in a tax-efficient manner. See "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – Risks Relating to our Revenues – We may be impacted by recent federal tax changes for income trusts and corporations*". To the extent that we are required to use cash flow from operations to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash flow from operations available for distribution to Unitholders will be reduced.

Risks Associated with our Structure as a Trust

Our Trust Units are not shares

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 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), 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 of our operating entities. 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 also unlike conventional debt instruments in that there is no principal amount owing to Unitholders. The Trust Units will have minimal 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.

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.

Our Trust Units have a limited redemption right

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 investments. Notes or Redemption Notes (as defined in the Trust Indenture) which may be distributed *in specie* to Unitholders in connection with redemption will not be listed on any stock exchange and no established market is expected to develop for such Notes or Redemption Notes. In addition, there may be resale restrictions imposed by law upon the recipients of the securities pursuant to the redemption right. Cash redemptions are subject to limitations. See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Redemption Right*".

Trust Units will have no value when reserves from our properties can no longer be economically produced and, as a result, cash 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. Consequently, distributions represent a blend of *return of* Unitholders initial investment and a *return on* Unitholders initial investment.

Our Unitholders may not have limited liability

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. 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.

We allocate all of our income

Pursuant to the provisions of the Trust Indenture, all income earned by us in a fiscal year, not previously distributed in that fiscal year, must be distributed to Unitholders of record on December 31. This excess income, if any, will be allocated to Unitholders of record at December 31 but the right to receive this income, if the amount is not determined and declared payable at December 31, will trade with the Trust Units until determined and declared payable in accordance with the rules of the Toronto Stock Exchange. To the extent that a Unitholder trades Trust Units in this period, they will be allocated such income but will dispose of their right to receive such distribution.

Our expenses and other deductions may be challenged by taxing authorities

Generally, oil and gas income trusts involve significant amounts of inter-company debt, royalties or similar instruments, generating substantial interest expense or other deductions which serve to reduce taxable income and income tax payable. There can be no assurance that the taxation authorities will not seek to challenge the amount of our interest expense and other deductions. If such a challenge were to succeed against us, it could materially adversely affect the amount of cash flow received by us and, therefore, may reduce distributions to our unitholders.

Certain Risks for United States and other non-resident Unitholders

The ability of United States and other non-resident investors to enforce civil remedies may be limited

We are a trust organized under the laws of Alberta, Canada, and our principal place of business is in Canada. All of the directors and officers of Baytex are residents of Canada and most of the experts who provide services to us (such as our auditors and our independent reserve engineers) are residents of Canada, and all or a substantial portion of their assets and our assets are located within Canada. As a result, it may be difficult for investors in the United States or other non-Canadian jurisdictions (a "**Foreign Jurisdiction**") to effect service of process within such Foreign Jurisdiction upon such directors, officers and representatives of experts who are not residents of the Foreign Jurisdiction or to enforce against them judgments of courts of the applicable Foreign Jurisdiction based upon civil liability under the securities laws of such Foreign Jurisdiction, including United States federal securities laws or the securities laws of any state within the United States. In particular, there is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or the 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; however, we also follow the United States practice of separately reporting these 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, and we do not estimate our reserves using prices and costs held constant at the effective date of the reserve report.

We include in this Annual Information Form estimates of our proved and proved plus probable reserves. The SEC generally prohibits the inclusion of estimates of probable reserves in filings made with it. This prohibition does not apply to us because we are a Canadian foreign private issuer.

United States and other non-resident Unitholders may be subject to additional taxation

The Tax Act and the tax treaties between Canada and other countries may impact withholding or other taxes on the cash distributions or other property paid by us to Unitholders who are not residents of Canada, and these taxes may change from time to time. Since January 1, 2005, a 15 percent withholding tax is applied to distributions made to non-resident unitholders.

Non-resident Unitholders are subject to foreign exchange risk

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 weakens 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, making 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 net profits interests, royalties and other interests. Baytex and our operating subsidiaries carry on the business of acquiring and holding interests in oil and natural gas properties and assets related thereto. Cash flow from these properties is flowed from our operating subsidiaries to us by way of interest payments and principal repayments on the Notes and through NPI payments.

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 the 15th day (or if such date is not a business day, on the next business 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 available cash flow 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 Baytex's credit facilities or upon a material borrowing base shortfall or default.

Baytex's senior subordinated notes also contain certain limitations on maximum cumulative distributions. Restricted payments include the declaration or payment of any dividend or distribution to us and the payment of interest or principal on subordinated debt owed to us. Baytex is restricted from making any restricted payments, including distributions to us, if a default or event of default under the note indenture governing the senior subordinated notes has occurred and is continuing. If no such default or event of default has occurred and is continuing, Baytex may make a distribution to us provided at the time either (A) (i) its ratio of consolidated debt to consolidated cash flow from operations does not exceed 3 to 1, (ii) its fixed charge coverage ratio for the preceding four fiscal quarters is greater than 2.5 to 1 and (iii) the aggregate of all restricted payments declared or made after July 9, 2003 does not exceed the sum of 80 percent of the consolidated cash flow from operations accrued on a cumulative basis since July

9, 2003 plus the net cash proceeds received by us from the issuance of deeply subordinated intercompany debt or the receipt of capital contributions from the Trust plus net proceeds received by Baytex from the issuance of and upon conversion of debt and other securities or (B) the aggregate amount of all restricted payments declared or made after July 9, 2003 does not exceed the sum of permitted restricted payments not previously made plus US$30,000,000.

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 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

We are a party to the NPI Agreement with Baytex pursuant to which we have the right to receive a NPI on petroleum and natural gas rights held by Baytex from time to time. Pursuant to the terms of the NPI Agreement, we are entitled to a payment from Baytex for each month equal to the amount by which 99 percent of the gross proceeds from the sale of production attributable to such property interests for such month exceed 99 percent of certain deductible costs for such period. Baytex is entitled to set off amounts reimbursable to it against NPI payments payable by Baytex. 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, 2008. The statement is effective as of December 31, 2008 and the preparation date of the statement by Sproule is March 4, 2009. 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, 2008 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, 2008
FORECAST PRICES AND COSTS

CANADA

	LIGHT AND MEDIUM OIL		HEAVY OIL		BITUMEN	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED:						
Developed Producing	6,703.4	4,723.5	28,430.2	23,487.2	-	-
Developed Non-Producing	705.0	507.1	20,922.5	17,139.5	-	-
Undeveloped	3,673.5	2,823.9	37,584.1	30,712.2	-	-
TOTAL PROVED	11,081.9	8,054.5	86,936.9	71,338.9	-	-
PROBABLE	5,461.8	3,592.3	36,652.9	29,950.5	2,463.7	2,082.8
TOTAL PROVED PLUS PROBABLE	16,543.7	11,646.9	123,589.8	101,289.3	2,463.7	2,082.8

	NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:						
Developed Producing	87,540.0	69,886.0	2,756.0	2,100.2	52,479.7	41,958.6
Developed Non-Producing	16,606.9	11,355.8	594.2	432.8	24,989.5	19,972.0
Undeveloped	13,813.1	11,126.8	375.4	274.5	43,935.1	35,665.1
TOTAL PROVED	117,960.0	92,368.6	3,725.5	2,807.5	121,404.4	97,595.7
PROBABLE	55,016.0	40,778.9	1,846.3	1,381.2	55,593.8	43,803.3
TOTAL PROVED PLUS PROBABLE	172,976.0	133,147.5	5,571.8	4,188.7	176,998.2	141,398.9

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)
PROVED:						
Developed Producing	1,190.8	1,090.6	-	-	-	-
Developed Non-Producing	196.3	159.1	-	-	-	-
Undeveloped	2,560.6	2,074.3	-	-	-	-
TOTAL PROVED	3,947.6	3,324.0	-	-	-	-
PROBABLE	5,322.0	4,333.1	-	-	-	-
TOTAL PROVED PLUS PROBABLE	9,269.6	7,657.1	-	-	-	-

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:						
Developed Producing	186.0	172.5	-	-	1,221.8	1,119.3
Developed Non-Producing	198.0	160.3	-	-	229.2	185.8
Undeveloped	1,633.0	1,322.6	-	-	2,832.7	2,294.8
TOTAL PROVED	2,017.0	1,655.4	-	-	4,283.7	3,599.9
PROBABLE	3,209.8	2,600.1	-	-	5,857.0	4,766.5
TOTAL PROVED PLUS PROBABLE	5,226.8	4,255.6	-	-	10,140.7	8,366.3

TOTAL

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)
PROVED:						
Developed Producing	7,894.2	5,814.1	28,430.2	23,487.2	-	-
Developed Non-Producing	901.3	666.2	20,922.5	17,139.5	-	-
Undeveloped	6,234.1	4,898.2	37,584.1	30,712.2	-	-
TOTAL PROVED	15,029.5	11,378.5	86,936.9	71,338.9	-	-
PROBABLE	10,783.8	7,925.4	36,652.9	29,950.5	2,463.7	2,082.8
TOTAL PROVED PLUS PROBABLE	25,813.3	19,304.0	123,589.8	101,289.3	2,463.7	2,082.8

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:						
Developed Producing	87,726.0	70,058.5	2,756.0	2,100.2	53,701.5	43,077.9
Developed Non-Producing	16,804.9	11,516.1	594.2	432.8	25,218.7	20,157.8
Undeveloped	15,446.1	12,449.4	375.4	274.5	46,767.8	37,959.9
TOTAL PROVED	119,977.0	94,024.0	3,725.5	2,807.5	125,688.1	101,195.6
PROBABLE	58,225.8	43,379.0	1,846.3	1,381.2	61,450.8	48,569.8
TOTAL PROVED PLUS PROBABLE	178,202.8	137,403.1	5,571.8	4,188.7	187,138.9	149,765.2

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADA	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,570,813	1,328,371	1,153,750	1,025,230	927,159
Developed Non-Producing	934,865	671,482	504,487	392,656	314,426
Undeveloped	1,442,200	1,028,458	761,663	580,949	453,470
TOTAL PROVED	3,947,878	3,028,311	2,419,900	1,998,835	1,695,054
PROBABLE	2,143,969	1,385,887	965,439	711,673	548,133
TOTAL PROVED PLUS PROBABLE	6,091,847	4,414,198	3,385,339	2,710,508	2,243,188
UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	73,466	41,862	28,942	22,302	18,310
Developed Non-Producing	10,285	4,829	2,538	1,366	672
Undeveloped	128,892	49,242	17,650	2,469	(5,885)
TOTAL PROVED	212,643	95,933	49,130	26,137	13,096
PROBABLE	392,809	118,743	44,385	16,399	3,423
TOTAL PROVED PLUS PROBABLE	605,452	214,676	93,515	42,536	16,519
TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	1,644,279	1,370,233	1,1182,692	1,047,532	945,469
Developed Non-Producing	945,150	676,311	507,025	394,022	315,098
Undeveloped	1,571,092	1,077,700	779,313	583,418	447,585
TOTAL PROVED	4,160,521	3,124,244	2,469,030	2,024,972	1,708,150
PROBABLE	2,536,778	1,504,630	1,009,824	728,072	551,556
TOTAL PROVED PLUS PROBABLE	6,697,299	4,628,874	3,478,854	2,753,044	2,259,707

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

CANADA	AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,506,201	1,286,143	1,125,215	1,005,386	913,014
Developed Non-Producing	701,152	508,179	386,019	304,062	246,499
Undeveloped	1,108,930	791,187	586,072	446,926	348,587
TOTAL PROVED	3,316,283	2,585,509	2,097,305	1,756,374	1,508,100
PROBABLE	1,609,133	1,043,946	731,738	543,614	422,416
TOTAL PROVED PLUS PROBABLE	4,925,416	3,629,456	2,829,044	2,299.989	1,930,516

UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	42,936	24,612	17,064	13,173	10,830
Developed Non-Producing	5,983	2,719	1,314	574	123
Undeveloped	74,983	27,148	7,636	(2,063)	(7,595)
TOTAL PROVED	123,902	54,478	26,015	11,685	3,358
PROBABLE	228,881	67,090	22,422	5,270	(2,799)
TOTAL PROVED PLUS PROBABLE	352,784	121,568	48,436	16,955	559

TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	1,549,137	1,310,755	1,142,279	1,018,559	923,844
Developed Non-Producing	707,135	510,898	387,333	304,636	246,622
Undeveloped	1,183,913	818,335	593,708	444,863	340,992
TOTAL PROVED	3,440,185	2,639,987	2,123,320	1,768,059	1,511,458
PROBABLE	1,838,014	1,111,036	754,160	548,884	419,617
TOTAL PROVED PLUS PROBABLE	5,278,200	3,751,024	2,877,480	2,316,944	1,931,075

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2008
FORECAST PRICES AND COSTS

TOTAL PROVED RESERVES	REVENUE ($000s)	ROYALTIES ($000s)	OPERAT-ING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	WELL ABANDON-MENT COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Canada	7,759,971	1,466,630	1,852,826	384,973	107,664	3,947,878	631,595	3,316,284
United States	460,624	136,783	54,862	56,336	-	212,643	88,741	123,902
Total	8,220,595	1,603,413	1,907,688	441,309	107,664	4,160,521	720,336	3,440,186
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	11,876,380	2,312,969	2,810,466	510,282	150,815	6,091,848	1,166,431	4,925,417
United States	1,220,099	369,232	119,050	126,365	-	605,452	252,668	352,784
Total	13,096,479	2,682,201	2,929,516	636,647	150,815	6,697,300	1,419,099	5,278,201

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2008
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)	233,555	26.53
	Heavy Oil (including solution gas and other by-products)	1,749,549	24.31
	Bitumen	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	436,796	25.96
	Total Canada	2,419,900	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	334,871	26.13
	Heavy Oil (including solution gas and other by-products)	2,427,574	19.58
	Bitumen	14,034	6.74
	Natural Gas (including by-products but excluding natural gas from oil wells)	608,860	24.99
	Total Canada	3,385,339	
UNITED STATES			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	50,194	13.99
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	(1,064)	(81.83)
	Total United States	49,130	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	94,579	11.32
	Heavy Oil (including solution gas and other by-products)	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	(1,064)	(81.83)
	Total United States	93,515	
TOTAL			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	283,749	22.90
	Heavy Oil (including solution gas and other by-products)	1,749,549	24.31
	Bitumen	-	-
	Natural Gas (including by-products but excluding natural gas from oil wells)	435,732	25.88
	Total	2,469,030	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	429,450	20.29
	Heavy Oil (including solution gas and other by-products)	2,427,575	19.58
	Bitumen	14,034	6.74
	Natural Gas (including by-products but excluding natural gas from oil wells)	607,796	24.93
	Total	3,478,855	

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.

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, 2008, 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, 2008

	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						
2004	41.42	52.91	30.40	6.87	1.4	0.770
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 Est.	99.59	102.85	76.32	8.15	1.0	0.943
Forecast						
2009	53.73	65.35	47.05	6.82	2.0	0.800
2010	63.41	72.78	54.58	7.56	2.0	0.850
2011	69.53	79.95	59.96	7.84	2.0	0.850
2012	79.59	86.57	67.53	8.38	2.0	0.900
2013	92.01	94.97	74.08	9.20	2.0	0.950
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, 2008, excluding hedging activities, were $7.92/Mcf for natural gas, $88.92/bbl for light oil and NGL and $65.22/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, 2007	10,037.2	5,294.7	15,331.9	85,068.7	37,392.6	122,461.3
Extensions	-	-	-	409.5	333.9	743.4
Improved Recovery	467.3	247.3	714.6	3,305.7	7,380.6	10,686.3
Technical Revisions	2,016.9	(329.9)	1,687.0	6,269.3	(8,819.0)	(2,549.7)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	590.5	236.4	826.9	81.0	86.4	167.4
Dispositions	-	-	-	-	-	-
Economic Factors	36.6	13.3	49.9	486.8	263.3	750.1
Production	(2,066.6)	-	(2,066.6)	(8,721.7)	-	(8,721.7)
December 31, 2008	11,081.9	5,461.8	16,543.7	86,936.9	36,652.9	123,589.8

CANADA	BITUMEN Proved (Mbbl)	BITUMEN Probable (Mbbl)	BITUMEN Proved Plus Probable (Mbbl)	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)
December 31, 2007	-	-	-	103,969	44,888	148,857
Extensions	-	-	-	248	393	641
Improved Recovery	-	2,463.7	2,463.7	6,660	3,022	9,682
Technical Revisions	-	-	-	(6,053)	(7,620)	(13,673)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	31,945	13,782	45,727
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	1,233	551	1,784
Production	-	-	-	(20,042)	-	(20,042)
December 31, 2008	-	2,463.7	2,463.7	117,960	55,016	172,976

CANADA	NATURAL GAS LIQUIDS Proved (Mbbl)	NATURAL GAS LIQUIDS Probable (Mbbl)	NATURAL GAS LIQUIDS Proved Plus Probable (Mbbl)	OIL EQUIVALENT Proved (Mboe)	OIL EQUIVALENT Probable (Mboe)	OIL EQUIVALENT Proved Plus Probable (Mboe)
December 31, 2007	3,603.4	1,869.6	5,473.0	116,037.5	52,038.2	168,075.7
Extensions	32.3	6.1	38.4	483.2	405.5	888.7
Improved Recovery	166.0	66.7	232.7	5,049.1	10,661.9	15,711.0
Technical Revisions	(503.8)	(563.2)	(1,067.0)	6,773.6	(10,982.1)	(4,208.6)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	1,031.9	444.9	1,476.8	7,027.5	3,064.8	10,092.3
Dispositions	-	-	-	-	-	-
Economic Factors	35.3	22.2	57.5	764.3	390.6	1,154.9
Production	(639.6)	-	(639.6)	(14,768.3)	-	(14,768.3)
December 31, 2008	3,725.5	1,846.3	5,571.8	121,404.5	55,594.0	176,998.4

UNITED STATES	LIGHT AND MEDIUM OIL Proved (Mbbl)	LIGHT AND MEDIUM OIL Probable (Mbbl)	LIGHT AND MEDIUM OIL Proved Plus Probable (Mbbl)	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)
December 31, 2007	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Improved Recovery	-	3,367.9	3,367.9	96	2,099	2,195
Technical Revisions	-	-	-	-	-	-
Discoveries	-	-	-	-	-	-
Acquisitions	4,013.9	1,954.1	5,968.0	1,935	1,111	3,046
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(66.3)	-	(66.3)	(15)	-	(15)
December 31, 2008	3,947.6	5,322.0	9,269.6	2,016	3,210	5,226

UNITED STATES	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2007	-	-	-
Extensions	-	-	-
Improved Recovery	16.0	3,717.7	3,733.7
Technical Revisions	-	-	-
Discoveries	-	-	-
Acquisitions	4,336.4	2,139.3	6,475.6
Dispositions	-	-	-
Economic Factors	-	-	-
Production	(68.8)	-	(68.8)
December 31, 2008	4,283.6	5,857.0	10,140.5

TOTAL	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2007	10,037.2	5,294.7	15,331.9	85,068.7	37,392.6	122,461.3
Extensions	-	-	-	409.5	333.9	743.4
Improved Recovery	467.3	3,615.2	4,082.5	3,305.7	7,380.6	10,686.3
Technical Revisions	2,016.9	(329.9)	1,687.0	6,269.3	(8,819.0)	(2,549.7)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	4,604.4	2,190.5	6,794.9	81.0	86.4	167.4
Dispositions	-	-	-	-	-	-
Economic Factors	36.6	13.3	49.9	486.8	263.3	750.1
Production	(2,132.8)	-	(2,132.8)	(8,721.7)	-	(8,721.7)
December 31, 2008	15,029.5	10,783.8	25,813.3	86,936.9	36,652.9	123,589.8

TOTAL	BITUMEN			ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2007	-	-	-	103,969	44,888	148,857
Extensions	-	-	-	248	393	641
Improved Recovery	-	2,463.7	2,463.7	6,756	5,121	11,877
Technical Revisions	-	-	-	(6,053)	(7,620)	(13,673)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	33,880	14,893	48,773
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	1,233	551	1,784
Production	-	-	-	(20,057)	-	(20,057)
December 31, 2008	-	2,463.7	2,463.7	119,976	58,226	178,202

TOTAL	NATURAL GAS LIQUIDS Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2007	3,603.4	1,869.6	5,473.0	116,037.5	52,038.2	168,075.7
Extensions	32.3	6.1	38.4	483.2	405.5	888.7
Improved Recovery	166.0	66.7	232.7	5,065.1	14,379.6	19,444.7
Technical Revisions	(503.8)	(563.2)	(1,067.0)	6,773.6	(10,982.1)	(4,208.6)
Discoveries	-	-	-	37.6	15.1	52.7
Acquisitions	1,031.9	444.9	1,476.8	11,363.8	5,204.1	16,567.9
Dispositions	-	-	-	-	-	-
Economic Factors	35.3	22.2	57.5	764.3	390.6	1,154.9
Production	(639.6)	-	(639.6)	(14,837.0)	-	(14,837.0)
December 31, 2008	3,725.5	1,846.3	5,571.8	125,688.1	61,451.0	187,139.0

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 cash flow from operations is 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 over the next 8 years and probable undeveloped reserves over the next 10 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 four financial years and, in the aggregate, before that time.

Year	Light and Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Natural Gas Gross (MMcf)		NGLs Gross (Mbbl)	
	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	1,768.9	1,768.9	19,898.0	19,898.0	7,800	7,800	384.6	384.6
2005	197.7	1,660.2	9,077.7	28,722.2	11,318	19,027	424.0	615.1
2006	–	1,492.7	7,569.9	30,085.7	951	17,466	24.3	629.9
2007	2,112.0	3,574.1	9,833.3	38,168.8	2,559	15,587	55.6	378.4
2008	2,830.6	6,234.1	2,175.9	37,584.1	3,234	15,446	37.3	375.4

Sproule assigned a total of 451 well locations to the proved undeveloped reserve category. 358 of these wells are located on our Canadian heavy oil producing properties. There were no proved undeveloped bitumen reserves assigned by Sproule. The 358 heavy oil proved undeveloped locations are scheduled to be drilled over the next six years. 66 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 six years. The remaining 27 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 cash flow from operations to exploration and development activities. This restricts the number of development wells we drill in any given year to approximately 120 based on 2008 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 five to 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 four financial years and, in the aggregate, before that time.

Year	Light and Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Natural Gas Gross (MMcf)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	673.3	673.3	11,351.5	11,351.5	5,304	5,304
2005	19.6	523.7	3,209.0	13,621.9	8,555	12,774
2006	2.0	524.6	4,556.5	17,591.8	291	8,451
2007	1,040.8	1,557.5	3,804.1	20,410.1	5,476	10,832
2008	5,179.3	6,404.7	4,833.2	20,634.7	5,467	13,587

Year	NGLs Gross (Mbbl)		Bitumen Gross (Mbbl)	
	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
Prior	61.8	61.8	–	–
2005	608.0	608.0	–	–
2006	1.4	302.6	–	–
2007	513.3	615.7	–	–
2008	76.3	362.2	2,463.7	2,463.7

Sproule assigned a total of 249 well locations to the probable undeveloped reserve category, of which 178 are located within our Canadian primary heavy oil producing properties. These 178 heavy oil locations are scheduled to be drilled over the next ten years. Ten of these probable undeveloped locations are thermal heavy oil wells (bitumen) located in the Seal area of Alberta. Sproule has scheduled these thermal wells to be drilled by the end of 2013. Twenty-three 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 ten years. The remaining 38 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 five 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 cash flow from operations to exploration and development activities. This restricts the number of development wells we drill in any given year to approximately 120 based on 2008 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 10 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.

YEAR	FORECAST PRICES AND COSTS Proved Reserves ($000s)	Proved Plus Probable Reserves ($000s)
	CANADA	
2009	100,278	101,448
2010	97,693	102,769
2011	62,646	64,417
2012	57,001	60,238
2013	18,900	53,147
Remaining	48,455	128,264
Total (Undiscounted)	384,973	510,282
	UNITED STATES	
2009	26,355	26,355
2010	23,824	39,706
2011	-	39,706
2012	6,157	18,929
2013	-	1,668
Remaining	-	-
Total (Undiscounted)	56,336	126,365
	TOTAL	
2009	126,633	127,803
2010	121,517	142,475
2011	62,646	104,123
2012	63,158	79,167
2013	18,900	54,815
Remaining	48,455	128,263
Total (Undiscounted)	441,309	636,647

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 cash flow 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

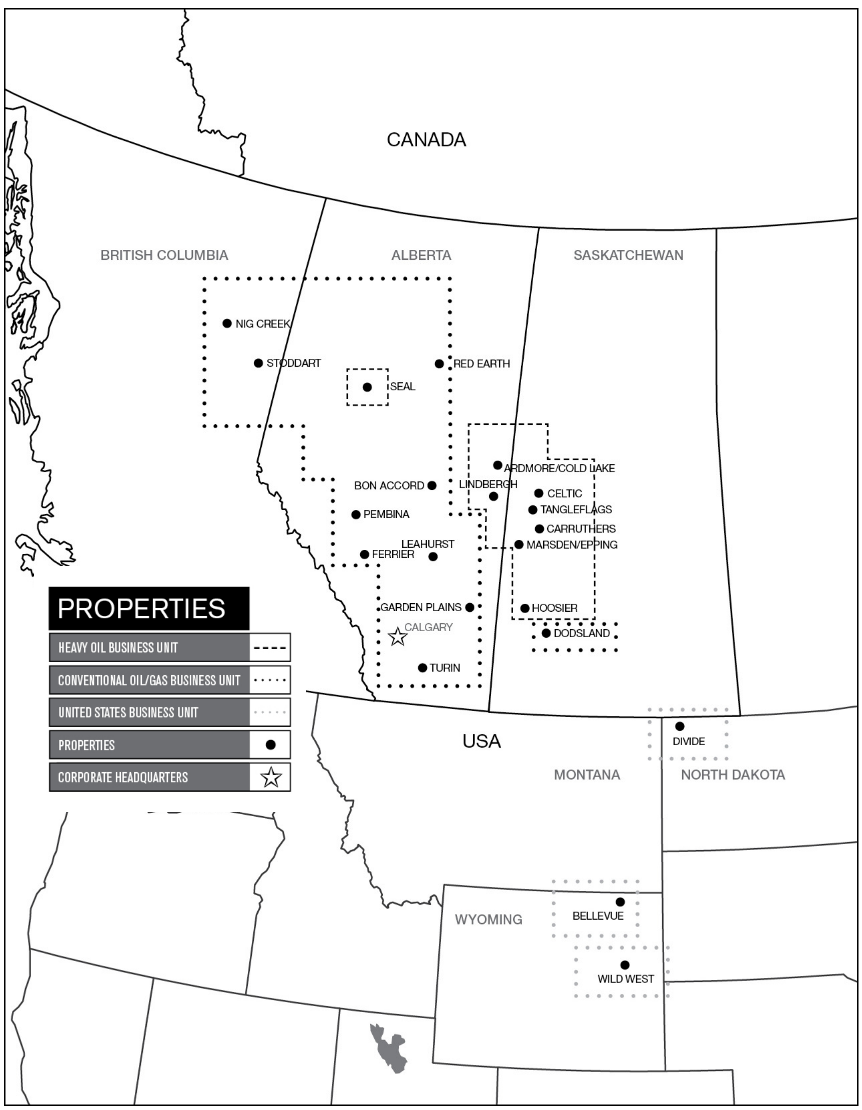
The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2008. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2008. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2008, except where otherwise indicated.

Our crude oil and natural gas operations are organized into Canadian Heavy Oil, Canadian Conventional Oil and Gas and U.S. business units. Each business unit has an extensive portfolio of operated properties and development prospects with considerable 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 $70 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 resources 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



Heavy Oil Business Unit

The Heavy Oil business unit accounts for more than 55% of current production and more than 65% 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 250 bbl/d of crude with gravities ranging from 11 to 18 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 2008, production in the Heavy Oil business unit averaged approximately 23,530 bbl/d of heavy oil and 6,654 Mcf/d of natural gas (24,639 Boe/d). Baytex drilled 111 (103.8 net) wells in the Heavy Oil business unit resulting in 105 (97.8 net) oil wells, 4 (4.0 net) stratigraphic test wells, and 2 (2.0 net) dry and abandoned wells, for a success rate of 98%.

The 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. Because of our large 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 Heavy Oil business unit totalled approximately 348,000 acres at year-end 2008.

Listed below is a brief description of the principal properties within the 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 2008 was approximately 1,395 bbl/d of oil and 455 Mcf/d of natural gas (1,471 boe/d). Seven successful oil wells and no dry holes were drilled in the area during 2008. Baytex anticipates drilling four wells in this area in 2009. Due to extensive Baytex infrastructure in this area, operating expenses in 2008 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2008.

<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. No new wells were drilled in 2008, but 4 re-completions were conducted. Despite the absence of new well drilling, year-over-year production decline was only about 8% due mostly to strong performance of the ongoing waterflood. Average production in 2008 was approximately 2,115 bbl/d of heavy oil and 650 Mcf/d of natural gas (2,224 boe/d). Net undeveloped lands were 9,900 acres at year-end 2008.

<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 4,670 bbl/d of heavy oil and 1,118 Mcf/d of natural gas (4,856 boe/d) during 2008. (This production number includes very minor production in the area held prior to the Celtic acquisition). 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

2009, Baytex expects to drill 10 new wells and re-complete approximately 45 existing wells. Net undeveloped lands were 8,800 acres at year-end 2008.

Cold Lake, Alberta: 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 2008 was approximately 507 bbl/d. Baytex drilled two successful oil wells in the Cold Lake area in 2008, and we plan to drill three new wells in the area in 2009. Net undeveloped lands were 13,600 acres at year-end 2008.

Dodsland, Saskatchewan: During 2008, Baytex developed a new resource play in the Viking sand in southwest Saskatchewan. The zone is regionally charged with light (34 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. At year-end 2008, Baytex had leased 34,600 net acres in the play. Ultimately, up to 150 wells may be drilled on these lands.

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 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 2008 was approximately 3,380 bbl/d of oil and 831 Mcf/d of natural gas (3,518 boe/d). Twenty-three successful oil wells were drilled in this region in 2008. In addition, a significant facility expansion involving water flow-lining and conservation of the solution gas was completed. This project has reduced operating costs in the area and tied-in approximately 300 Mcf/d of solution gas into the local sales network. For 2009, a further 14 wells are planned. Net undeveloped lands were 26,300 acres at year-end 2008.

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 rates of 150 to 250 bbl/d per well, without employing more cost-intensive methods such as steam injection. In 2008, Baytex drilled four stratigraphic test wells, designed to identify extensions to our current development areas. Baytex also drilled 19 horizontal production wells in 2008, bringing the total number of producing wells to 44. The average production rate during 2008 was 3,707 bbl/d of heavy oil. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly 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. Due to the positive results from our steam pilot, the year-end 2008 reserve report included an assignment for thermal reserves at Seal for the first time. This reserve assignment supports our assessment that commercial cyclic steam development at Seal is economically viable. Seal area facilities were expanded in 2008 by constructing a water disposal plant and a fuel gas supply pipeline. Operating costs for primary production are forecasted to remain very low at $4 to $5/bbl and the gas pipeline ensures an adequate fuel supply for future thermal development of the property. As the region continues to develop, the Seal property will take an increasingly more prominent role in our production profile. During 2009, Baytex plans to drill two additional stratigraphic test wells and 14 additional cold horizontal production wells. Net undeveloped lands were 65,000 acres at year-end 2008.

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. Accordingly, this property supplies long-term development potential through a considerable number of re-completion opportunities. In 2008, Baytex drilled 3 wells and a further 15 wells were either re-started or re-completed to a new zone. Average production during 2008 was approximately 1,626 bbl/d of heavy oil and 915 Mcf/d of natural gas (1,779 boe/d). In 2009, Baytex plans to re-work or re-complete about 15 existing wells. Net undeveloped lands were 7,100 acres at year-end 2008.

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in June of 2007. Oil production at Lindbergh is operated by a senior Canadian producer. Baytex has a 21.25% working interest. Company-interest production is approximately 800 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. Nine (1.9 net) wells were drilled in this area in 2008. Baytex expects the field operator to maintain a level of activity that would result in an approximately flat production rate. Net undeveloped lands were 11,000 acres at year-end 2008.

Conventional 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 Conventional 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 2008, production from this business unit averaged 48,066 Mcf/d of natural gas sales and 7,401 bbl/d of light oil and NGL (15,412 boe/d). During 2008, the Conventional Oil and Gas Business Unit drilled 31 (21.4 net) wells resulting in 18 (11.9 net) gas wells, 7 (4.1 net) oil wells, 2 (1.4 net) service wells, and 4 (4.0 net) dry holes for a success rate of 87.1% (81.3% net). Our net undeveloped lands in this business unit were approximately 329,000 acres at year-end 2008.

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

<u>Bon Accord, Alberta</u>: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2008, production for the area averaged approximately 2,524 Mcf/d of gas and 264 bbl/d of light oil (685 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2008, Baytex drilled two (1.75 net) oil wells in this area. At year-end 2008, Baytex had 11,500 net undeveloped acres in this area.

<u>Darwin/Nina, Alberta:</u> 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 2008 averaged approximately 2,209 Mcf/d of gas (368 boe/d). At year-end 2008, Baytex had 18,100 net undeveloped acres in this area.

<u>Leahurst, Alberta</u>: Production averaged approximately 4,109 Mcf/d of gas and 11 bbl/d of NGL (696 boe/d) during 2008 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 2008, Baytex participated in the drilling of 4 operated and 1 non-operated locations, resulting in 4 (2.9 net) producing gas wells and 1 (1.0 net) dry hole. At year-end 2008, Baytex had 11,700 net undeveloped acres in this area.

<u>Pembina, Alberta:</u> 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 2008, Pembina production averaged 4,062 bbl/d of light oil and NGL and 13,272 Mcf/d of gas (6,274 boe/d). Baytex participated in drilling 6 (5.0 net) operated and 2 (0.6 net) non-operated locations in 2008. Four wells (2.3 net) were drilled to test Nisku prospects, resulting in 1 (0.6 net) oil well, 1 (0.4 net) gas well and 2 (1.4 net) service wells. Four (3.3 net) wells were drilled for development of multi-zone potential in the Cretaceous in 2008, resulting in 3 (3.0 net) gas wells and 1 (0.25 net) dry hole. The 2009 drilling program for Pembina will include up to three wells to evaluate Nisku prospects and four wells for multi-zone Cretaceous potential. During the first quarter of 2009, Baytex will be constructing a pipeline in the Pembina O'Chiese area to increase gas volumes delivered to market and improve netback prices for our Pembina production. At year-end 2008, Baytex had 32,600 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 2008, production averaged approximately 5,971 Mcf/d of sales gas and 11 bbl/d of NGL (1,006 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 2008, Baytex drilled 5 (1.7 net) wells in this area, resulting in 3 (1.5 net) gas wells and 2 (0.2 net) oil wells. At year-end 2008, Baytex had 29,200 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 2008 averaged approximately 4,058 Mcf/d of gas and 770 bbl/d of light oil and NGL (1,446 boe/d). During 2008, Baytex drilled 4 (3.1 net) wells in this area, resulting in 1 (0.5 net) oil well, 1 (0.6 net) gas well, and 2 (2.0 net) dry holes. At year-end 2008, Baytex had 28,600 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 2008 averaged approximately 8,375 Mcf/d of gas and 1,392 bbl/d of oil and NGL (2,788 boe/d). Baytex drilled 3 (2.4 net) wells in 2008 resulting in 1 (1.0 net) oil well, 1 (0.4 net) gas well, and 1 (1.0 net) dry hole. During 2009, Baytex plans to drill two wells in the area. At year-end 2008, Baytex had 32,000 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2008 averaged approximately 519 bbl/d of oil and NGL and 1,383 Mcf/d of gas (750 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. During 2008, Baytex drilled one (0.1 net) gas well in this area. At year-end 2008, Baytex had 9,600 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 2008, Baytex USA drilled and/or acquired an interest in 34 (12 net) wells and increased its acreage position to over 120,000 net acres. Net production from the United States properties averaged 188 boe/d in 2008 and 339 boe/d in December 2008.

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. In 2008, Baytex USA participated in 8 gross (3 net) wells. Baytex USA also participated in the acquisition of a new 3D seismic survey covering 188,000 acres. This survey was 73% complete at the end of 2008. Net production from the project was approximately 341 boe/d in the fourth quarter of 2008. In 2009, Baytex USA plans to drill 6 gross (2.25 net) horizontal wells. Ultimately, the project has the potential to include 150 to 300 wells with average initial rates expected to be 190 boe/d or more per well and average recoveries expected to be 280 mboe/well or more.

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, is scheduled for the first quarter of 2009. Baytex USA views horizontal, multi-zone hydraulically-fractured wells as the most promising method to ultimately develop the Mowry, although there have been no horizontal wells drilled in the project area to-date. A horizontal well is planned to further evaluate the prospect in 2009. Ultimately, the project may include up to 60 horizontal wells.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2008.

	Light Oil and NGL (bbl/d)	**Heavy Oil (bbl/d)**	**Gas (Mcf/d)**	**Oil Equivalent (boe/d)**
Heavy Oil Business Unit				
Ardmore	-	1,395	455	1,471
Carruthers	-	2,115	651	2,224
Celtic	-	4,670	1,118	4,856
Cold Lake	-	507	-	507
Golden lake	-	726	-	726
Greenstreet	-	-	1,238	206
Hoosier	-	452		452
Lashburn	-	65	34	71
Lindbergh	-	797	59	807
Maidstone	-	883	-	883
Marsden	-	729	-	729
Neilburg	-	548	-	548
Poundmaker	-	1,560	317	1,613
Seal	-	3,707	-	3,707
Silverdale / Epping / Macklin / Buzzard	-	2,651	445	2,725
Sugden	-	546	-	546
Tangleflags	-	1,626	915	1,779
Remaining properties	-	553	1,422	789
Total Heavy Oil Business Unit	-	23,530	6,654	24,639
Conventional Oil and Gas Business Unit				
Bon Accord	264	-	2,524	685
Darwin/Nina	-	-	2,209	368
Goodfish	-	-	3,590	598
Hamburg/Chinchaga	33	-	1,957	359
Leahurst	11	-	4,109	696
Pembina	4,062	-	13,272	6,274
Red Earth	770	-	56	779
Richdale / Sedalia	11	-	5,971	1,006
Stoddart	1,392	-	8,375	2,788
Tangent	-	-	281	47
Turin	519	-	1,383	750
Viking	-	-	1,079	180
Remaining Properties	339	-	3,260	882
Total Conventional Oil and Gas Business Unit	7,401	-	48,066	15,412
United States Business Unit	181	-	41	188
Grand Total	7,582	23,530	54,761	40,239

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2008:

($000s)	Canada	United States	Total
Property acquisition costs [1]			
Proved properties	131,584	5,636	137,220
Unproved properties	63,587	64,292	127,879
Total Property acquisition costs	195,171	69,928	265,099
Development Costs [2]	140,887	36,892	177,779
Exploration Costs [3]	6,026	1,278	7,304
Total	342,084	108,098	450,182

Notes:
(1) Property acquisition costs include the corporate acquisition of Burmis and are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of geological and geophysical capital expenditures and drilling costs for 2008 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, 2008.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	774	452.8	827	415.5	601	432.7	357	271.2
British Columbia	56	55.2	28	26.8	34	29.6	16	13.2
Saskatchewan	1,083	1,006.9	797	755.4	46	42.3	54	51.3
North Dakota	27	8.4	2	0.7	-	-	-	-
Wyoming	2	1.3	3	2.1	-	-	-	-
Total	1,942	1,524.6	1,657	1,200.5	681	504.6	427	335.7

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2008.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	594,047	446,722
British Columbia	85,583	61,928
Saskatchewan	184,870	168,428
Total Canada	864,500	677,078
United States		
North Dakota	251,590	94,346
Utah	920	460
Wyoming	47,435	25,248
Total United States	299,945	120,054
Grand Total	1,164,445	797,132

We expect that rights to explore, develop and exploit approximately 119,383 net acres of our undeveloped land holdings may expire on or before December 31, 2009. There are no material drilling commitments associated with the land holdings expiring by December 31, 2009.

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, 2008.

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil	1	0.3	121	106.4
Natural Gas	3	2.9	14	9.4
Evaluation	6	4.4	-	-
Service	-	-	-	-
Dry	3	2.9	4	4.0
Total	13	10.5	139	119.8

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2008, see Notes 16 and 17 to our annual audited financial statements as at and for the year ended December 31, 2008, 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 by Baytex of the NPI on underlying oil and gas properties and the deduction of 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, 2008	267.74	32.21
Anticipated to be paid in 2008	1.22	1.17
Anticipated to be paid in 2009	1.11	0.99
Anticipated to be paid in 2010	0.71	0.59

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 4,092 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 660 wells which are all the proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2008. Abandonment and reclamation costs have been estimated over a 50 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 $267.7 million ($32.2 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, 2008.

	($000s)
Exploration and Development	
Land	9,534
Seismic	4,947
Drilling and completion	132,296
Equipment	34,720
Other	3,586
Total exploration and development	185,083
Acquisitions (net of dispositions)	
Corporate acquisitions	180,467
Property acquisitions	84,826
Property dispositions	(194)
Total Acquisitions (net of dispositions)	265,099
Net capital expenditures	450,182

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2009, 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 (Mcf/d)	Natural Gas Liquids (bbl/d)	Oil Equivalent (boe/d)
CANADA					
Total Proved	5,511.3	28,057.1	56,659.6	1,902.1	44,913.7
Total Proved plus Probable	6,066.6	29,577.2	62,021.4	2,087.3	48,068.0
UNITED STATES					
Total Proved	560.4	-	483.0	-	640.9
Total Proved plus Probable	562.4	-	483.0	-	642.9
TOTAL					
Total Proved	6,071.7	28,057.1	57,142.6	1,902.1	45,554.6
Total Proved plus Probable	6,629.0	29,577.2	62,504.4	2,087.3	48,710.9

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.

	Quarter Ended 2008				Year Ended
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31, 2008**
Average Daily Production (1)					
Light Oil and NGL (bbl/d) (2)	7,803	8,377	6,778	7,330	7,575
Heavy Oil (bbl/d)	24,635	24,078	22,905	22,484	23,530
Natural Gas (MMcf/d)	57,583	60,500	50,974	50,058	54,802
Total (boe/d)	42,035	42,538	38,179	38,157	40,239
Average Net Production Prices Received					
Light Oil and NGL($/bbl) (2)	55.31	107.41	109.26	84.91	88.92
Heavy Oil ($/bbl)	38.93	84.65	78.92	59.65	65.22
Natural Gas ($/Mcf)	7.05	8.01	9.29	7.42	7.92
Total ($/boe)	42.71	80.44	79.15	61.16	65.66
Royalties Paid					
Light Oil and NGL($/bbl) (2)	15.66	26.25	28.05	22.48	22.97
Heavy Oil ($/bbl)	6.09	19.50	15.38	11.14	12.93
Natural Gas ($/Mcf)	1.18	1.63	1.84	1.37	1.50
Total ($/boe)	8.08	18.52	16.65	12.64	13.92
Production Costs (3)(4)					
Light Oil and NGL($/bbl) (2)	13.64	11.41	13.86	10.81	12.38
Heavy Oil ($/bbl)	11.59	12.63	11.24	10.69	11.55
Natural Gas ($/Mcf)	2.04	1.76	1.90	1.68	1.85
Total ($/boe)	12.12	11.92	11.76	10.60	11.60
Transportation					
Light Oil and NGL($/bbl) (2)	0.13	0.61	0.61	0.56	0.47
Heavy Oil ($/bbl)	5.24	4.16	3.98	2.94	4.22
Natural Gas ($/Mcf)	0.13	0.13	0.12	0.14	0.13
Total ($/boe)	3.28	2.65	2.67	2.05	2.74
Netback Received (5)					
Light Oil and NGL($/bbl) (2)	25.88	69.14	66.74	51.06	53.10
Heavy Oil ($/bbl)	16.01	48.36	48.32	34.88	36.52
Natural Gas ($/Mcf)	3.70	4.49	5.43	4.23	4.44
Total ($/boe)	19.23	47.35	48.07	35.87	37.40

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.

Marketing Arrangements

Natural Gas

We continue to maintain a risk-mitigating strategy and cultivate a diverse natural gas sales portfolio, which encompasses a variety of pricing mechanisms and term commitments. Our marketing objectives also include protecting or securing minimum prices for up to 50% of net production for terms not exceeding two years. Our hedging methodology generally includes employing collars, floors or fixed price contracts. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our natural gas transactions. Our natural gas portfolio includes sales to industrial consumers, distribution companies and traditional aggregators.

For 2009, Baytex has entered into two costless collar contracts which will provide downside protection on the natural gas price while still allowing Baytex to participate in upside price potential. For calendar 2009, a costless collar has been put in place on 4.7 MMcf/d of natural gas, with a floor price of $7.39/Mcf and a ceiling price of $8.39/Mcf. For April to December 2009, a costless collar has been put in place on 4.7 MMcf/d of natural gas, with a floor price of $5.28/Mcf and a ceiling price of $6.65/Mcf.

Oil and NGL

Benchmark WTI prices began 2008 around US$92 per barrel, climbed to an all-time high of US$145 per barrel in July, and ended the year at about US$40 per barrel. The average WTI price for 2008 was US$99.64 per barrel, an increase of 38 percent from the 2007 average of US$72.31 per barrel.

Baytex's light oil and natural gas liquids prices averaged $88.92 per barrel in 2008, an increase of 36 percent from the 2007 average of $65.53 per barrel. Our heavy oil prices averaged $72.20 per barrel in 2008, an increase of 63% from the 2007 average of $44.28 per barrel.

For 2009, Baytex has entered into two costless collar contracts which will provide significant downside protection on the oil price while still allowing Baytex to participate in upside price potential. WTI costless collars have been put in place for 2009 on 4,000 bbl/d, at a weighted average price from US$100.00 to US$154.55 per barrel. In addition, Baytex has entered into a series of physical heavy sour crude oil sales agreements requiring delivery of blended volumes for sales at a fixed pricing differential to WTI. For 2009, we have two contracts in place to sell 10,340 bbl/d at approximately 67% of WTI. To further mitigate our price exposure, we recently entered into two more physical heavy sour crude oil sales agreements, each for 775 bbl/d for the period from April 2009 to August 2009. The first agreement is priced at WTI minus a fixed US$10.00 per barrel and the second one is priced at 80% of WTI.

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.

Convertible Debentures

On June 6, 2005, we issued $100 million principal amount of Convertible Debentures for net proceeds of $95.8 million. 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 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).

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 the 15th day of each month (or the first business day thereafter) to holders of Trust Units of record on the immediately preceding record date.

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 available cash flow from operations for capital expenditures. Depending upon commodity prices, between 50 to 60 percent of our available cash flow 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 Baytex's facilities or upon a material borrowing base shortfall or default.

Baytex's senior subordinated notes also contain certain limitations on maximum cumulative distributions. Restricted payments include the declaration or payment of any dividend or distribution to us and the payment of interest or principal on subordinated debt owed to us. Baytex is restricted from making any restricted payments, including distributions to us, if a default or event of default under the note indenture governing the subordinated debt has occurred and is continuing. If no such default or event of default has occurred and is continuing, Baytex may make a distribution to us provided at the time either (A) (i) its ratio of consolidated debt to consolidated cash flow from operations does not exceed 3 to 1, (ii) its fixed charge coverage ratio for the preceding four fiscal quarters is greater than 2.5 to 1 and (iii) the aggregate of all restricted payments declared or made after July 9, 2003 does not exceed the sum of 80 percent of the consolidated cash flow from operations accrued on a cumulative basis since July 9, 2003 plus the net cash proceeds received by Baytex from the issuance of deeply subordinated intercompany debt or the receipt of capital contributions from the Trust plus net proceeds received by Baytex from the issuance of and upon conversion of debt and other securities or (B) the aggregate amount of all restricted payments declared or made after July 9, 2003 does not exceed the sum of permitted restricted payments not previously made plus US$30,000,000.

Cash distributions on the Trust Units are paid at the discretion of the Board of Directors and can fluctuate depending on the level of cash flow 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]	2009	2008	2007	2006	2005	2004	2003
January	$0.18	$0.18	$0.18	$0.18	$0.15	$0.15	-
February	0.12	0.18	0.18	0.18	0.15	0.15	-
March		0.20	0.18	0.18	0.15	0.15	-
April		0.20	0.18	0.18	0.15	0.15	-
May		0.20	0.18	0.18	0.15	0.15	-
June		0.25	0.18	0.18	0.15	0.15	-
July		0.25	0.18	0.18	0.15	0.15	-
August		0.25	0.18	0.18	0.15	0.15	-
September		0.25	0.18	0.18	0.15	0.15	$0.15
October		0.25	0.18	0.18	0.15	0.15	0.15
November		0.25	0.18	0.18	0.15	0.15	0.15
December		0.18	0.18	0.18	0.15	0.15	0.15
Total		$2.64	$2.16	$2.16	$1.80	$1.80	$0.60

Note:
(1) Cash distributions are made on the 15th day (or if such date is not a business day, on the next business 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 be 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 in 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, 2008, 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, 2008, 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	51	Director	Partner with Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	53	Director and Executive Chairman	Executive Chairman of Baytex
Edward Chwyl (2) (3) (4) Victoria, B.C.	65	Director	Independent Businessman
Naveen Dargan (1) (2) (4) Calgary, Alberta	51	Director	Independent Businessman
R.E.T. (Rusty) Goepel (1) Vancouver, B.C.	66	Director	Senior Vice President of Raymond James Ltd.
Anthony W. Marino Calgary, Alberta	48	Director, President and Chief Executive Officer	President and Chief Executive Officer of Baytex
Gregory K. Melchin(1) Calgary, Alberta	55	Director	Independent Businessman
Dale O. Shwed (3) (7) Calgary, Alberta	50	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	46	Chief Financial Officer	Chief Financial Officer of Baytex
Randal J. Best Calgary, Alberta	52	Senior Vice President, Corporate Development	Senior Vice President, Corporate Development of Baytex
Stephen Brownridge Calgary, Alberta	49	Vice President, Heavy Oil	Vice President, Heavy Oil of Baytex
Brett J. McDonald Calgary, Alberta	46	Vice President, Land	Vice President, Land of Baytex
Timothy R. Morris Denver, Colorado	52	Vice President, US Business Development	Vice President, US Business Development of Baytex
R. Shaun Paterson Calgary, Alberta	55	Vice President, Marketing	Vice President, Marketing of Baytex
Marty L. Proctor Calgary, Alberta	48	Chief Operating Officer	Chief Operating Officer of Baytex
Mark F. Smith Calgary, Alberta	51	Vice President, Conventional Oil & Gas	Vice President, Conventional Oil & Gas of Baytex
Shannon M. Gangl Calgary, Alberta	46	Corporate Secretary	Partner with Burnet, Duckworth & Palmer LLP

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.

(7) Mr. Shwed was a director of Echelon Energy Inc., a private company incorporated under the *Business Corporations Act* (Alberta). In September 1999, a receiver-manager was appointed over the assets of Echelon.

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., Energy Savings Income Fund, Highpine Oil & Gas Limited, Harvest Energy Trust, 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 and 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, Heavy Oil on December 1, 2006. 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. 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.

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. Prior to joining Baytex, Mr. Morris was Vice President, Land and Administration of Berco Resources, LLC since 2000. Mr. Morris has over 31 years of experience in the United States oil and gas industry. Prior to working with Berco, he held senior management positions with 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 active 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. He began his career in the oil and gas business working as a roughneck on drilling rigs in Alberta, British Columbia, and northern Canada. 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.

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.

Shannon M. Gangl has been the Corporate Secretary of Baytex since July 25, 2003. She is a partner at Burnet, Duckworth & Palmer LLP and focuses in the areas of mergers and acquisitions, oil and gas transactions and other commercial matters. She was admitted to the Alberta bar in 1993. She is a member of various professional associations such as the Law Society of Alberta, the Canadian Bar Association and the Calgary Bar Association. She obtained a Bachelor of Laws degree from the University of Victoria and a Bachelor of Commerce degree from the University of Alberta.

Ownership of Securities by Management

As at February 28, 2009, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,080,318 Trust Units, or approximately 1.1 percent of the issued and outstanding Trust Units. No Convertible 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, 2008, Baytex employed 141 head office employees and 45 field office employees.

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. Senior Vice President of Raymond James Ltd.
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 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 2008 and 2007:

	Aggregate fees billed ($000s)	
	2008	**2007**
Audit Fees	$1,124	$851
Audit-Related Fees	-	-
Tax Fees	56	5
All Other Fees	84	133
	$1,264	$989

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 2008 and 2007 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 an acquisition and 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 fiscal 2008 and 2007, 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, 2008, 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. As a result, as at December 31, 2008, there were no Exchangeable Shares outstanding.

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
<u>2008</u>						
January	20.08	16.30	8,450,915	20.30	15.88	1,550,400
February	21.51	17.54	7,664,775	22.00	17.37	1,507,100
March	23.40	20.22	9,631,945	23.34	20.33	1,693,100
April	26.50	22.60	10,428,318	26.35	21.90	1,459,700
May	30.63	24.38	11,361,346	31.08	23.90	1,806,900
June	35.37	28.31	12,992,517	34.98	28.09	1,723,200
July	35.01	27.77	11,828,510	35.20	27.57	4,026,107
August	32.50	28.26	7,657,965	31.33	26.55	2,184,663
September	31.40	23.15	12,133,861	29.22	22.35	4,028,994
October	27.05	15.01	13,840,975	25.49	12.65	6,992,149
November	22.00	15.05	7,500,940	19.14	11.72	3,493,110
December	18.45	12.81	9,925,351	14.44	10.16	4,012,617
<u>2009</u>						
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

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 ($)	Price Range Low ($)	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			
January	135.00	121.50	336.0
February	144.22	123.00	210.0
March	158.26	142.19	854.0
April	175.00	152.39	754.0
May	200.00	165.99	917.0
June	235.24	190.02	1,158.0
July	230.71	193.89	374.0
August	210.00	200.00	199.0
September	210.00	167.41	101.0
October	155.27	112.75	388.0
November	129.00	105.03	12.0
December	112.34	94.60	40.0
2009			
January	104.32	100.00	12.0
February	100.00	93.03	155.0

RATINGS

In June 2008, Dominion Bond Rating Service Limited ("**DBRS**") assigned to us a stability rating of STA-5 (low), an upgrade from the previous rating of STA-6 (high). 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 its senior subordinated notes 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-/Stable and its senior subordinated notes have been assigned a credit rating of B+/Stable 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, and

Shannon Gangl, the Corporate Secretary of Baytex, who are partners 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) our trust unit rights incentive plan (filed on SEDAR on March 26, 2009); and

(f) the credit agreement in respect of our $485 million syndicated credit facility (filed on SEDAR on March 28, 2008 and September 15, 2008).

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

INDUSTRY CONDITIONS

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 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 controls or regulations will affect our operations in a manner materially different than they would affect other oil and 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 and Natural Gas

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 the markets, the value of refined products, the supply/demand balance, and other contractual terms. 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 licence requires a public hearing and the approval of the Governor in Council.

The price of natural gas is determined by 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 a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such 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

Although pipeline expansions are ongoing, the proximity, availability and lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, United States of America, 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 countries are prohibited from imposing minimum or maximum export or import price requirements, provided, in the case of export price requirements, any prohibition in any circumstances in which any other form of quantitative restriction is prohibited, and in the case of import-price requirements, 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 and to minimize disruption of contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection, and other matters. The royalty regime 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. Our operations which are not Crown lands and are subject to the provisions of specific agreements are also usually subject to royalties negotiated between the mineral owner and the lessee. These royalties are not eligible for incentive programs sponsored by various governments as discussed below. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the 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, and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and funds from operations within the industry. Royalty holidays and reductions would reduce the amount of Crown royalties paid by oil and gas producers to the provincial governments and would increase the net income and funds from operations of such producers. However, the trend in recent years has been for provincial governments to eliminate, amend or allow such incentive programs to expire without renewal, and consequently we cannot predict whether existing incentive programs will be continued or new incentive programs enacted.

The Canadian federal corporate income tax rate levied on taxable income is 19.5% effective January 1, 2008 and 19% effective January 1, 2009 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008, the federal corporate income tax rate will decrease to 15% in three additional steps: 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 1, 2012.

Alberta

In Alberta, companies are granted the right to explore, produce and develop petroleum and natural gas resources in exchange for royalties, bonus bid payments and rents. On October 25, 2007, the Government of Alberta released a report entitled "The New Royalty Framework" (the "**NRF**") containing the Government's proposals for Alberta's new royalty regime, which was followed by the *Mines and Minerals (New Royalty Framework) Amendment Act*, 2008, which was given Royal Assent on December 2, 2008. The NRF and the applicable new legislation became effective on January 1, 2009. Prior to the NRF, the amount of royalties that were payable was influenced by the oil production rate, the density of the oil, the vintage of the oil and the selling price of the oil. Originally, the vintage classified oil was "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it was considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it was considered "new oil". In 1992, the Alberta Government introduced a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 1, 1992. The new oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown had a base rate of 10% and a rate cap of 35%. The NRF eliminates these classifications and establishes new royalty rates for conventional oil, natural gas and oil sands. The new royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and increases the royalty from 30% to 35% applied to the old and new tiers, to up to 50% and with rate caps once the price of conventional oil reaches $120 per barrel. The sliding rate formula includes in its calculation the price of oil and well production.

With respect to natural gas, and similar to the conventional oil framework, the royalties outlined in the NRF are set by a single sliding rate formula ranging from 5% to 50% with a rate cap once the price of natural gas reaches $16.59/GJ. Prior to the NRF, the royalty reserved to the Crown in respect of natural gas production, subject to various incentives, was between 15% and 30%, in the case of new natural gas, and between 15% and 35%, in the case of old natural gas, depending upon a prescribed or corporate average reference price.

In response to the drop in commodity prices experienced during the second half of 2008, the Government of Alberta announced on November 19, 2008, the introduction of a five year program of transitional royalty rates with the intent of promoting new drilling. Under this new program companies drilling new natural gas or conventional oil deep wells (between 1,000 and 3,500 metres) will be 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. In order to qualify for this program wells must be drilled during the period starting on November 19, 2008 and ending on December 31, 2013. Following this period all new wells drilled will automatically be subject to the NRF.

Oil sands projects are now subject to the NRF, and regulated, among others, by the *Oil Sands Royalty Regulation, 2009 Oil Sands Allowed Costs (Ministerial) Regulation* and the *Bitumen Valuation Methodology (Ministerial) Regulation, 2009*, all approved by the Government of Alberta on December 10, 2008. The rates applicable to oil sands are between 1% and 9% before payout and are calculated depending on the price of WTI expressed in Canadian dollars. The royalty payable is 1% when oil is priced below or at $55 per barrel and it increases for every dollar over and above that price, to a maximum of 9% when oil is priced at $120 or higher. The after payout net profit interest starts at 25% and increases for every dollar when oil is priced above $55 up to 40% when oil is priced at $120 or higher.

On April 10, 2008, the Government of Alberta introduced two new royalty programs that will encourage the development of deep oil and gas reserves, and these are: (a) a five-year oil program for exploration wells over 2,000 metres that will provide royalty adjustments to offset higher drilling costs and provide a greater incentive for producers to continue to pursue new, deeper oil plays (these oil wells will qualify for up to a $1 million or 12 months of royalty offsets, whichever comes first); and (b) a five-year natural gas deep drilling program that will replace the existing program in order to encourage continued deep gas exploration for wells deeper than 2,500 metres (the program will create a sliding scale of royalty credit according to depth, of up to $3,750 per metre). These new programs are to be implemented along with the NRF.

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provided various incentives for exploring and developing oil reserves in Alberta. However, the Alberta Government announced in August of 2006 that four royalty programs were to be amended, a new program was to be introduced and the Alberta Royalty Tax Credit Program was to be eliminated, effective January 1, 2007. The programs affected by this announcement were: (i) Deep Gas Royalty Holiday; (ii) Low Productivity Well Royalty Reduction; (iii) Reactivated Well Royalty Exemption; and (iv) Horizontal Re-Entry Royalty Reduction. The program introduced was the Innovative Energy Technologies Program (the "**IETP**") which has a stated objective of promoting the producers' investment in research, technology and innovation for the purposes of improving environmental performance while creating commercial value. The IETP provides royalty reductions which are presumed to reduce financial risk. Alberta Energy decides which projects qualify and the level of support that will be provided. The deadline for the IETP's final round of applications was September 20, 2008. The successful applicants for the first two rounds have been announced, and those for the third round selection are scheduled to be announced in the first half of 2009. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

The NRF includes a policy of "shallow rights reversion". The Government of Alberta started to implement this policy on January 1, 2009, and its intent is to maximize the development of currently undeveloped resources that is consistent with the Government of Alberta's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's stated objective is for the mineral rights to shallow gas geological formations that are not being developed to revert back to the Government and be made available for resale, and in the event of non-productive shallow wells, to sever the rights from shallow zones and encourage increased production from up-hole zones. The shallow rights reversion policy affects all petroleum and natural gas agreements; however, the timing of the reversion will differ depending on whether the leases and licenses were acquired prior to January 1, 2009 or subsequent to January 1, 2009. Leases granted after January 1, 2009 will be subject to shallow rights reversion at the expiry of the primary term, and in the event of a licence the policy will apply at the expiry of the intermediate term. 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 lease or licence holder can make a request to extend this period. The order in which these agreements will receive the reversion notice will depend on the vintage of their term, with the older leases and licenses receiving a reversion notice first. Leases or licences that were granted prior January 1, 2009 but have not yet been continued will have a grace period until they are continued under section 15 of the *P&G Tenure Regulation* and be subject to deeper rights reversion prior to receiving a shallow rights reversion notice.

On March 3, 2009, the Government of Alberta announced a three-point incentive program to stimulate new and continued economic activity in Alberta which included a drilling royalty credit for new conventional oil and natural gas wells and a new well royalty incentive program. Under the drilling royalty credit program a $200 per metre royalty credit will be available on new conventional oil and natural gas wells drilled between April 1, 2009 and March 31, 2010, subject to certain maximum amounts. The maximum credits available will be determined by the company's production level in 2008 and its drilling activity between April 1, 2009 and March 31, 2010. The new well incentive program will apply to wells beginning production of conventional oil and natural gas between April 1, 2009 and March 31, 2010 and provides for a maximum 5% royalty rate for the first 12 months of production, up to a maximum of 50,000 barrels or 500 MMcf of natural gas.

The three-point incentive program also includes an investment of $30,000,000 by the Government of Alberta in abandonment and reclamation projects for orphan wells. The stated objective of this investment is to encourage the cleanup of inactive oil and gas wells and to stimulate new activity within the services sector.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments with respect to the Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands. The amount payable as a royalty in respect of oil depends on the type of oil, the value of the oil, the quantity of oil produced in a month, and the vintage of the oil. Generally, 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 rates are calculated in three stages, which take into account the vintage of the oil, if the oil produced has already been sold and any royalty exempt value applicable (exempt wells). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production or 11,450m^3 produced, whichever comes first; and the royalties for third-tier oil are the lowest reflecting the higher costs of exploration and extraction that the producers would incur. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the price obtained by the producer, and a prescribed minimum price. However, when the reference price is below the select price (a parameter used in the royalty rate formula), the royalty rate is fixed. As an incentive for the production and marketing of natural gas, which may have been flared, natural gas produced in association with oil has a lower royalty then the royalty payable on non-conservation gas.

On May 30, 2003, the Ministry of Energy and Mines for British Columbia announced an Oil and Gas Development Strategy for the Heartlands ("**Strategy**"). The Strategy is a comprehensive program to address road infrastructure, targeted royalties and regulatory reduction, and British Columbia service sector opportunities. In addition, the Strategy will result in economic and employment opportunities for communities in British Columbia's heartlands.

Some of the financial incentives in the Strategy include:

- Royalty credits towards the construction, upgrading, and maintenance of road infrastructure in support of resource exploration and development. Funding will be contingent upon an equal contribution from industry. This program has evolved over past years as a result of the Province's stated objective to increase competitiveness, and on March 2, 2009 the Government of British Columbia announced the 2009 Infrastructure Royalty Credit Program ("**Program**") which allocates $120 million in royalty credits for oil and gas companies. The Program provides access to royalty credits to oil and gas companies with respect to certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. Companies must apply to the Ministry of Energy and Mines for British Columbia prior to 2:00 p.m. on April 30, 2009 to be considered for approval under the program.

- Changes to provincial royalties: new royalty rates for low productivity natural gas to enhance marginally economic resources plays, royalty credits for deep gas exploration to locate new sources of natural gas, and royalty credits for summer drilling to expand the drilling season.

The British Columbia Energy Plan announced on February 27, 2007 outlines the requirements for the development of goals for conservation, energy efficiency and clean energy. In addition, its stated goal is to promote competitiveness through the implementation of a Net Profit Royalty Program ("**NPRP**") among others, and facilitate the development of the oil and gas industry. The NPRP's objective is to share the capital risk of successful developments. Pursuant to the *Net Profit Royalty Regulation*, the holder of a lease can apply to pay monthly net profit royalties on production of oil and for natural gas wells within a proposed project. The amount paid is calculated on the producer's interest in the project, and it ranges from 2% to 5% of the gross revenue and 15% to 35% of the net revenues received. In addition, it depends at which stage the well is, which may be either pre-payout, after-payout or already producing marketable gas.

The Government of British Columbia has introduced additional royalty programs, in addition to the ones previously mentioned, including a royalty program for deep discovery wells, royalty programs with a stated goal of attracting investment to less productive shallow gas wells (Ultra-Marginal Royalty Program), and the implementation of royalty credits to assist the development of the coalbed gas reserves found in the Province of British Columbia.

Saskatchewan

In Saskatchewan, the amount payable as a royalty in respect of oil depends on the vintage of the oil, the type of oil, the quantity of oil produced in a month, and the value of the oil. For Crown royalty and freehold production tax purposes, crude oil is considered "heavy oil", "southwest designated oil", or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil" introduced October 1, 2002, "third tier oil", "new oil" and "old oil") of oil production are applicable to each of the three crude oil types. The Crown royalty and freehold production tax structure for crude oil is price sensitive and varies between the base royalty rates of 5% for all "fourth tier oil" to 20% for "old oil". Marginal royalty rates are 30% for all "fourth tier oil" to 45% for "old oil".

The amount payable as a royalty in respect of natural gas is determined by a sliding scale based on a reference price (which is the greater of the amount obtained by the producer and a prescribed minimum price), the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. 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. The royalty and production tax classifications of gas production are "fourth tier gas" introduced October 1, 2002, "third tier gas", "new gas", and "old gas". The Crown royalty and freehold production tax for gas is price sensitive and varies between the base royalty rate of 5% for "fourth tier gas" and 20% for "old gas". The marginal royalty rates are between 30% for "fourth tier gas" and 45% for "old gas".

On October 1, 2002, the following changes were made to the royalty and tax regime in Saskatchewan:

- A new Crown royalty and freehold production tax regime applicable to associated natural gas (gas produced from oil wells) that is gathered for use or sale and is produced from: (a) oil wells with a finished drilling date on or after October 1, 2002, and (b) 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 cubic metres of gas for every cubic metre of oil. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65,000 cubic metres in a month. The associated natural gas royalty/tax regime will apply to gas produced from oil wells affected by concurrent production approvals after October 1, 2002 if the oil wells meet (a) or (b) above.

- A modified system of incentive volumes and maximum royalty/tax rates applicable to the initial production from oil wells and gas wells with a finished drilling date on or after October 1, 2002, was introduced. The incentive volumes are applicable to various well types and are subject to a maximum royalty rate of 2.5% and a freehold production tax rate of zero per cent.

- The elimination of the re-entry and short section horizontal oil well royalty/tax categories. All horizontal oil wells with a finished drilling date on or after October 1, 2002, will receive the "fourth tier" royalty/ tax rates and new incentive volumes.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a non-deep oil well qualifies for a 6,000 cubic metre incentive volume.

- A horizontal oil well, with a finished drilling date on or after October 1, 2002, that is a deep oil well qualifies for a 16,000 cubic metre incentive volume.

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

On June 19, 2007, the Government of Saskatchewan introduced the Orphan Well and Facility Liability Management Program pursuant to the amendment of the Oil and Gas Conservation *Act* and the *Oil and Gas Conservation Regulations*, 1985. The program includes a security deposit, which has two purposes: (i) preventing any person with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover the decommissioning and reclaiming of orphan properties. An additional change introduced is the mandatory licensing of all upstream oil and gas facilities in Saskatchewan.

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.

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. 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.

Environmental legislation in Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**"), which came into force on September 1, 1993, and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations, and significantly increased penalties. In 2006, the Alberta Government enacted regulations pursuant to the EPEA to specifically target sulphur oxide and nitrous oxide emissions from industrial operations including the oil and gas industry. In addition, the reduction emission guidelines outlined in the *Climate Change and Emissions Management Amendment Act* came into effect on July 1, 2007 ("**CCEMAA**"). Under this legislation, Alberta facilities emitting more than 100,000 tonnes of greenhouse gases a year must reduce their emissions intensity by 12%. Industries have three options to choose from in order to meet the reduction requirements outlined in this legislation, and these are: (i) by making improvement to operations that result in reductions; (ii) by purchasing emission credits from other sectors or facilities that have emissions below the 100,000 tonne threshold and are voluntarily reducing their emission; or (iii) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Industries can either choose one of these options or a combination thereof. Pursuant to CCEMAA and the *Specified Gas Emitters Regulation*, companies were obliged to reduce their emission intensity by 12% by March 31, 2008. Alberta industries have achieved 2.6 million tonnes of actual reduction, due to changes in operations and investing on verified offset projects. In addition, certain companies contributed $40 million to the Fund. It is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

On January 24, 2008, the Alberta Government announced a new climate change action plan that will cut Alberta's projected 400 million tonnes of emissions in half by 2050. This plan is based on three areas: (i) carbon capture and storage, which will be mandatory for *in situ* oil sand facilities that use heavy fuels for steam generation; (ii) energy conservation and efficiency; and (iii) greening production through increased investment in clean energy technology, including supporting research on new oil sands extraction processes, as well as the funding of projects that reduce the cost of separating carbon dioxide from other emissions supporting carbon capture and storage. In addition to this action plan, the Provincial Energy Strategy unveiled on December 11, 2008 is expected to, among other things, support the upgrading, refining and petrochemical clusters existing in the Province, market Alberta's energy internationally, review the emission targets and carbon charges applied to large facilities, and promote the innovation of energy technology by encouraging investment in research and development.

British Columbia's Environmental Assessment Act became effective June 30, 1995. This legislation rolls the previous processes for the review of major energy projects into a single environmental assessment process with public participation in the environmental review process. On February 27, 2007 the Government of British Columbia unveiled the Energy Plan outlining its strategy towards the environment and which includes targeting for zero net greenhouse gas emissions, promoting new investments in innovation, and becoming the world's leader in sustainable environmental management. For this purpose, on December 18, 2007 proposals were sought for applications to the Innovative Clean Energy Fund, in order to attract new technologies that will help solve energy and environmental issues. With regards to the oil and natural gas industry the objective is to achieve clean energy through conservation and energy efficient practices, whilst competitiveness is advocated in order to attract investment for the development of the oil and natural gas sector. Among the changes to be implemented are: (i) a new of Net Profit Royalty Program; (ii) the creation of a Petroleum Registry; (iii) the establishment of an infrastructure royalty program (combining roads and pipelines); (iv) the elimination of routine flaring at producing wells; (v) the creation of policies and measures for the reduction of emissions; (vi) the development of unconventional resources such as tight gas and coalbed gas; and (vii) new the Oil and Gas Technology Transfer Incentive Program that encourages the research, development and use of innovative technologies to increase recoveries from existing reserves and promotes responsible development of new oil and gas reserves. Furthering these initiatives, the Government of British Columbia introduced on July 1, 2008, revenue-neutral carbon tax legislation that is applied to all fossil fuels used in the Province of British Columbia. The tax would be phased in, and the initial rate would be based on CO2e of $10 per tonne for the first six months of 2009 and $15 per tonne for the last six months of 2009, following $5 per tonne increases on July of every year until 2012. Tax credits and reductions will be used in order to offset the tax revenues that the Government of British Columbia would receive otherwise. On April 3, 2008, the Government of British Columbia introduced the Greenhouse Gas Reduction (Cap and Trade) Act which will allow participation in the Western Climate Initiative cap and trade systems being developed. The system establishes a limit on emissions, and allows regulated emitters to buy/sell emission allowances or offset emits. The emitter is obliged to obtain emission allowances (compliance units) equal to the amount of greenhouse gases emitted within a certain period of time, and that are supposed to be surrendered to the Government of British Columbia as compliance proof.

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"). The Kyoto Protocol calls for Canada to reduce its greenhouse gas emissions to 6% below 1990 "business-as-usual" levels between 2008 and 2012. Given revised estimates of Canada's normal emissions levels, this target translates into an approximately 40% gross reduction in Canada's current emissions. It is questionable, based on the Updated Action Plan announced by the Federal Government (see below), that the Kyoto Protocol target of 6% below 1990 emission levels will be enforced in Canada. Bill C-288, which is intended to ensure that Canada meets its global climate change obligations under the Kyoto Protocol, was passed by the House of Commons on February 14, 2007. On April 26, 2007, the Federal Government released its Action Plan to Reduce Greenhouse Gases and Air Pollution (the "**Action Plan**") also known as ecoACTION which includes the regulatory framework for air emissions. This Action Plan covers not only large industry, but regulates the fuel efficiency of vehicles and the strengthening of energy standards for a number of energy using products.

The Government of Canada and the Province of Alberta released on January 31, 2008 the final report of the Canada-Alberta ecoENERGY Carbon Capture and Storage Task Force, which recommends among others: (i) incorporating carbon capture and storage into Canada's clean air regulations; (ii) allocating new funding into projects through competitive process; and (iii) targeting research to lower the cost of technology.

In order to strengthen the Action Plan, on March 10, 2008, the Government of Canada released "Turning the Corner – Taking Action to Fight Climate Change" (the "**Updated Action Plan**") which provides some additional guidance with respect to the Government's plan to reduce greenhouse gas emissions by 20% by 2020 and by 60% to 70% by 2050.

The Updated Action Plan is primarily directed towards industrial emissions from certain specified industries including the oil sands, oil and gas and refining. The Updated Action Plan is intended to create a carbon emissions trading market, including an offset system, to provide incentive to reduce greenhouse gas emission and establish a market price for carbon. There are mandatory reductions of 18% from the 2006 baseline starting in 2010 and an additional 2% in subsequent years for existing facilities. This target will be applied to regulated sectors on a facility-specific, sector-wide or corporate basis; in the case of oil sands production, petroleum refining, natural gas pipelines and upstream oil and gas the target will be considered facility-specific (sectors in which the facilities are complex and diverse, or where emissions are affected by factors beyond the control of the facility operator). Emissions from new facilities, which are those built between 2004 and 2011, will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time, and will be granted a 3-year grace period during which no emissions intensity targets will apply. Targets will begin to apply on the fourth year of commercial operation and the baseline will be the third year's emissions intensity, with a 2% continuous annual emission intensity improvement required. The definition of new facility also includes Greenfield facilities, major expansions constituting more than a 25% increase in a facility's physical capacity, as well as transformations to a facility that involve significant changes to its processes. For upstream oil and gas and natural gas pipelines, it will be applied using a sector-specific approach. For the oil sands, its application will be process-specific, oil sands plants built in 2012 and later, those which use heavier hydrocarbons, up-graders and *in-situ* production will have mandatory standards in 2018 that will be based on carbon capture and storage.

In the following regulated sectors, the Updated Action Plan will apply only to facilities exceeding a minimum annual emissions threshold: (i) 50,000 tonnes of CO_2 equivalent per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalent per upstream oil and gas facility; and (iii) 10,000 boe/d/company. These proposed thresholds are significantly stricter than the current Alberta regulatory threshold of 100,000 tonnes of CO_2 equivalent per year per facility.

Four separate compliance mechanisms are provided in respect of the above targets: Technology Fund contributions, offset credits, clean development credits and credits for early action. The most significant of these compliance mechanisms, at least initially, will be the Technology Fund and for which regulated entities will be able to contribute in order to comply with emissions intensity reductions. The contribution rate will increase over time, beginning at $15 per tonne for the 2010-12 period, rising to $20 per tonne in 2013, and thereafter increasing at the nominal rate of GDP growth. Contribution limits will correspondingly 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 mentioned 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 cancel the offset credits or bank them 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. 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.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not currently possible to predict either the nature of those requirements or the impact on us and our operations and financial condition at this time.

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 ratability 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 and special meeting of Unitholders to be held on May 20, 2009. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2008 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:

Baytex Energy Trust
2200, 205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: (403) 269-4282
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, 2008, 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 9, 2009

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, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, 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, 2008, 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 (County or Foreign Geographic Area)	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, 2008). Prepared October 2008 to February 2009.	Canada and the United States	Nil	$3,478.8	Nil	$3,478.8

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:

Sproule Associates Limited
Calgary, Alberta
March 4, 2009

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

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

(signed) "*Michael W. Maughan*"
Michael W. Maughan, C.P.G., P.Geol.
Vice-President, Geoscience

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 its responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board of director approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee are as follows:

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

2. To provide better communication between directors and external auditors;

3. To enhance the external auditor's independence;

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

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

MEMBERSHIP OF COMMITTEE

1. The Committee shall be comprised of at least three (3) directors of Baytex, none of whom are members of management of Baytex and all of whom are "independent" (within the meaning of National Instrument 52-110 "Audit Committees" ("NI 52-110").

2. The Board of Directors shall have the power to appoint the Committee Chairman, who shall be an unrelated director.

3. All of the members of the Committee shall be "financially literate". The Board has adopted the definition for "financial literacy" used in NI 52-110.

MEETINGS

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. 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.

3. Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The Chief Financial Officer shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

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

5. The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the audit Committee consider appropriate.

MANDATE AND RESPONSIBILITIES OF 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.

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:

   - 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 annual financial statements of the Trust prior to their submission to the board of directors for approval. The process should include but not be limited to:

   - 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; and
   - obtain explanations of significant variances with comparative reporting periods.

4. The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to board approval. The Committee must be satisfied that adequate procedures are in place for the review of the Trust's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

5. With respect to the appointment of external auditors by the board, the Committee shall:

   - recommend to the board the appointment of the external auditors;
   - recommend to the board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;
   - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

- review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors; and

- determine through inquiry if there are any related party transactions and ensure the nature and extent of such transactions are properly disclosed.

6. Review with external auditors (and 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 their 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 non-audit services to be provided to the Trust or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre-approve non-audit 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 risk management policies and procedures of the Trust (i.e. hedging, litigation and insurance).

9. The Committee shall establish a procedure 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 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 are to cooperate as requested by the Committee.

12. The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of the Trust without any further approval of the board.