BAYTEX ENERGY TRUST

ANNUAL INFORMATION FORM

2007

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APPENDICES:

SELECTED TERMS

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

Entities

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

Baytex ExchangeCo means Baytex ExchangeCo Ltd.

Board of Directors means the board of directors of Baytex.

Crew means Crew Energy Inc.

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.

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

Sproule Report means the report dated March5, 2008 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Trust as of December 31, 2007*".

Securities and Other Terms

DRIP means our distribution reinvestment plan.

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

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 principals.

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 net profit interest agreement, as amended and restated, between us and Baytex providing for the creation of the NPI.

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

Support Agreement means the support agreement between us, Baytex, Baytex ExchangeCo and the Trustee.

Trust Indenture means the amended and restated trust indenture between us and Baytex made as of September 2, 2003.

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.

Voting and Exchange Trust Agreement means the voting and exchange trust agreement entered into on September 2, 2003 between us, Baytex ExchangeCo and the Trustee.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
NGL	natural gas liquids
Stb	stock tank barrels of oil
Mstb	thousand stock tank barrels of oil
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.
psi	means pounds per square inch.
ARTC	means Alberta Royalty Tax Credit.
$ 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 generally accepted accounting principles in Canada. 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

Regarding Forward Looking Statements

Certain statements contained in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form, constitute forward-looking statements within the meaning of applicable securities laws, including section 21E of the *United States Securities Exchange Act of 1934*, as amended, and section 27A of the *United states Securities Act of 1933*, as amended. These statements relate to future events or our future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "should", "believe" and similar expressions are not historical facts and are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas assets;
- oil and natural gas production levels;
- our drilling plans for our Heavy Oil District and Conventional Oil and Gas District projects;

- the size of our oil and natural gas reserves;
- projections of market prices and costs and the related sensitivities of distributions;
- supply and demand for oil and natural gas;
- expectations regarding our ability to raise capital and to continually add to reserves through acquisitions and development;
- treatment under governmental regulatory regimes and tax laws;
- capital expenditure programs;
- the existence, operation and strategy of our commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed by us;
- our acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- the impact of Canadian federal and provincial governmental regulation on us relative to other oil and gas issuers of similar size;
- our ability to grow or sustain production and reserves through prudent management and acquisitions;
- the emergence of accretive growth opportunities; and
- our ability to benefit from the combination of growth opportunities and the ability to grow through capital markets.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form, and in certain documents incorporated by reference into this Annual Information Form:

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating oil and natural gas reserves;
- risks inherent in oil and gas activities;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of, or failure to realize the anticipated benefits, of acquisitions;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;
- geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves;

- changes in income tax laws or changes in tax or environmental laws and incentive programs or royalty regimes relating to the oil and gas industry and income trusts; and

- the other factors discussed under "*Risk Factors*".

Statements relating to "reserves" or "resources" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference, including factors discussed under "*Management's Discussion and Analysis of Financial Condition and Results of Operation*" herein are expressly qualified by this cautionary statement and are available on SEDAR at *www.sedar.com*. You should also carefully consider the matters discussed under the heading "*Risk Factors*" in this Annual Information Form.

Further, any forward-looking statement speaks only as of the date on which such statement is made, and, except as required by applicable securities laws, we undertake no obligation to update any forward-looking statement or statements to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events. New 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.

Description of Cash Flow from Operations

This Annual Information Form refers 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 Canadian 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 earnings or other measures of financial performance calculated in accordance with Canadian GAAP.

For more information, see our "*Management's Discussion and Analysis*" which includes a definition of "cash flow from operations" and reconciliation to cash provided by operating activities, which has been filed on SEDAR at www.sedar.com.

Access to Documents

Any document referred to in this Annual Information and described as being filed on SEDAR 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-end unincorporated investment trust created under the laws of the Province of Alberta and created 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.

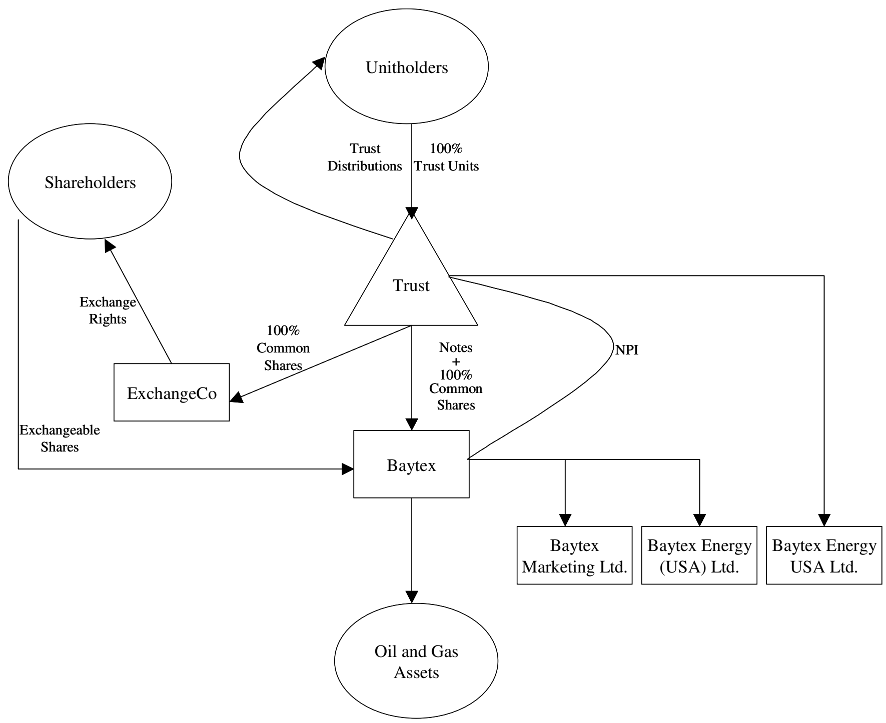
Inter-Corporate Relationships

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 USA Ltd.	100%	Colorado
Baytex ExchangeCo Ltd.	100%	Alberta
Baytex Marketing Ltd.	100%	Alberta
Baytex Energy (USA) Ltd.	100%	Delaware

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) Baytex had a total of 1,565,615 Exchangeable Shares issued and outstanding as at December 31, 2007, which were exchangeable into 2,628,902 Trust Units.

(3) 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

On October 31, 2006, the Finance Minister announced the federal government's plan regarding taxation of income trusts and certain other "specified flow-through investment entities" ("**SIFTs**"). Currently, distributions paid to unitholders, other than returns of capital, are claimed as a deduction by income trusts in arriving at taxable income whereby tax is eliminated at the trust level and is paid by the unitholders.

The income trust tax legislation relating to SIFTs (the "**SIFT Rules**"), which received Royal assent on June 22, 2007, will result in a two-tiered tax structure whereby distributions from an income trust would first be subject to income taxes commencing in 2011 (or earlier, if any such income trust exceeds the normal growth guidelines announced by the Minister on December 15, 2006), and then unitholders would be subject to tax on the distribution as if it were a taxable dividend paid by a taxable Canadian corporation.

On October 30, 2007, the Finance Minister announced, as part of the 2007 Economic Statement, changes to the tax system including reduction of the corporate income tax rate to 15 percent by 2012. Legislation enacting the measures, announced in the Economic Statement, received Royal assent on December 14, 2007. The reduction in the general corporate tax rate will also be reflected in a lower tax rate on trust distributions.

Currently, the SIFT Rules provide that the SIFT tax rate will be the federal general corporate income tax rate (which is anticipated to be 16.5 percent in 2011 and 15 percent in 2012) plus the provincial SIFT tax factor (which is set at a fixed rate of 13 percent). On February 26, 2008, the Minister of Finance announced (the "**Provincial SIFT Tax Proposal**") that instead of basing the provincial component of the SIFT tax on a flat rate of 13 percent, the provincial component will instead be based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment. Under the Provincial SIFT Tax Proposal, we would likely be considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be 10 percent. There can be no assurance, however, that the Provincial SIFT Tax Proposal will be enacted as proposed.

On December 20, 2007, the Finance Minister announced technical amendments to provide some clarification to the SIFT Rules. As part of the announcement the Minister indicated the federal government intends to provide, in 2008, legislation to permit income trusts to convert to taxable Canadian corporations without any undue tax consequences to investors or the income trusts.

Our Board of Directors and management continue to review the impact of the SIFT Rules on our business strategy and the merits of converting to a corporation on or before January 1, 2011. We expect future technical interpretations and details will further clarify the legislation. At the present time, we believe that if structural or other similar changes are not made, the after-tax distribution amount in 2011 to taxable Canadian investors will remain approximately the same; however, the after-tax distribution will decline for both tax-deferred Canadian investors and foreign investors.

For more information, see "*Risk Factors – We may be impacted by recent Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – 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. The estimated fair market value at September 2, 2003 of the securities issued pursuant to the reorganization was $11.76 per Trust Unit and $0.55 per one-third of a common share of Crew.

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 pre-transaction 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 6.5% 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 a net cash consideration of $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 Tangleflags, Our second largest producing area within our heavy oil operations. 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 a net cash consideration of $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.

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 total cash consideration of $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 included 26,000 net acres of undeveloped land in the Pembina area. Lindbergh is a project that offers a large heavy oil resource in place that is amenable to primary (cold) production. Its shallow-depth and multiple zone character provide a low-cost source of recompletion and drilling inventory 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.

Significant Acquisitions

The acquisition of the properties at Pembina and Lindbergh as described above was a significant acquisition for which disclosure was required under Part 8 of National Instrument 51-102. We filed a Business Acquisition Report on Form 51-102F4 on June 24, 2007 in respect of the acquisition, a copy of which is available on our SEDAR profile at *www.sedar.com*.

Trends

Crude oil and natural gas prices are volatile and subject to a number of external factors. Natural gas is a commodity 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, Organization of the Petroleum Exporting Countries' ability to adjust supply to world demand and weather. Crude oil prices have been 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 have 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, and the continued 2007 strengthening of the Canadian dollar somewhat mitigated the economic benefit of higher 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, acquisitions 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.

Efforts of trusts to replace annual production declines have resulted in continued 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 economically replace production through internal development drilling should 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*","*Risk Factors – We may be impacted by recent Federal Tax Changes for Income Trusts and Corporations*".

RISK FACTORS

The following is a summary of material risk factors relating to our business.

We are dependent on Baytex for our revenue

We are an open-ended, limited purpose trust, which is entirely dependent upon the operations and assets of Baytex through our ownership of the common shares, the Notes and the NPI. Accordingly, cash distributions to Unitholders will be dependent upon the ability of Baytex to meet its interest and principal repayment obligations under the Notes to declare and pay dividends on the common shares, and to pay the NPI. Baytex's income will be received from the production of oil and natural gas from Baytex's existing resource properties and will be 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 may be adversely affected.

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.

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 income otherwise distributable to us.

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 will 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 may be 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. In the event such entities fail to meet their contractual obligations to us, such failures could have a material adverse effect on us and our cash flow from operations. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner.

Our 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. Oil and natural gas prices have fluctuated widely during recent years and are determined by economic and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions, in the United States and Canada, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, 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 gas would have an adverse effect on our carrying value of our proved and probable reserves, borrowing capacity, revenues, profitability and cash flows from operating activities. 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, 2007, our balance sheet reflected $34.2 million of unrealized losses 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.

Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects. See "*Risk Factors – We may not realize anticipated benefits of acquisitions and dispositions or manage our growth*" and "*Risk Factors – Project delays may delay expected revenues from operations*".

Distributions may be affected by capital expenditures

The timing and amount of capital expenditures will directly affect the amount of income 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.

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 distributions to Unitholders.

Debt Service

We may not be successful in obtaining additional credit or complying with our debt service charges.

Baytex has credit facilities in the amount of $370 million. 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 any amounts to us. Although it is believed that the bank line of credit is sufficient, there can be no assurance that the amount will be adequate for the financial obligations of Baytex or that additional funds can be obtained.

The lenders have been provided with security over substantially all of the assets of Baytex. If Baytex becomes unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, the lenders may foreclose on or sell the properties free from or together with the NPI.

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 its obligations under Baytex's credit facilities or upon a material borrowing base shortfall or default.

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.

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. All such estimates are to some degree speculative, and classifications of reserves are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves 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.

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 will be more 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.

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

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, which may be amended from time to time to impose higher standards and potentially more costly obligations on us. 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. Such legislation may be changed to impose higher standards and potentially more costly obligations on us. 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. There can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations.

Furthermore, management of Baytex 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. In particular there is uncertainty regarding the *Government of Canada's Clean Air Act of 2006*. The Clean Air Act proposes to reduce greenhouse gas emissions, however emission targets and compliance deadlines differ from those outlined in the Kyoto Protocol which was ratified by Canada. If passed, the Clean Air Act may have adverse operational and financial implications to us. See "*Industry Conditions – Environmental Regulation*". Based on our current knowledge, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations.

Provincial emission reduction requirements, such as those in Alberta's *Climate Change* and *Emissions Management Amendment Act*, may require the reduction of emissions or emissions intensity of our operations and facilities. The direct or indirect costs of these regulations may adversely and materially affect our business. See "*Industry Conditions – Environmental Regulation*".

Canada is a signatory to the United Nations Framework Convention on Climate Change and in December 2002 the Government of Canada ratified the Kyoto Protocol and it became legally binding on February 16, 2005. This protocol calls for Canada to reduce its greenhouse gas emissions to six percent below 1990 levels during the period between 2008 and 2012. Our exploration and production facilities and other operations and activities emit greenhouse gases that may subject us to legislation regulating emissions of greenhouse gases. The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas exploration and production. There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. 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 either the nature of those requirements or the impact on us and our operations and financial condition. See "*Risk Factors – Our revenues are affected by changes in regulations*".

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 or a material increase in the costs of production, development or exploration activities or otherwise adversely affect our financial condition, results of operations or prospects. Future changes in other environmental legislation could occur and result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition or results of operations. See "*Industry Conditions – Environmental Regulation*".

We may have delays in cash receipts

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.

Our reserves may become depleted

We have certain unique attributes that differentiate us from other oil and gas industry participants. Distributions of distributable income in respect of properties, absent commodity price increases or cost effective acquisition and development activities will decline over time in a manner consistent with declining production from typical oil, natural gas and natural gas liquids reserves. We will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, our initial production levels and reserves will decline and the level of distributable income will be reduced.

Our future oil and natural gas reserves and production, and therefore our cash flows from operating activities, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through acquisition or development activities, our reserves and production will decline over time as reserves are produced.

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 natural gas reserves will be impaired. To the extent that we required to use cash flow to finance capital expenditures or property acquisitions, the level of distributable income will be reduced.

There can be no assurance that we will be successful in developing or acquiring additional reserves on terms that meet our investment objectives.

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 addition, the exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 12 months, resulting in our receipt of fewer Canadian dollars for our production which may affect future distributions. 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. 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. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of our reserves as determined by our independent evaluator.

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.

We are affected by political events

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

In addition, our oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it could have a material adverse effect on our financial condition. We do not have insurance to protect against the risk from terrorism.

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.

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

We 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 operation. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that we can focus our 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. Any such instance may offset the return on and value of the Trust Units. 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. In the future, we may acquire oil and gas properties outside of this geographic area. In addition, the Trust Indenture does not limit our activities 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.

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 are issued from treasury which may result in a decline in production per Trust Unit 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 – 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 operating activities to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of cash flow from operating activities available for distribution to Unitholders will be reduced.

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.

Our prior distributions may not be reflective of future distributions

Our historical distributions may not be reflective of future distribution payments, which will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time. The actual amount distributed, if any, is dependent on the commodity price environment and is at the discretion of the Board of Directors. Distributable cash available for distribution is not an earnings measure recognized by generally accepted accounting principles and is not necessarily comparable to the measurement of distributable cash available for distribution in other similar trust entities.

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 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 *Income Tax Act* (Canada), the Trust Units will cease to be qualified investments for registered retirement savings plans, registered education savings plans, deferred profit sharing plans and registered retirement income funds.

We expect that it will continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada). 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 *Income Tax Act* (Canada)). There can be no assurance that such circumstances would not detrimentally affect 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 it 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 not constitute qualified investments for registered retirement savings plans ("**RRSPs**"), registered retirement income funds ("**RRIFs**"), registered education savings plans ("**RESTPs**") or deferred profit sharing plans ("**DPSPs**"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to one percent of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Customs and Revenue Agency.

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 *Income Tax Act* (Canada). See "*Additional Information Respecting Baytex Energy Trust – Trust Indenture – Non-resident Unitholders*".

The New Alberta Royalty Regime may impact our Revenues

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" ("**NRF**") containing the government's proposals for Alberta's new royalty regime which is scheduled to be effective on January 1, 2009.Given that the NRF has only recently been announced, it is not possible at this time to determine the full impact of the NRF on our financial condition and operations and in particular the extent to which the proposed new royalty regime will reduce our cash flow, which will in turn reduce the cash otherwise available for distribution by us to our Unitholders.

The NRF includes the following features:

- New, simplified royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity. The formulas eliminate the need for conventional oil and natural gas tiers and several royalty exemption programs.

- A sliding scale will be implemented for oil sands royalty rates ranging from one to nine percent pre-payout and 25 to 40 percent post-payout depending on the price of oil.

- The province will exercise its existing right to receive "royalty-in-kind" on oil sands projects (i.e. raw bitumen delivered to the Crown-operated Alberta Petroleum Marketing Commission in lieu of cash royalties).

- The government will ensure that eligible expenditures and definitions of oil sands projects (also known as "ring fence" definition) that determine when a project has reached payout are tightly and clearly defined. Environmental "costs of doing business" will continue to be recognized as eligible expenditures.

- No grandfathering will be implemented for existing oil sands projects.

- Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009.

We cannot provide any assurance that the NRF will be implemented in the form proposed. If changes are made to the NRF before it is implemented by the Alberta government, such changes could result in the implementation of a new royalty regime that impacts us in a materially different manner, and that is more adverse to us, than the NRF as currently proposed. See "*Industry Conditions*" and "*Risk Factors – Our revenues are affected by changes in regulations*".

We may be impacted by recent Federal Tax Changes for Income Trusts and Corporations

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

Generally, there will be a four year transition period for an existing trust, 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. "Normal growth" includes equity growth within certain "safe harbour" limits, measured by reference to a SIFT trust's market capitalization as of the end of trading on October 31, 2006 (which would include only the market value of the SIFT's 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. Moreover, 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 2007 and an additional approximately $365 million for each of 2008, 2009 and 2010 with any unused amount rolling forward to the next year.

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 our management believes that the SIFT Rules: (a) substantially eliminates 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 "*Risk Factors – Our revenues are affected by changes in regulations*".

We have non-resident ownership restrictions of our Trust Units

We intend to comply with the requirements under the *Income Tax Act* (Canada) 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 *Income Tax Act* (Canada). 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 *Income Tax Act* (Canada) 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 "*Information Relating To Us – The Trust Indenture – Limitations on Non-Resident Ownership*" and "*Risk Factors – Our status as a mutual fund trust may be changed or affected by changes in legislation*".

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 distributions available to us. We believe that the interest expense inherent in our structure is supportable and reasonable in light of the terms of the Notes.

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 and results of operations. 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 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 price per Trust Unit is a function of anticipated distributable income, the properties acquired by us and our ability to effect long-term growth in our value. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and our ability to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

The Trust Units are 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 a 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 – Redemption Right*".

Trust Units will have no value when we can no longer economically produce 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.

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 the issuers of the investment vehicle, 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.

Our directors and officers may have conflicts

The directors and officers of Baytex 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, the directors and officers of Baytex 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 Baytex and a director or officer of Baytex.

Accounting policies may impact our financial statements

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

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flows from reserves. If net capitalized costs exceed the estimated recoverable amounts, we will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings. The net value of oil and gas properties are highly dependent upon the prices of oil and natural gas. See "*Risk Factors – Our business depends on volatile oil and gas prices*".

GAAP requires that goodwill balances be assessed at least annually for impairment and that any permanent impairment be charged to net income. A permanent reduction in reserves, decline in commodity prices, and/or reduction in the Trust Unit price may indicate a goodwill impairment. As at December 31, 2007 we had $37.8 million of goodwill recorded on our balance sheet. An impairment would result in a write-down of the goodwill value and a non-cash charge against net income. The calculation of impairment value is subject to management estimates and assumptions.

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

Risks Particular to United States and Other Non-Resident Unitholders

In addition to the risk factors set forth above, the following risk factors are particular to Unitholders who are not residents of Canada.

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

The *Income Tax Act* (Canada) and the tax treaties between Canada and other countries may impose additional 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. For instance, since January 1, 2005, a 15 percent withholding tax is applied to return of capital portion of distributions made to non-resident unitholders.

The ability of United States and other non-resident Unitholders 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 some of 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.

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 Securities and Exchange Commission of the United States (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 included in this Annual Information Form estimates of 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.

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.

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

Overview

We are an open-end unincorporated investment trust governed by the laws of the Province of Alberta and created 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 *Income Tax Act* (Canada)) 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 *Income Tax Act* (Canada).

Our principal undertaking is to issue Trust Units and other securities and to acquire and hold net profits interests, royalties and other interests. Baytex carries 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 Baytex 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.

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 its obligations under Baytex's facilities or upon a material borrowing base shortfall or default.

Our current distribution policy targets the use of between 40 percent and 50 percent of our available cash for capital expenditures to fund both exploration and development expenditures and minor property acquisitions, but excludes major acquisitions. 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 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 Exchangeable Shares are owned by the public.

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 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 ninety-nine (99 percent) 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 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 Notes are unsecured, payable on demand and bear 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 Note Trustee appointed under the Trust Indenture to exercise the powers and remedies available under the Note Indenture upon an event of default and, with the Trust, 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 us flexibility to delay payments of interest or principal otherwise due to it while payment is made to other noteholders, and to allow other noteholders to be paid out before the Trust. 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 (the "**Statement**") is dated December 31, 2007. The statement is effective as of December 31, 2007 and the preparation date of the Statement by Sproule is March 5, 2008. 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, 2007 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.

All of our reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia and Saskatchewan.

Due to uncertainties and lack of sufficient details with which to determine royalties for some product types under the proposed Alberta new royalty regime ("NRF"), the reserves data set forth below has been prepared using the existing royalties. See "*Industry Conditions – Provincial Royalties and Incentives – Alberta*" and "*Risk Factors – The New Alberta Royalty Regime may impact our Revenues*".

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*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

	RESERVES					
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)
PROVED:						
Developed Producing	5,916.8	4,905.2	23,069.0	19,827.0	78.3	64.4
Developed Non-Producing	546.4	448.8	23,830.9	19,935.6	10.1	8.5
Undeveloped	3,574.0	2,947.7	38,168.8	33,860.2	15.6	12.5
TOTAL PROVED	10,037.2	8,301.7	85,068.7	73,622.8	104.0	85.4
PROBABLE	5,294.7	4,262.7	37,392.6	32,159.9	44.9	36.6
TOTAL PROVED PLUS PROBABLE	15,331.9	12,564.4	122,461.3	105,782.7	148.9	122.0

	RESERVES			
	NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	2,852.6	2,254.0	44,892.8	37,721.8
Developed Non-Producing	372.4	323.6	26,425.7	22,119.2
Undeveloped	378.4	286.6	44,719.1	39,185.2
TOTAL PROVED	3,603.4	2,864.2	116,037.6	99,026.2
PROBABLE	1,869.6	1,417.4	52,038.4	43,943.6
TOTAL PROVED PLUS PROBABLE	5,473.0	4,281.6	168,076.0	142,969.8

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year) (1)(2)				
RESERVES CATEGORY	0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED:					
Developed Producing	1,249,418	1,097,754	981,727	892,901	822,842
Developed Non-Producing	669,836	463,529	340,355	261,874	209,054
Undeveloped	966,148	680,530	494,762	368,426	279,260
TOTAL PROVED	2,885,402	2,241,813	1,816,844	1,523,201	1,311,156
PROBABLE	1,483,442	963,497	677,423	505,903	395,681
TOTAL PROVED PLUS PROBABLE	4,368,844	3,205,310	2,494,267	2,029,104	1,706,837

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by approximately 1.8 percent to 2.1 percent using a 10% discount rate and using the Sproule forecast prices set forth in this Annual Information Form. See "*Industry Conditions*" and "*Risk Factors – The New Alberta Royalty Regime may impact our Revenues*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) since we do not have a substantial volume of solution gas, application of the new conventional gas royalty formula on solution gas production will not be material to our overall net percent value so no changes were made; and (iii) in the case of deep gas, Sproule assumed that the deep gas royalty

adjustment applies to all existing and future wells in the high case and for the low case Sproule assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000)	5% ($000)	10% ($000)	15% ($000)	20% ($000)
PROVED:					
Developed Producing	1,249,418	1,097,754	981,727	892,901	822,842
Developed Non-Producing	669,836	463,529	340,355	261,874	209,054
Undeveloped	728,647	530,433	396,034	301,243	232,198
TOTAL PROVED	2,647,901	2,091,716	1,718,116	1,456,018	1,264,094
PROBABLE	1,073,224	699,261	496,730	376,596	299,855
TOTAL PROVED PLUS PROBABLE	3,721,125	2,790,977	2,241,846	1,832,614	1,563,949

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000)	ROYALTIES ($000)	OPERATING COSTS ($000)	DEVELOPMENT COSTS ($000)	WELL ABANDONMENT COSTS ($000)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000)	INCOME TAXES ($000)	FUTURE NET REVENUE AFTER INCOME TAXES ($000)
TOTAL PROVED	5,974,414	867,625	1,698,246	427,132	96,009	2,885,402	237,501	2,647,901
TOTAL PROVED PLUS PROBABLE	8,874,034	1,305,611	2,533,914	535,314	130,355	4,368,844	647,720	3,721,125

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2007
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) [(1)(2)] ($000s)	UNIT VALUE ($/boe) [(3)]
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	306,436	34.34
	Heavy Oil (including solution gas and other by-products)	1,271,740	17.12
	Natural Gas (including by-products but excluding natural gas from oil wells)	238,668	15.50
	Total	1,816,844	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	439,175	32.33
	Heavy Oil (including solution gas and other by-products)	1,718,876	16.11
	Natural Gas (including by-products but excluding natural gas from oil wells)	336,217	15.20
	Total	2,494,268	

Notes:

(1) Management has estimated that the impact of the NRF is to decrease the net present values of future net revenue (before income taxes) by approximately 1.8 percent to 2.1 percent using a 10% discount rate and using the Sproule forecast prices set forth in this Annual Information Form. See "*Industry Conditions*" and "*Risk Factors – The New Alberta Royalty Regime may impact our Revenues*".

(2) The methodology used to calculate the new royalties for the net present value of future net revenue amounts set forth in Note (1) was based on the following criteria: (i) in the case of heavy oil, a heavy oil par price was used for the high case and for the low case the light oil par price was used; (ii) since we do not have a substantial volume of solution gas, application of the new conventional gas royalty formula on solution gas production will not be material to our overall net percent value so no changes were made; and (iii) in the case of deep gas, Sproule assumed that the deep gas royalty adjustment applies to all existing and future wells in the high case and for the low case Sproule assumed that the deep gas royalty adjustment only applies to wells drilled after 2008.

(3) 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.

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

6. "**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.

7. "**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.

8. "**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.

9. "**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.

10. "**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).

11. Numbers may not add due to rounding.

12. 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, 2007, 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, 2007

	OIL					
	WTI Cushing Oklahoma ($US/Bbl)	**Edmonton Par Price 40° API ($Cdn/Bbl)**	**Hardisty Heavy 12° API ($Cdn/Bbl)**	**NATURAL GAS AECO Gas Price ($Cdn/Mmbtu)**	**INFLATION RATES [(1)] %/year**	**EXCHANGE RATE [(2)] ($US/$Cdn)**
Historical						
2003	31.14	43.23	27.39	6.66	2.5	0.716
2004	41.42	52.91	30.40	6.87	1.3	0.770
2005	56.46	69.29	34.35	8.58	1.6	0.826
2006	66.09	73.31	43.32	7.16	1.5	0.882
2007	72.27	77.06	44.75	6.65	2.0	0.935
Forecast						
2008	89.61	88.17	54.67	6.51	2.0	1.000
2009	86.01	84.54	52.42	7.22	2.0	1.000
2010	84.65	83.16	51.56	7.69	2.0	1.000
2011	82.77	81.26	50.38	7.70	2.0	1.000
2012	82.26	80.73	50.05	7.61	2.0	1.000
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, 2007, excluding hedging activities were \$6.61/Mcf for natural gas, \$65.53/Bbl for light oil and NGL, and \$44.28/Bbl for heavy oil. The heavy oil price includes the effect of our long term sales contract.

Reserves Reconciliation

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

	LIGHT AND MEDIUM OIL			HEAVY OIL		
	Proved (Mbbl)	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2006	5,185.6	2,043.6	7,229.2	75,809.0	32,929.4	108,738.4
Discoveries	-	-	-	-	-	-
Extensions	72.0	20.8	92.8	8,251.6	3,187.5	11,439.1
Infill Drilling	-	-	-	-	-	-
Improved Recovery	328.6	322.3	650.9	3,361.9	1,127.1	4,489.0
Technical Revisions	(343.1)	(2,463.0)	(2,806.1)	1,987.9	(1,013.8)	974.1
Acquisitions	6,081.1	5,292.4	11,373.5	2,996.7	769.7	3,766.4
Dispositions	-	-	-	-	-	-
Economic Factors	113.9	78.6	192.5	725.2	392.7	1,117.9
Production	(1,400.9)	-	(1,400.9)	(8,063.6)	-	(8,063.6)
December 31, 2007	10,037.2	5,294.7	15,331.9	85,068.7	37,392.6	122,461.3

	ASSOCIATED AND NON-ASSOCIATED GAS			NATURAL GAS LIQUIDS		
	Proved (MMcf)	**Probable (MMcf)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2006	108,421	39,635	148,056	3,462.2	1,013.7	4,475.9
Discoveries	2,275	586	2,861	9.0	2.3	11.3
Extensions	3,680	977	4,657	79.9	41.2	121.1
Infill Drilling	-	-	-	-	-	-
Improved Recovery	2,767	718	3,485	-	-	-
Technical Revisions	(7,146)	(5,829)	(12,975)	(197.8)	169.8	(28.0)
Acquisitions	11,871	8,140	20,011	838.3	637.5	1,475.8
Dispositions	-	-	-	-	-	-
Economic Factors	1,038	661	1,699	12.2	5.1	17.3
Production	(18,937)	-	(18,937)	(600.4)	-	(600.4)
December 31, 2007	103,969	44,888	148,857	3,603.4	1,869.6	5,473.0

	OIL EQUIVALENT		
	Proved (Mboe)	**Probable (Mboe)**	**Proved (Mboe)**
December 31, 2006	102,527.0	42,592.6	145,119.6
Discoveries	388.1	100.0	488.1
Extensions	9,016.8	3,412.3	12,429.1
Infill Drilling	-	-	-
Improved Recovery	4,151.7	1,569.1	5,720.8
Technical Revisions	255.9	(4,278.4)	(4,022.5)
Acquisitions	11,894.6	8,056.2	19,950.8
Dispositions	-	-	-
Economic Factors	1,024.5	586.6	1,611.1
Production	(13,221.1)	-	(13,221.1)
December 31, 2007	116,037.5	52,038.4	168,075.9

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 only 50% of our net operating income is available for capital expenditures as the balance is distributed to our Unitholders. As a result, we must develop our assets in an efficient and methodical fashion to reduce risk by technically assessing the results of each of our development programs before committing additional capital. This staged approach to development means that in some 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 5 years and probable undeveloped reserves over the next 8 years. A staged approach to this development refers to our practice of developing reserves through a series of sequential capital investments. These investments are budgeted and incurred annually for a given area. Once the development program is executed, we then measure and analyse the results of that investment program, make any changes that are necessary, and then repeat the process until all economic oil and gas reserves are developed. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

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

Year	**Light and Medium Oil (Mbbl)**		**Heavy Oil (Mbbl)**		**Natural Gas (MMcf)**		**NGLs (Mbbl)**	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	1,768.9	1,768.9	19,898.0	19,898.0	7,800.0	7,800.0	384.6	384.6
2005	197.7	1,660.2	9,077.7	28,722.0	11,317.9	19,026.8	424.0	615.1
2006	-	1,492.7	7,569.9	30,085.7	951.2	17,466.0	24.3	629.9
2007	2,112.0	3,574.1	9,833.3	38,168.8	2,559.3	15,587.0	55.6	378.4

Sproule assigned a total of 471 wells to the proved undeveloped reserve category. Approximately 2/3 of these or a total of 304 proved undeveloped locations, are located in the, Carruthers, Celtic and Tangleflags heavy oil properties in Saskatchewan, as well as the Seal, Ardmore and Cold Lake heavy oil properties in Alberta. These heavy oil locations are scheduled to be developed over the next six years. A further total of 35 proved undeveloped locations are located in the Stoddart, British Columbia and Pembina, Red Earth and Knobhill, Alberta light oil and gas properties. These conventional oil and gas locations are scheduled to be developed over the next five 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 annual operating budget mandates that we use only 30 to 50% of our available cash flow for development activities. This restricts the number of development wells we will drill in any given year to approximately 110 based on 2007 spending and activity levels. Not all of the development wells that we drill are contained within the Sproule proved undeveloped inventory. At our current pace of investment and drilling it will take five to six years to develop all the currently identified proved undeveloped reserves.

Probable Undeveloped Reserves

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

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)	
	First Attributed	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
Prior	673.3	673.3	11,351.5	11,351.5	5,303.9	5,303.9	61.8	61.8
2005	19.6	523.7	3,209.0	13,621.9	8,555.0	12,774.2	608.0	608.0
2006	2.0	524.6	4,556.5	17,591.8	291.1	8,541.0	1.4	302.6
2007	1,040.8	1,557.5	3,804.1	20,410.1	5,476.3	10,832.0	513.3	615.7

Sproule assigned a total of 189 wells to the probable undeveloped reserve category. Approximately 50% of these or a total of 94 probable undeveloped locations, are located in the, Carruthers, Celtic and Tangleflags heavy oil properties in Saskatchewan, as well as the Seal, Ardmore and Cold Lake heavy oil properties in Alberta. These heavy oil locations are scheduled to be developed over the next nine years. A further total of five probable undeveloped locations are located in the Stoddart, British Columbia and Pembina, Red Earth and Knobhill, Alberta light oil and gas properties. These conventional oil and gas locations are scheduled to be developed over the next seven years.

For the same reasons as described above, we will not develop all of our probable undeveloped reserves over the next two years. Our annual operating budget mandates that we use only 30 to 50% of our available cash flow for development activities. This restricts the number of development wells we will drill in any given year to approximately 110 based on 2007 spending and activity levels. Very few of the development wells that we drill are contained within the Sproule probable undeveloped inventory as these locations are by definition technically riskier than proved undeveloped locations. At our current pace of investment and drilling it will take seven to nine 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 Carruthers, Celtic and Tangleflags heavy oil properties in Saskatchewan, our Seal, Ardmore and Cold Lake heavy oil properties in Alberta and to our Stoddart, British Columbia and Pembina, Red Earth and Knobhill, Alberta light oil and gas properties. As well, we have a significant amount of probable nonproducing and probable undeveloped reserves assigned to these same properties. At the current prices, these development activities are economic. However, should oil and natural gas prices fall materially, these activities may not be economic and we could defer their implementation. In addition, reserves can be affected significantly by fluctuations in capital expenditures, operating costs, royalty regimes, and well performance that are beyond our control and which could impact our development decisions. See also "*Risk Factors*".

Future Development Costs

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

	FORECAST PRICES AND COSTS	
Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2008	86,940	101,704
2009	101,287	101,659
2010	90,359	102,199
2011	52,103	52,212
2012	39,077	40,214
Remaining	57,366	137,326
Total (Undiscounted)	427,132	535,314

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and equity financings. We withhold approximately 40% to 50% of our cash flow to assist in funding 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.

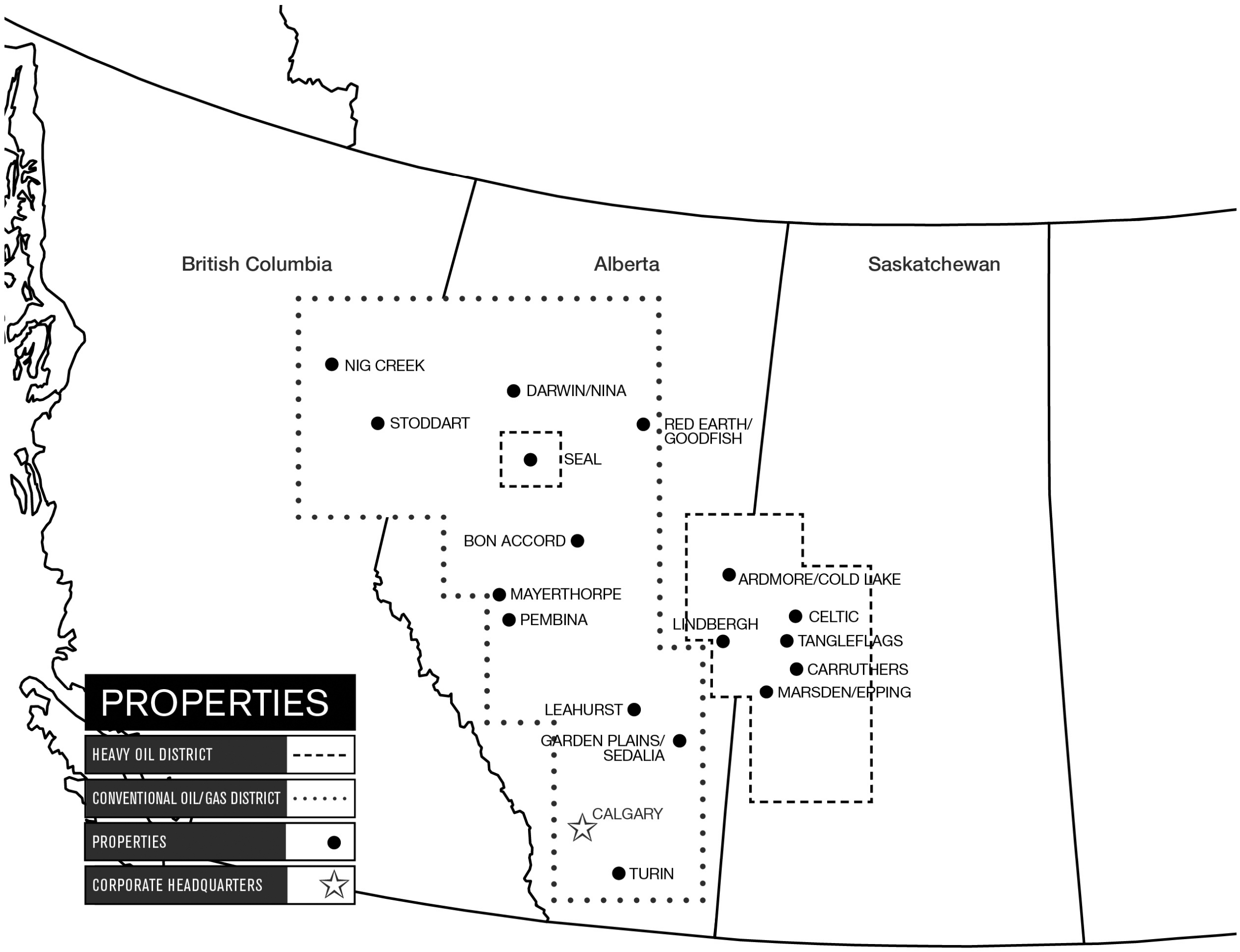
The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth herein and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would 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, 2007. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2007. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2007, except where otherwise indicated.

Baytex's crude oil and natural gas operations are organized into two operating districts: the Heavy Oil District and the Conventional Oil and Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these districts, 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.



Heavy Oil District

The Heavy Oil District accounts for more than 55% of current production, more than 70% of oil-equivalent reserves and over half of Baytex's cash flow from operations. 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 containing lower-than-average viscosity crudes 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 100 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 a light-hydrocarbon diluent (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 diluent.

In 2007, production in the Heavy Oil District averaged approximately 22,100 bbl/d of heavy oil and 734 Mcf/d of natural gas (23,400 Boe/d). Baytex drilled 94 gross (93.5 net) wells in the Heavy Oil District resulting in 87 (86.5 net) oil wells, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96.8% (96.8% net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River areas. 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 Baytex's large inventory of heavy oil investment projects, we are able to select between a wide range of investments 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 area of historical emphasis around Lloydminster in southwest Saskatchewan and southeast Alberta. Our net undeveloped lands in the Heavy Oil District totalled approximately 295,000 acres at year-end 2007.

<u>Ardmore, Alberta</u>: Acquired in 2002 at a production rate of 2,200 bbl/d, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2007 was approximately 1,900 bbl/d of oil and 480 Mcf/d of natural gas (2,000 boe/d). Three successful oil wells and no dry holes were drilled in the area during 2007. Baytex anticipates drilling three wells in this area in 2008. In addition, new production techniques, such as cold horizontal well production and cyclic steam injection are being evaluated for the large hydrocarbon resource in this area. Due to extensive Baytex infrastructure in this area, operating expenses in 2007 remained relatively low at approximately $8.20 per boe. Net undeveloped lands were 39,000 acres at year-end 2007.

<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. During 2007, average production was approximately 2,300 bbl/d of heavy oil and 780 Mcf/d of natural gas (2,400 boe/d). No new wells were drilled in this area in 2007 but the hot waterflood project was expanded by flowlining to eight existing wells and, converting five wells to injection. Net undeveloped lands were 9,900 acres at year-end 2007.

<u>Celtic, Saskatchewan</u>: This producing property was acquired in October 2005, in a transaction which included approximately 2,000 bbl/d of Steam Assisted Gravity Drainage (SAGD) production. The SAGD production was divested at the end of 2005, leaving Baytex with 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, cold production increased to an average of 4,500 bbl/d of heavy oil and 1330 Mcf/d of natural gas (4,700 boe/d) during 2007. (This production number includes 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 within multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Also like Tangleflags, 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 2008 Baytex expects to drill 25 new wells and re-complete up to 70 existing wells. Net undeveloped lands were 8,300 acres at year-end 2007.

<u>Cold Lake, Alberta</u>: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2007 was approximately 600 bbl/d, during which time Baytex drilled two oil wells. Two new wells are planned for 2008. Net undeveloped lands were 13,600 acres at year-end 2007.

<u>Marsden/Epping/Macklin/Silverdale, Saskatchewan</u>: 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 2007 was approximately 2,400 bbl/d of oil and 110 Mcf/d of natural gas (2,500 boe/d). Nine oil wells and one dry hole were drilled in this region in 2007. For 2008, 26 new wells are planned for this area including a 16 well development program to expand the Silverdale Sparky oil pool. A significant facility expansion involving emulsion flow-lining and conservation of the solution gas is also planned for this pool. Net undeveloped lands were 24,300 acres at year-end 2007.

<u>Seal, Alberta</u>: Seal is a highly prospective property located in the Peace River oil sands area of northern Alberta. Baytex holds a 100% working interest in over 100 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced through primary methods using horizontal wells at initial rates of approximately

150 bbl/d per well without employing more capital-intensive methods such as steam injection. During 2007, Baytex drilled four new stratigraphic test wells to identify extensions to our current development area located on the western block of these land holdings. Baytex also drilled 17 new horizontal producing wells in 2007, bringing the total number of producing wells to 25. The average production rate during 2007 was 1,600 bbl/d of heavy oil. Baytex plans to drill four additional stratigraphic test wells and 15 to 20 horizontal producing wells at Seal during 2008. Detailed reservoir simulations of the Seal property have indicated that both waterflood and cyclic steam recovery methods have the potential to greatly increase the ultimate recovery factor beyond what is achievable with primary recovery. A horizontal well drilled in 2007 was equipped for steam injection. Following six months of primary production, this thermal test well will undergo an initial cycle of steam injection commencing in the first half of 2008. In order to reduce operating expenses Baytex will also expand the area facilities in the first quarter of 2008 by constructing a water disposal plant and fuel gas supply pipeline. As the region continues to develop, the Seal property is expected to take an increasingly more prominent role in our production profile. Net undeveloped lands in this area were 56,000 acres at year-end 2007.

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 uphole re-completion opportunities. In 2007, 16 wells were either re-started or re-completed. Average production during 2007 was approximately 1,800 bbl/d of heavy oil and 950 Mcf/d of natural gas (2,000 boe/d). In 2008, Baytex plans to drill two new wells and re-work about 20 existing wells in this area. Net undeveloped lands were 8,900 acres at year-end 2007.

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 21.15% working interest that yields working interest production of approximately 900 bbl/d of heavy oil. Like Tangleflags and Celtic, Lindbergh is as 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 intervals. Baytex expects the field operator to maintain a level of activity that would result in relatively flat production rates. Net undeveloped lands were 11,000 acres at year end 2007.

Conventional Oil and Gas District

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties that generate nearly half of our cash flow. 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 District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. During 2007, production from this district averaged 44,500 Mcf/d of natural gas sales and 5,500 bbl/d of light oil and NGL for annual average oil equivalent production of 12,900 boe/d. During 2007, the District drilled 39 gross (34.0 net) wells resulting in 22 gross (17.5 net) gas wells, 10 gross (9.7 net) oil wells, three gross (2.8 net) service wells and four gross (4.0 net) dry wells for a success rate of 90.0% (88.2% net). Our net undeveloped lands in this district were approximately 344,000 acres at year-end 2007.

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is obtained from the Belly River, Viking and Mannville formations. During 2007, production for the area averaged approximately 3,140 Mcf/d of gas and 300 bbl/d of light oil (800 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. During 2007, Baytex drilled three gross (2.75 net) oil wells in this area. At year-end 2007, Baytex had 15,000 net undeveloped acres in this area.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Baytex-operated gas plants. Production during 2007 averaged approximately 2,900 Mcf/d (500 boe/d). During 2007, Baytex installed an amine facility at Darwin to remove carbon dioxide from the sales gas and improve operating capability and product netback for the area. At year-end 2007, Baytex had 41,000 net undeveloped acres in this area.

Leahurst, Alberta: Production averaged approximately 3,900 Mcf/d (700 boe/d) sales gas during 2007 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 2007, Baytex participated in the drilling of 10 operated and three non-operated locations, resulting in 13 gross (9.8 net) producing gas wells. During 2008, Baytex plans to drill up to five wells in this area. At year-end 2007, Baytex had 14,900 net undeveloped acres in this area.

Pembina, Alberta: Baytex acquired its position in this area in June 2007. Production is primarily obtained from the Nisku formation and to a lesser extent from the Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg formations. 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 for further processing to a combination of four mid-stream gas processing facilities in the area. From July to December 2007, production averaged approximately 3,900 bbl/d of light oil and NGL and 7,800 Mcf/d of gas (5,200 boe/d).During 2007, Baytex drilled two Nisku tests that, while unsuccessful in the targeted formation, were cased as potential water source wells to support future water injection requirements. Baytex plans to drill four gross wells in this area during 2008.At year-end 2007, Baytex had 11,200 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. During 2007, production averaged approximately 7,300 Mcf/d of gas (1,200 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas production from this area is processed at two Baytex-operated gas plants. During 2007, Baytex drilled three gas wells in this area. At year-end 2007, Baytex had 36,100 net undeveloped acres in this area.

Red Earth/Goodfish, 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 2007 averaged approximately 4,330 Mcf/d and 600 bbl/d of light oil and NGL (1,300 boe/d). During 2007, Baytex drilled one oil well in this area. At year-end 2007, Baytex had 33,700 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition was completed in December 2004. Oil and liquids rich gas production from 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 2007 averaged approximately 11,200 Mcf/d of gas and 1,800 bbl/d of oil and NGL (3,700 boe/d). Baytex drilled 11 gross (10.2 net) wells in 2007 resulting in seven gross (6.2 net) oil wells and four dry holes. During 2008, Baytex plans to drill up to six wells and re-complete several wells in the area. At year-end 2007, Baytex had 33,300 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004 with the acquisition of a private company. Production during 2007 averaged approximately 600 bbl/d of oil and NGL and 1,990 Mcf/d of gas (900 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 2007, Baytex drilled one gas well and one oil well in this area. At year-end 2007, Baytex had 11,800 net undeveloped acres in this area.

United States

Baytex opened an office in Denver, Colorado during 2007 with the mandate of acquiring and developing oil and gas assets in the United States. Baytex's objectives in making U.S. investments are to increase geographical, product mix and currency diversification; to expose Baytex to a larger set of investment opportunities; to enhance long-term growth; and to better match Baytex's asset base to its investor base. At present, Baytex has conducted land acquisition activities in Wyoming and Utah, with first drilling expected in the second quarter of 2008. We currently have no oil or gas production in the United States.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2007.

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Gas (Mcf/d)
Heavy Oil District			
Ardmore	-	1,930	483
Carruthers	-	2,265	779
Celtic	-	4,510	1,326
Cold Lake	-	610	-
Golden lake	-	551	-
Greenstreet	-	-	1,120
Hoosier	-	545	
Lashburn	-	76	48
Lindbergh	-	483	37
Maidstone	-	844	-
Marsden	-	1,025	-
Neilburg	-	613	-
Poundmaker	-	1,366	702
Seal	-	1,600	-
Silverdale / Epping / Macklin	-	1,398	113
Sugden	-	768	-
Tangleflags	-	1,767	947
Remaining properties	-	1,741	1,785
Conventional Oil and Gas District			
Bon Accord	286	-	3,141
Darwin/Nina	-	-	2,895
Goodfish	-	-	4,301
Hamburg/Chinchaga	36	-	2,336
Leahurst	10	-	3,904
Pembina	1,974	-	4,087
Red Earth	612	-	28
Richdale / Sedalia	16	-	7,313
Stoddart	1,775	-	11,203
Tangent	-	-	274
Turin	624	-	1,988
Viking	-	-	1,290
Remaining Properties	150	-	1,754
Total	5,483	22,092	51,854

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2007:

	Costs Incurred $ Million
Property acquisition costs:	
Proved properties (1)	245
Unproved properties	7
Development Costs (2)	130
Exploration Costs (3)	12
Total	394

Notes:
(1) Acquisitions are net of disposition of properties.
(2) Development and facilities expenditures.
(3) Cost of geological and geophysical capital expenditures and drilling costs for 2007 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, 2007.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	779	458.4	708	357.1	521	404.8	311	240.2
British Columbia	59	58.2	25	23.8	35	31.8	12	9.0
Saskatchewan	1,204	1109.7	623	598.6	54	50.3	47	44.3
Total	2,042	1,626.3	1,356	979.5	610	486.9	370	293.5

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2007.

	Undeveloped Acres	
	Gross	Net
Alberta	623,063	458,635
British Columbia	86,903	63,182
Saskatchewan	132,360	117,158
Utah	3,035	1,518
Wyoming	15,439	8,723
Total	860,800	649,216

We expect that rights to explore, develop and exploit approximately 118,563 net acres of our undeveloped land holdings may expire on or before December 31, 2008. There are no material drilling commitments associated with the land holdings expiring by December 31, 2008.

Exploration and Development Activities

Up to 10% of our annual exploration and development budget may be spent on exploration activities.

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2007.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	11	11.0	92	87.3
Natural Gas	-	-	20	16.8
Evaluation	4	4.0	-	-
Service	2	1.8	1	1
Dry	1	1.0	5	5.0
Total	18	17.8	118	109.1

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2007, see Notes 17 and 18 to our Consolidated Financial Statements on pages 49 to 51 of our 2007 Annual Report, which are incorporated herein by reference.

Tax Horizon

We are a taxable entity under the *Income Tax Act* (Canada) 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 *Income Tax Act* (Canada) 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. Based on proposed changes announced by the federal government this may change. 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 Proposal. See "*Baytex Energy Trust – Federal Tax Changes for Income Trusts and Corporations*".

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 factor" (effectively, the federal general corporate tax rate plus 13 percent on account of provincial corporate tax or 10 percent based on the recently announced Provincial SIFT Tax Proposal) 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. For more information, see "*Risk Factors – We may be impacted by recent Federal Tax Changes for Income Trusts and Corporations*" and "*Risk Factors – 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 ($MM)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($MM)
Total liability as at December 31, 2007	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, 2007. 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, 2007.

Expenditure	**($000s)**
Land	7,253
Seismic	1,994
Drilling and completion	108,106
Equipment	26,624
Other	4,742
Total exploration and development	148,719
Corporate acquisitions	243,273
Property acquisitions	2,877
Property dispositions	(723)
Net capital expenditures	394,196

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2008, 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 (MMcf/d)**	**Natural Gas Liquids (bbl/d)**	**BOE (boe/d)**
Total Proved	4,248.5	24,096.5	51.3086	2,109.0	39,005.4
Total Proved plus Probable	4,756.3	25,802.5	55.8204	2,400.0	42,262.2

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 2007				**Year Ended**
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**	**Dec. 31, 2007**
Average Daily Production [(1)]					
Light Oil and NGL (bbl/d) [(2)]	8,123	6,556	3,705	3,484	5,483
Natural Gas (Mcf/d)	53.9	53.7	49.3	50.6	51.9
Heavy Oil (bbl/d)	22,196	22,593	21,444	22,129	22,092
Total (boe/d)	39,304	38,094	33,372	34,041	36,222
Average Net Production Prices Received					
Light Oil and NGL($/bbl) [(2)]	74.77	67.82	54.42	51.08	65.53
Natural Gas ($/Mcf)	6.31	5.80	7.02	7.43	6.61
Heavy Oil ($/bbl)	50.13	45.89	40.14	40.17	44.28
Total ($/boe)	52.32	47.06	42.22	42.38	46.38

	Quarter Ended 2007				Year Ended
	Dec. 31	Sept. 30	June 30	Mar. 31	Dec. 31, 2007
Royalties Paid					
Light Oil and NGL($/bbl) [(2)]	15.89	15.82	8.41	5.54	12.99
Natural Gas ($/Mcf)	1.11	0.90	1.40	1.30	1.17
Heavy Oil ($/bbl)	6.88	7.11	6.29	6.36	6.68
Total ($/boe)	8.62	8.22	7.04	6.64	7.70
Production Costs [(3)(4)]					
Light Oil and NGL($/bbl) [(2)]	9.46	12.17	10.45	11.67	10.79
Natural Gas ($/Mcf)	1.64	1.43	1.49	1.33	1.48
Heavy Oil ($/bbl)	10.66	11.36	10.33	9.18	10.40
Total ($/boe)	10.25	10.84	10.00	9.14	10.09
Transportation					
Light Oil and NGL($/bbl) [(2)]	0.50	0.44	1.02	1.11	0.66
Natural Gas ($/Mcf)	0.14	0.14	0.18	0.13	0.15
Heavy Oil ($/bbl)	2.92	2.68	3.52	2.97	3.01
Total ($/boe)	1.98	1.86	2.64	2.24	2.16
Netback Received [(5)]					
Light Oil and NGL($/bbl) [(2)]	48.92	39.39	34.54	32.76	41.09
Natural Gas ($/Mcf)	3.42	3.33	3.95	4.67	3.81
Heavy Oil ($/bbl)	29.67	24.74	20.00	21.66	24.19
Total ($/boe)	31.47	26.14	22.54	24.36	26.43

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 percent 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 2008, Baytex has entered into several physical forward sales contracts.

Oil and NGL

Benchmark WTI prices began 2007 around US$61 per barrel, climbed to an all-time high of US$100 per barrel in December, and ended the year just under US$96.00 per barrel. The average WTI price for 2007 was US$72.31 per barrel, an increase of nine percent from US$66.22 in 2006.

Baytex's light oil and natural gas liquids prices averaged $65.53 per barrel in 2007, an increase of 22% over the $53.84 average in 2006. Our heavy oil prices averaged $44.28 per barrel in 2007, compared to $43.57 in 2006.

For 2008, Baytex has entered into a series of 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 2008 on 6,000 bbl/d, at a weighted average price from US$63.33 to US$ 79.13 per barrel. In addition, Baytex has entered into a series of physical supply contracts requiring delivery of blended volumes for sales at a fixed pricing differential to WTI. For 2008, 15,340 bbl/d of blended volumes have been sold at approximately 67% of WTI. For 2009, 10,340 bbl/d have been sold at approximately 67% 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*" below) and to one vote at all meetings of Unitholders for each Trust Unit held.

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 price per Trust Unit is a function of our anticipated distributable income and the ability of the Board of Directors to effect long term growth in our value. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates, commodity prices and our ability to acquire additional assets. 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 distributions of our available cash 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 enables 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.

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.

Under the terms of the Voting and Exchange Trust Agreement, we have issued one Special Voting Right to Valiant Trust Company for the benefit of every person who received Exchangeable Shares pursuant to the plan of arrangement which was completed on September 2, 2003. For a description of the Exchangeable Shares, see "*Baytex Share Capital –Exchangeable Shares*" below.

Convertible Debentures

On June 6, 2005, we issued $100 million principal amount of 6.5% convertible unsecured subordinated 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 has been filed on SEDAR at *www.sedar.com*.

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 early 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 such indenture, reference should be made to the Trust Indenture, a copy of which has been filed on SEDAR at *www.sedar.com*.

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 cost, 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 as to avoid as much as possible any material risk of liability to Unitholders for claims against us. These activities include by 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. The current distribution policy targets the use of approximately 40 percent to 50 percent of cash available for distribution for capital expenditures. Depending upon commodity prices, 40 percent to 50 percent of the cash available for distribution 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 its 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.

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 if 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.

The following is a summary of the distributions paid or declared by us from inception in September of 2003 to March 17, 2008.

For the Month Ended	Distribution	Payment Date
September to December 2003	$0.15 per Unit	15th of the following month
January to December 2004	$0.15 per Unit	15th of the following month
January to December 2005	$0.15 per Unit	15th of the following month
January to December 2006	$0.18 per Unit	15th of the following month
January 31, 2007	$0.18 per Unit	February 15, 2007
February 28, 2007	$0.18 per Unit	March 15, 2007
March 31, 2007	$0.18 per Unit	April 17, 2007
April 30, 2007	$0.18 per Unit	May 15, 2007
May 31, 2007	$0.18per Unit	June 15, 2007
June 30, 2007	$0.18 per Unit	July 16, 2007
July 31, 2007	$0.18 per Unit	August 15, 2007
August 31, 2007	$0.18 per Unit	September 17, 2007
September 30, 2007	$0.18 per Unit	October 16, 2007
October 31, 2007	$0.18 per Unit	November 15, 2007
November 30, 2007	$0.18 per Unit	December 17, 2007
December 31, 2007	$0.18 per Unit	January 15, 2008
January 31, 2008	$0.18 per Unit	February 15, 2008
February 29, 2008	$0.18 per Unit	March 17, 2008

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 Baytex considers, in its sole discretion, provides 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 a 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 registered retirement savings plans, registered retirement income funds, deferred profit sharing plans and registered education savings plans.

Non-resident Unitholders

It is in the best interest of Unitholders that we qualify as a "unit trust" and a "mutual fund trust" under the *Income Tax Act* (Canada). Certain provisions of the *Income Tax Act* (Canada) require that we not be established nor maintained primarily for the benefit of non-residents of Canada. Accordingly, in order to comply with such provisions, the Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are non-residents. In this regard, we are required, among other things, to take all necessary steps to monitor the ownership of the Trust Units to carry out such intentions. If at any time we become aware that the beneficial owners of 49 percent or more of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, we will take such action as may be necessary to carry out the intentions evidenced therein. As at February 29, 2008, approximately 45 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.

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.

Takeover Bids

The Trust Indenture contains provisions to the effect that if a takeover 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 takeover 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 takeover bid on the terms offered by the offeror.

The Trustee

Valiant Trust Company is our trustee. 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 initial term of the Trustee's appointment is until the third annual meeting of Unitholders. The Unitholders will, at the third annual meeting of Unitholders, re-appoint, or appoint a successor to the Trustee for an additional three year term, and thereafter, Unitholders will reappoint or appoint a successor to the Trustee at the annual meeting of Unitholders three years following the reappointment or appointment of the successor to the Trustee. The Trustee may also 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 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 redemption of Trust Units; (vii) all matters relating to the voting rights on any investments in our assets or any subsequent investments; (viii) 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 be 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 adviser 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, adviser 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, adviser 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 *Income Tax Act* (Canada) as from time to time amended or replaced;

(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 name, municipality of residence, principal occupation for the prior five years of each of the directors and officers of Baytex are as follows:

Name and Municipality Of Residence	Position with Baytex	Principal Occupation
John A. Brussa (2) (3) (4) (6) Calgary, Alberta	Director	Partner, Burnet, Duckworth & Palmer LLP (a law firm).
Raymond T. Chan Calgary, Alberta	Chief Executive Officer and Director	Chief Executive Officer of Baytex since November 2007; prior thereto President and Chief Executive Officer of Baytex since September 2003; prior thereto, Senior Vice President and Chief Financial Officer of Baytex since 1998.
Edward Chwyl (2) (3) (4) Victoria, B.C.	Chairman of the Board of Directors	Independent businessman since May 2002; prior thereto Chairman of the Board of Ventus Energy Ltd. (a public oil and gas company).
Naveen Dargan (1) (2) (4) Calgary, Alberta	Director	Independent businessman since June 2003; prior thereto Senior Managing Director of Raymond James Ltd. (an investment banking firm).
R.E.T. (Rusty) Goepel (1) Vancouver, B.C.	Director	Senior Vice President of Raymond James Ltd.
Dale O. Shwed (1) (3) (7) Calgary, Alberta	Director	President and Chief Executive Officer of Crew Energy Inc. (a public oil and gas company) since September 2003; prior thereto President and Chief Executive Officer of Baytex since 1993.

Name and Municipality Of Residence	Position with Baytex	Principal Occupation
W. Derek Aylesworth Calgary, Alberta	Chief Financial Officer	Chief Financial Officer of Baytex since November 2005; prior thereto Commercial Manager, Ecuador Region, EnCana Corporation (a public oil and gas company) from 2003; prior thereto, Division Vice President, International New Ventures Exploration, EnCana Corporation since 2001.
Randal J. Best Calgary, Alberta	Senior Vice President, Corporate Development	Senior Vice President, Corporate Development of Baytex since December 2006; prior thereto Vice President, Corporate Development of Baytex since September 2003; prior thereto Managing Director of Waterous Securities since 2000.
Stephen Brownridge Calgary, Alberta	Vice President, Heavy Oil	Vice President, Heavy Oil of Baytex since December 2006; prior thereto Manager, Heavy Oil since September 2003; prior thereto various positions within Baytex since 1997.
Anthony W. Marino Calgary, Alberta	President and Chief Operating Officer	President and Chief Operating Officer of Baytex since November 2007. Prior thereto Chief Operating Officer of Baytex since November 2004; prior thereto President and Chief Executive Officer of Dominion Exploration Canada Ltd. since October 2002 (a wholly owned subsidiary of Dominion Resources Inc., a publicly traded U.S. energy company).
Brett J. McDonald Calgary, Alberta	Vice President, Land	Vice President, Land of Baytex since December 2006; prior thereto General Manager of Land of Baytex since September 2003; prior thereto Senior Landman with Baytex since 2000.
Timothy R. Morris Denver, Colorado	Vice President, US Business Development	Vice President, US Business Development of Baytex since November 2007; prior thereto Managing Director, US Business Development since April 2007; prior thereto Vice President, Land and Administration of Berco Resources, LLC since 2000.
R. Shaun Paterson Calgary, Alberta	Vice President, Marketing	Vice President, Marketing of Baytex since December 2006; prior thereto Vice President, Domestic Crude Oil Marketing for EnCana Corporation (a public oil & gas company) since 2002.
Mark F. Smith Calgary, Alberta	Vice President, Conventional Oil & Gas	Vice President, Conventional Oil & Gas of Baytex since November 2006; prior thereto Vice President, Development North Business Unit of Burlington Resources Canada since September 2004; prior thereto General Manager Deep Basin Business Unit of Burlington Resources Canada (a public oil & gas company) since 2002.
Shannon M. Gangl Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP (a law firm).

Notes:
(1) Member of our Audit Committee.
(2) Member of our Compensation Committee.

(3) Member of our Reserves Committee.
(4) Member of our 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. (now 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.

As at February 29, 2008, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 882,759 Trust Units, or approximately 1.03 percent of the issued and outstanding Trust Units. In addition, as at February 29, 2008, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 455,129 Exchangeable Shares or approximately 29.1 percent of the issued and outstanding Exchangeable Shares. 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, 2007, Baytex employed 138 head office employees and 39 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 Mr. Naveen Dargan, Mr. R.E.T. (Rusty) Goepel and Mr. Dale O. Shwed, each of whom is independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of Multilateral 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	Master of Business Administration degree and Chartered Business Valuator designation. Independent businessman since June 2003; prior thereto Senior Managing Director of Raymond James Ltd.
R.E.T. (Rusty) Goepel	Yes	Yes	Senior Vice President of Raymond James Ltd.
Dale O. Shwed	Yes	Yes	President and Chief Executive Officer of Crew Energy Inc. (a public oil and gas company) since September 2003; prior thereto President and Chief Executive Officer of Baytex.

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 2007 and 2006:

	Aggregate fees billed ($000s)	
	2007	**2006**
Audit fees	851	549
Tax fees	5	4
All other fees	133	187
	989	740

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 2007 and 2006 also include the reviews of comment letters from Canadian and U.S. regulatory agencies. The 2007 fees include 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 also include 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. During fiscal 2007 and 2006, there were no payments in this category.

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

All Other Fees. During fiscal 2007 and 2006, 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 February 29, 2008, there were 1,563,440 Exchangeable Shares issued and outstanding. We are the sole holder of the issued and outstanding common shares of Baytex.

The following is a summary of certain provisions of the share capital of Baytex and the related and ancillary rights of holders of Exchangeable Share granted under the Voting and Exchange Trust Agreement and the Support Agreement. For a complete description of the share provisions and these related agreements, reference should be made to the Articles of Baytex and these agreements, copies of which been filed on SEDAR at www.sedar.com.

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. At December 31, 2007, 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 granted under the Voting and Exchange Trust Agreement to the Trustee) 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.

Ranking

The Exchangeable Shares rank rateably with shares of any other series of exchangeable shares of Baytex and prior to any common shares and any other shares ranking junior to the Exchangeable Shares with respect to the payment of dividends, if any, that have been declared and the distribution of assets in the event of the liquidation, dissolution or winding-up of Baytex.

Dividends

Holders of Exchangeable Shares are entitled to receive cash dividends if, as and when declared by the Board of Directors. Baytex anticipates that it may from time to time declare dividends on the Exchangeable Shares up to but not exceeding any cash distributions on the Trust Units into which such Exchangeable Shares are exchangeable. In the event that any such dividends are paid, the Exchange Ratio will be correspondingly reduced to reflect such dividends.

Certain Restrictions

Baytex will not, without obtaining the approval of the holders of the Exchangeable Shares as set forth below under the subheading "*Amendment and Approval*":

(a) pay any dividend on the common shares or any other shares ranking junior to the common shares, other than stock dividends payable in common shares or any other shares ranking junior to the Exchangeable Shares;

(b) redeem, purchase or make any capital distribution in respect of the common shares of Baytex or any other shares ranking junior to the Exchangeable Shares;

(c) redeem or purchase any other shares of Baytex ranking equally with the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or

(d) issue any shares, other than Exchangeable Shares or common shares, which rank superior to the Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution.

The above restrictions will not apply if all declared dividends on the outstanding Exchangeable Shares have been paid in full.

Liquidation or Insolvency of Baytex

In the event of the liquidation, dissolution or winding-up of Baytex or any other proposed distribution of the assets of Baytex among its shareholders for the purpose of winding up its affairs, a holder of Exchangeable Shares will be entitled to receive from Baytex, in respect of each such Exchangeable Share, that number of Trust Units equal to the Exchange Ratio as at the effective date of such event.

Upon the occurrence of such an event, we and Baytex ExchangeCo each have the overriding right to purchase all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by us or any of our subsidiaries) at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio at such time and, upon the exercise of this right, the holders will be obligated to sell such Exchangeable Shares to us or Baytex ExchangeCo, as applicable.

Automatic Exchange Right on Liquidation of the Trust

The Voting and Exchange Trust Agreement provides that in the event of a "**Trust liquidation event**", as described below, we or Baytex ExchangeCo will be deemed to have purchased all outstanding Exchangeable Shares and each holder of Exchangeable Shares will be deemed to have sold their Exchangeable Shares immediately prior to the Trust liquidation event at a purchase price per Exchangeable Share to be satisfied by the issuance or delivery, as the case may be, of that number of Trust Units equal to the Exchange Ratio of the Exchangeable Shares at that time. For this purpose, a "Trust liquidation event" means:

- any determination by us to institute voluntary liquidation, dissolution or winding-up proceedings or to effect any other distribution of our assets among Unitholders for the purpose of winding up our affairs; or

- the earlier of, us receiving notice of and us otherwise becoming aware of, any threatened or instituted claim, suit, petition or other proceedings with respect to the involuntary liquidation, dissolution or winding up of us or to effect any other distribution of our assets among Unitholders for the purpose of winding up our affairs in each case where we have failed to contest in good faith such proceeding within 30 days of becoming aware thereof.

Retraction of Exchangeable Shares by Holders and Retraction Call Right

Subject to the retraction call right of the Trust and Baytex ExchangeCo described below, a holder of Exchangeable Shares will be entitled at any time to require Baytex to redeem any or all of the Exchangeable Shares held by such holder for a retraction price per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the retraction date, to be satisfied by the delivery of such Trust Units.

Holders of the Exchangeable Shares may request redemption by presenting to Baytex or the transfer agent for the Exchangeable Shares a certificate or certificates representing the number of Exchangeable Shares the holder desires to have redeemed, together with a duly executed retraction request and such other documents as may be reasonably required to effect the redemption of the Exchangeable Shares. The redemption will become effective on the retraction date, which will be three business days after the date on which Baytex or the transfer agent receives the retraction notice.

When a holder requests Baytex to redeem the Exchangeable Shares, we and Baytex ExchangeCo will have a overriding right to purchase on the retraction date all of the Exchangeable Shares that the holder has requested Baytex to redeem at a purchase price per Exchangeable Share equal to the retraction price, to be satisfied by the delivery of that number of Trust Units equal to the Exchange Ratio at such time. At the time of such a request by a holder of Exchangeable Shares, Baytex will immediately notify us and Baytex ExchangeCo. We or Baytex ExchangeCo must then advise Baytex within two business days as to whether our purchase right will be exercised.

A holder may revoke his or her retraction request at any time prior to the close of business on the last business day immediately preceding the retraction date. Otherwise, the Exchangeable Shares that the holder has requested Baytex to redeem will be purchased by the Trust or Baytex ExchangeCo or redeemed by Baytex, as the case may be, in each case at a purchase price per Exchangeable Share equal to the retraction price.

In addition, a holder of Exchangeable Shares may elect to instruct the Trustee to exercise a right ("**Optional Exchange Right**") to require us or Baytex ExchangeCo to acquire such holder's Exchangeable Shares in circumstances where neither we nor Baytex ExchangeCo have exercised the overriding purchase right. See "*Voting and Exchange Trust Agreement – Optional Exchange Right*" below. If, as a result of solvency provisions of applicable law, Baytex is not permitted to redeem all Exchangeable Shares tendered by a retracting holder, Baytex will redeem only those Exchangeable Shares tendered by the holder as would not be contrary to such provisions of applicable law. The holder of any Exchangeable Shares not redeemed by Baytex will be deemed to have required us to purchase such unretracted Exchangeable Shares in exchange for Trust Units on the retraction date pursuant to the Optional Exchange Right. See "*Voting and Exchange Trust Agreement – Optional Exchange Right*" below.

Redemption of Exchangeable Shares

Subject to applicable law and the call rights of the Trust and Baytex ExchangeCo, Baytex:

(a) will, on September 2, 2013, subject to extension of such date by the Board of Directors, redeem all but not less than all of the then outstanding Exchangeable Shares for a redemption price per Exchangeable Share equal to the value of that number of Trust Units equal to the Exchange Ratio as at the last business day prior to that redemption date (the "**redemption price**"), to be satisfied by the delivery of such number of Trust Units;

(b) may, on any date that is within the first 90 days of any calendar year, redeem up that number of Exchangeable Shares equal to 40 percent of the Exchangeable Shares which were outstanding on September 2, 2003 for the redemption price per Exchangeable Share at the last business day prior to that redemption date, to be satisfied by the delivery of Trust Units; and

(c) may, at any time when the aggregate number of issued and outstanding Exchangeable Shares is less than 1 million (other than Exchangeable Shares held by us and our subsidiaries and as such shares may be adjusted from time to time), redeem all but not less than all of the then outstanding Exchangeable Shares for the redemption price per Exchangeable Share (unless contested in good faith by the Trust).

Baytex will, at least 90 days prior to any redemption date, provide the registered holders of the Exchangeable Shares with written notice of the prospective redemption of the Exchangeable Shares by Baytex.

The Trust and Baytex ExchangeCo have the right, notwithstanding a proposed redemption of the Exchangeable Shares by Baytex on the applicable redemption date, to purchase on any redemption date all but not less than all of the Exchangeable Shares then outstanding (other than Exchangeable Shares held by us and our subsidiaries) in exchange for the redemption price per Exchangeable Share and, upon the exercise of this right, the holders of all of the then outstanding Exchangeable Shares will be obliged to sell all such shares to us Baytex ExchangeCo, as applicable.

Voting Rights

Except as required by applicable law, the holders of the Exchangeable Shares are not entitled as such to receive notice of or attend any meeting of the shareholders of Baytex or to vote at any such meeting. Holders of Exchangeable Shares have the notice and voting rights respecting our meetings that are provided in the Voting and Exchange Trust Agreement. See "*Voting and Exchange Trust Agreement – Voting Rights*" below.

Amendment and Approval

The rights, privileges, restrictions and conditions attaching to the Exchangeable Shares may be changed only with the approval of the holders thereof. Any such approval or any other approval or consent to be given by the holders of the Exchangeable Shares will be sufficiently given if given in accordance with applicable law and subject to a minimum requirement that such approval or consent be evidenced by a resolution passed by not less than two-thirds of the votes cast thereon (other than shares beneficially owned by us, or any of our subsidiaries and other affiliates) at a meeting of the holders of the Exchangeable Shares duly called and held at which holders of at least 10 percent of the then outstanding Exchangeable Shares are present in person or represented by proxy. In the event that no such quorum is present at such meeting within one-half hour after the time appointed therefor, then the meeting will be adjourned to such place and time (not less than ten days later) as may be determined at the original meeting and the holders of Exchangeable Shares present in person or represented by proxy at the adjourned meeting will constitute a quorum thereat and may transact the business for which the meeting was originally called. At the adjourned meeting, a resolution passed by the affirmative vote of not less than two-thirds of the votes cast thereon (other than shares beneficially owned by us or any of our subsidiaries and other affiliates) will constitute the approval or consent of the holders of the Exchangeable Shares.

Actions by Us Under the Support Agreement and the Voting and Exchange Trust Agreement

Under the Exchangeable Share provisions, Baytex has agreed to take all such actions and do all such things as are necessary or advisable to perform and comply with its obligations under, and to ensure the performance and compliance by us and Baytex ExchangeCo with our respective obligations under, the Support Agreement and the Voting and Exchange Trust Agreement.

Non-Resident and Tax-Exempt Holders

The obligation of us, Baytex or Baytex ExchangeCo to deliver Trust Units to a non-resident holder in respect of the exchange of such holder's Exchangeable Shares may be satisfied by delivering such Trust Units to the transfer agent who will sell such Trust Units on the stock exchange on which they are listed and deliver the proceeds of sale to the non-resident holder.

VOTING AND EXCHANGE TRUST AGREEMENT

The following is a summary of certain provisions of the Voting and Exchange Trust Agreement. For a complete description of the terms of the Voting and Exchange Agreement, reference should be made to this agreement, a copy of which has been filed on SEDAR at *www.sedar.com*.

Voting Rights

In accordance with the Voting and Exchange Trust Agreement, we have issued one (1) Special Voting Right to Valiant Trust Company, the Voting and Exchange Trust Agreement Trustee, for the benefit of the holders (other than us and Baytex ExchangeCo) of the Exchangeable Shares. The Special Voting Right carries a number of votes, exercisable at any meeting at which Unitholders are entitled to vote, equal to one vote for each Exchangeable Share outstanding. With respect to any written consent sought from Unitholders, each vote attached to the Special Voting Right will be exercisable in the same manner as set forth below.

Each holder of an Exchangeable Share on the record date for any meeting at which Unitholders are entitled to vote will be entitled to instruct the Voting and Exchange Trust Agreement Trustee to exercise that number of votes attached to the Special Voting Right which relate to the Exchangeable Shares held by such holder. The Voting and Exchange Trust Agreement Trustee will exercise each vote attached to the Special Voting Right only as directed by the relevant holder and, in the absence of instructions from a holder as to voting, will not exercise such votes.

The trustee appointed under the Voting and Exchange Trust Agreement is required to send to the holders of the Exchangeable Shares a notice of each meeting at which Unitholders are entitled to vote, together with the related meeting materials and a statement as to the manner in which the holder may instruct the Voting and Exchange Trust Agreement Trustee to exercise the votes attaching to the Special Voting Right, at the same time as we send such notice and materials to Unitholders. The Voting and Exchange Trust Agreement Trustee is also required to send to the holders copies of all information statements, interim and annual financial statements, reports and other materials sent by us to Unitholders at the same time as such materials are sent to Unitholders. To the extent such materials are provided to the Voting and Exchange Trust Agreement Trustee by us, the Voting and Exchange Trust Agreement Trustee will also send to the holders all materials sent by third parties to Unitholders, including dissident proxy circulars and tender and exchange offer circulars, as soon as possible after such materials are first sent to Unitholders.

All rights of a holder of Exchangeable Shares to exercise votes attached to the Special Voting Right will cease upon the exchange of all such holder's Exchangeable Shares for Trust Units. With the exception of administrative changes for the purpose of adding covenants for the protection of the holders of the Exchangeable Shares, making necessary amendments or curing ambiguities or clerical errors (in each case provided that the Board of Directors ExchangeCo and Baytex are of the opinion that such amendments are not prejudicial to the interests of the holders of the

Exchangeable Shares), the Voting and Exchange Trust Agreement may not be amended without the approval of the holders of the Exchangeable Shares.

Optional Exchange Right

Upon the occurrence and during the continuance of:

(a) an Insolvency Event (as defined in the Exchangeable Share provisions); or

(b) circumstances in which we or Baytex ExchangeCo may exercise a Call Right (as defined in the Exchangeable Share provisions), but elect not to exercise such Call Right,

a holder of Exchangeable Shares will have the right ("**Optional Exchange Right**") to instruct the Voting and Exchange Trust Agreement Trustee to exercise the Optional Exchange Right with respect to any or all of the Exchangeable Shares held by such holder, thereby requiring us or Baytex ExchangeCo to purchase such Exchangeable Shares from the holder. Immediately upon the occurrence of (i) an Insolvency Event, (ii) any event which will, with the passage of time or the giving of notice, become an Insolvency Event, or (iii) the election by us and Baytex ExchangeCo not to exercise a Call Right which is then exercisable by us and Baytex ExchangeCo, Baytex, the Trust or Baytex ExchangeCo will give notice thereof to the Voting and Exchange Trust Agreement Trustee. As soon as practicable thereafter, the Voting and Exchange Trust Agreement Trustee will then notify each affected holder of Exchangeable Shares (who has not already provided instructions respecting the exercise of the Optional Exchange Right) of such event or potential event and will advise such holder of its rights with respect to the Optional Exchange Right.

The purchase price payable by us or Baytex ExchangeCo for each Exchangeable Share to be purchased under the Optional Exchange Right will be satisfied by the issuance of that number of Trust Units equal to the Exchange Ratio as at the last business day prior to the day of closing of the purchase and sale of such Exchangeable Share under the Exchange Right.

If, as a result of solvency provisions of applicable law, Baytex is unable to redeem all of a holder's Exchangeable Shares which such holder is entitled to have redeemed in accordance with the Exchangeable Share provisions, the holder will be deemed to have exercised the optional exchange right with respect to the unredeemed Exchangeable Shares and we or Baytex ExchangeCo will be required to purchase such shares from the holder in the manner set forth above.

SUPPORT AGREEMENT

The following is a summary of certain provisions of the Support Agreement, a copy of which has been filed on SEDAR at *www.sedar.com*.

Under the Support Agreement, we have agreed that:

(a) we will take all actions and do all things necessary to ensure that Baytex is able to pay to the holders of the Exchangeable Shares the amounts required under the Exchangeable Share provisions in the event of a liquidation, dissolution or winding-up of Baytex, the retraction price in the event of the giving of a retraction request by a holder of Exchangeable Shares or in the event of a redemption of Exchangeable Shares by Baytex; and

(b) we will not vote or otherwise take any action or omit to take any action causing the liquidation, dissolution or winding-up of Baytex.

The Support Agreement also provides that we will not issue or distribute to the holders of all or substantially all of the outstanding Trust Units:

(a) additional Trust Units or securities convertible into Trust Units;

(b) rights, options or warrants for the purchase of Trust Units; or

(c) units or securities of the Trust other than Trust Units, evidences of indebtedness of the Trust or other assets of the Trust;

unless the same or an equivalent distribution is made to holders of Exchangeable Shares, an equivalent change is made to the Exchangeable Shares, such issuance or distribution is made in connection with a distribution reinvestment plan instituted for holders of Trust Units or a unitholder rights protection plan approved for holders of Trust Units by the Board of Directors or the approval of holders of Exchangeable Shares has been obtained.

In addition, we may not subdivide, reduce, consolidate, reclassify or otherwise change the terms of the Trust Units unless an equivalent change is made to the Exchangeable Shares or the approval of the holders of Exchangeable Shares has been obtained.

In the event of any proposed take-over bid, issuer bid or similar transaction affecting the Trust Units, we have agreed to use reasonable efforts to take all actions necessary or desirable to enable holders of Exchangeable Shares to participate in such transaction to the same extent and on an economically equivalent basis as Unitholders.

The Support Agreement also provides that, as long as any outstanding Exchangeable Shares are owned by any person or entity other than us or any of our subsidiaries or affiliates, we will, unless approval to do otherwise is obtained from the holders of Exchangeable Shares, remain the direct or indirect beneficial owner collectively of more than 50 percent of all of the issued and outstanding voting securities of Baytex, provided that we will not be in violation of this obligation if a party acquires all or substantially all of our assets.

With the exception of administrative changes for the purpose of adding covenants for the protection of the holders of the Exchangeable Shares, making certain necessary amendments or curing ambiguities or clerical errors (in each case provided that the Board of Directors and the Trustee are of the opinion that such amendments are not prejudicial to the interests of the holders of the Exchangeable Shares), the Support Agreement may not be amended without the approval of the holders of the Exchangeable Shares.

Under the Support Agreement, we have also agreed to not exercise any voting rights attached to the Exchangeable Shares owned by us or any of our respective subsidiaries and other affiliates on any matter considered at meetings of holders of Exchangeable Shares (including any approval sought from such holders in respect of matters arising under the Support Agreement).

We have also agreed to make such filings and seek such regulatory consents and approvals as are necessary so that the Trust Units issuable upon the exchange of Exchangeable Shares will be issued in compliance with applicable securities laws in Canada and may be traded freely on the Toronto Stock Exchange or such other exchange on which the Trust Units may be listed, quoted or posted for trading from time to time.

MARKET FOR SECURITIES

The Trust Units and the Convertible Debentures are listed and traded on the Toronto Stock Exchange. The trading symbol for the Trust Units is BTE.UN, and for the Convertible Debentures is BTE.DB. The Exchangeable Shares Units are not listed on any stock exchange.

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

	Price Range		
	High ($)	Low ($)	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
2007			
January	22.28	19.29	8,957,643
February	21.38	19.66	6,476,432
March	21.20	18.83	6,416,193
April	21.58	20.15	8,226,464
May	22.92	20.87	5,865,672
June	21.72	20.64	6,562,665
July	21.45	19.58	9,595,310
August	20.60	16.68	9,787,701
September	20.94	17.85	6,982,325
October	20.65	19.20	8,097,604
November	20.60	18.08	5,812,131
December	19.70	18.34	3,515,873
2008			
January	20.08	16.30	8,450,915
February	21.51	17.54	7,664,775

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

	Price Range		
	High ($US)	Low ($US)	Volume Traded
2006	25.87	16.63	21,496,200
2007			
January	18.43	16.32	1,615,800
February	18.48	16.64	1,218,500
March	18.34	16.01	1,346,000
April	19.40	17.42	817,900
May	21.18	18.88	1,191,800
June	20.53	19.24	1,124,900
July	20.46	18.88	1,515,600
August	19.39	15.51	1,695,600
September	21.03	17.35	2,103,700
October	21.43	19.66	2,651,400
November	21.74	18.20	1,698,800
December	19.45	18.19	1,082,500
2008			
January	20.30	15.88	1,550,400
February	22.00	17.37	1,507,100

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

	Price Range		
	High ($)	Low ($)	Volume Traded
2005	127.00	99.50	76,697.5
2006	190.88	114.83	55,005.9
2007			
January	146.00	131.02	451.0
February	140.00	130.02	343.0
March	136.80	127.00	233.0
April	141.30	130.02	210.0
May	150.00	131.31	301.0
June	145.95	140.00	362.0
July	143.29	135.04	159.0
August	130.00	120.00	144.0
September	137.29	126.01	132.0
October	137.96	131.96	113.0
November	134.09	115.00	283.0
December	129.24	124.77	143.5
2008			
January	135.00	121.50	336.0
February	144.22	123.00	210.0

RATINGS

DBRS has assigned a stability rating of STA-6 (high) to us. 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. DBRS has assigned stability ratings to 15 of the largest oil and gas income trusts in Canada, including us, ranging from STA-5 (high) to STA-6 (middle). Specifically, income funds rated as STA-6 are considered by DBRS to have very weak distribution per unit stability and sustainability. An income fund rated as STA-6 is subject to many of the same cyclical, seasonal, commodity price and economic factors as the higher STA-5 rating category, but the lack of diversification is generally more pronounced. In addition such income funds will tend to be "weak" or "moderate" in the majority of the key factors considered when determining a stability rating.

On November 1, 2006 DBRS placed the stability ratings of select Canadian income trusts "Under Review with Developing Implications" following the Federal Minister of Finance's announcement to make significant changes to the way in which Canadian income trusts will be taxed in the future. For income trusts that plan to reduce the level of their distributions to unitholders to reflect the additional tax burden, the reduction would be viewed as a one time event and DBRS's analytical focus would then be on the stability and sustainability of distributions following the adjustments. Under this scenario, the stability ratings would likely be confirmed; however, the proposed legislation could encourage certain trusts to develop alternative capitalisation or operating strategies. Until DBRS is able to discuss these issues with those trusts implementing alternative capitalisation or operating strategies, their ratings would remain under review. Our stability rating would also be subject to this latest "Under Review with Developing Implications" rating adjustment.

On March 8, 2007 DBRS removed us from its "Under Review with Developing Implications" rating, and reconfirmed the stability rating of STA- 6 (high).

Baytex has been assigned a senior implied rating of B1 and an issuer rating of B3, each with a stable outlook by 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.

We have been assigned a long-term corporate credit rating of B+/Stable by 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 "BBB" is regarded as having an adequate capacity to pay interest and repay principal. Whereas it normally exhibits adequate protection parameters, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments 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 and credit ratings accorded to Baytex and us by DBRS, 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 or Exchangeable Shares who beneficially owns or controls or directs, directly of indirectly, more than 10 percent of the outstanding Trust Units or Exchangeable Shares, 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 office in Calgary, Alberta and through its co-agent, BNY Trust Company of Canada, at its principal office in 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 the 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, are partners at Burnet, Duckworth & Palmer LLP, which law firm 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;

(b) the indenture creating the Note and the promissory note evidencing the Notes issued thereunder;

(c) the indenture creating the Convertible Debentures;

(d) our trust unit incentive plan; and

(e) the credit agreement in respect of our $370 million syndicated credit facility, which agreement is described in Note 6 to our consolidated financial statements for the year ended December 31, 2007, which note is incorporated by reference herein.

Copies of each of these documents have been filed on SEDAR 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 agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these 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 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 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 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 lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market 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, 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 negotiations between the mineral 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 few such incentive programs are currently operative.

The Canadian federal corporate income tax rate levied on taxable income is 22.1% effective January 1, 2007 for active business income including resource income. With the elimination of the corporate surtax effective January 1, 2008 and other rate reductions introduced in the October 2007 Economic Statement and Notice of Ways and Means Motion, 2006 Federal Budget, the federal corporate income tax rate will decrease to 15% in five steps: 19.5% on January 1, 2008, 19% on January 1, 2009; 18% on January 1, 2010, 16.5% on January 1, 2011 and 15% on January 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. Currently, the amount of royalties that are payable is influenced by the oil production, density of the oil, and the vintage of the oil. Originally, the vintage classified oil as "new oil" and "old oil" depending on when the oil pools were discovered. If the pool was discovered prior to March 31, 1974 it is considered "old oil", if it was discovered after March 31, 1974 and before September 1, 1992, it is considered "new oil". The Alberta government introduced in 1992 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 has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

The royalty reserved to the Crown in respect of natural gas production, subject to various incentives, is 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. Natural gas produced from qualifying intervals in eligible gas wells spudded or deepened to a depth below 2,500 metres is also subject to a royalty exemption, the amount of which depends on the depth of the well.

Oil sands projects are subject to a specific regulation made effective July 1, 1997, and expiring June 30, 2009, which, among other things, determines the Crown's share of crude and processed oil sands products.

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 ("**ARTC**") was to be eliminated, effective January 1, 2007. The programs affected by this announcement are: (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 being introduced is the Innovative Energy Technologies Program (the "**IETP**") which is intended to promote 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 will be the one to decide which projects qualify and the level of support that will be provided. The deadline for the IETP's third round of applications was May 31, 2007. The successful applicants have not yet been announced and it appears, based on the previous two rounds, that the selection process can take at least 8 months. The technical information gathered from this program is to be made public once a two-year confidentiality period expires.

On October 25, 2007, the Alberta government released a report entitled "The New Royalty Framework" containing the government's proposals for Alberta's new royalty regime is scheduled to be effective on January 1, 2009. The proposed NRF includes new royalty formulas for conventional oil and natural gas that will operate on sliding scales that are determined by commodity prices and well productivity; in addition to the policy of "shallow rights reversion". The Alberta government is intending to implement this policy in order to maximize the development of currently undeveloped resources which is consistent with the government's objective of maximizing recovery of known gas resources, while increasing royalty revenues. The policy's 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. It appears that leaseholders will get a grace period before the shallower zones are reverted to the Crown, which is still to be determined. Substantial legislative, regulatory and systems updates will be introduced before changes become fully effective in January 2009. See "*Risk Factors* ".

British Columbia

Producers of oil and natural gas in the Province of 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 the Province of 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 of up to $30 million annually 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.

- 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.

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", or "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. The royalty/tax will be payable on associated natural gas produced from an oil well that exceeds approximately 65 thousand cubic metres in a month.

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 percent.

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.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the federal government 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 five years since the federal government had the initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income.

In 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 the individual with insufficient financial capability from acquiring oil and gas wells or facilities; and (ii) in the case of a bankrupt company, the funds cover for the decommissioning and reclaiming of orphan property. 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 the Province of 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. 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. Industries can either choose one of these options or a combination thereof. are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment, and will be taking such steps as required to ensure compliance with the EPEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In 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 CO_2 from other emissions supporting carbon capture and storage.

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 the Province's 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 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 gas sector. Among the changes to be implemented are: (i) a new 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, on February 19, 2008 the provincial Government announced that starting on July 1, 2008, provided the legislation is approved; a revenue-neutral carbon tax will be applied to all fossil fuels used in the Province. The tax would be phased in, and the initial rate would be based on CO_{2e} 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 would receive otherwise.

In December, 2002, the Government of Canada ratified the Kyoto Protocol ("**Protocol**"). The 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 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 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 oils 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 facilities; 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 megatonnes 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.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR 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 May 20, 2008 annual and special meeting of Unitholders. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2007 and the related management's discussion and analysis which have been filed on SEDAR at *www.sedar.com*. For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

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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, 2007, 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 Baytex'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 Baytex'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 51-101F2 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) "*Raymond T. Chan*"
Raymond T. Chan
Chief Executive Officer

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

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

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

March 5, 2008

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, 2007. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2007, 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 attributed to proved plus probable reserves, estimated using forecast prices and costs on a before tax basis and calculated using a discount rate of 10 percent, included in the reserves data of the Trust evaluated by us for the year ended December 31, 2007, and identifies the respective portions thereof that we have audited, evaluated 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 – $MM)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Baytex Energy Trust, As of December 31, 2007, prepared October 2007 to February 2008	Canada	Nil	2,494.3	Nil	2,494.3

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 5, 2008

(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" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("MI 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 MI 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.