U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(CHECK ONE)

o **Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934**

or

ý **Annual Report pursuant to Section 13(1) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended: **December 31, 2005**

Commission File Number: **001-32754**

BAYTEX ENERGY TRUST

(Exact name of Registrant as specified in its charter)

Alberta	**1311**	**Not Applicable**
(Province or other jurisdiction of incorporation or organization)	(Primary standard industrial classification code number, if applicable)	(I.R.S. employer identification number, if applicable)

Suite 2200, 205 – 5th Avenue S.W.
Calgary, Alberta
T2P 2V7
(403) 269-4282
(Address and telephone number of registrant's principle executive offices)

CT Corporation System
111 Eighth Avenue
New York, NY 10011
(212) 894-8940
(Name, address (including zip code) and telephone number
(including area code) of agent for service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class:	**Name of each exchange on which registered:**
TRUST UNITS	**New York Stock Exchange**

Securities registered pursuant to Section 12(g) of the Act:
NONE

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
NONE

For annual reports, indicate by check mark the information filed with this form:
ý Annual Information Form ý Audited Annual Financial Statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report.
69,283,369 Trust Units were outstanding as of December 31, 2005.

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the "Exchange Act"). If "Yes" is marked, indicate the file number assigned to the Registrant in connection with such Rule.
Yes o No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.
Yes ý No o

Baytex Energy Trust (the "Registrant") conducts its principal business through an operating subsidiary, Baytex Energy Ltd. (the "Company"). The Registrant is a "voluntary filer" and files annual reports on Form 40-F and amendments to such reports and furnishes current information on Form 6-K to the Securities and Exchange Commission.

Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F:

A. *Annual Information Form*

For the Annual Information Form for the year ended December 31, 2005, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the consolidated audited financial statements for the year ended December 31, 2005, including the report of Independent Registered Chartered Accountants with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F. For a reconciliation of differences between Canadian and United States generally accepted accounting principles, see Note 19 of the Notes to the Consolidated Financial Statements.

C. Management's Discussion and Analysis

For Management's Discussion and Analysis for the year ended December 31, 2005, see Exhibit 99.3 of this annual Report on Form 40-F.

Except where otherwise indicated, all dollar amounts stated in this Annual Report on Form 40-F are in Canadian dollars.

Controls and Procedures

A. Disclosure Controls and Procedures

The Company's Chief Executive Officer and Chief Financial Officer (its principal executive officer and principal financial officer, respectively) have concluded, based on their evaluation as of the end of the period covered by this Annual Report on Form 40-F (the "evaluation date"), that the Registrant's and the Company's disclosure controls and procedures are effective to ensure that information required to be disclosed by it in reports filed or submitted by it under the Securities Exchange Act of 1934, as amended, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission's rules and forms, and includes controls and procedures designed to ensure that information required to be disclosed by it in such reports is accumulated and communicated to the Company's management, including its Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

It should be noted that while the registrant's principal executive officer and principal financial officer believe that the registrant's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the registrant's disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

B. *Changes in Internal Control Over Financial Reporting*

There have been no significant changes to the Company's internal control over financial reporting or in other factors that could significantly affect internal control over financial reporting subsequent to the evaluation date and prior to the filing date of this Annual Report on Form 40-F.

Code of Ethics

The Company's code of ethics, which is applicable to its principal executive officer and senior financial officers, is posted on its website at www.baytex.ab.ca.

The Company has not amended any provision of its Code of Ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or

granted any waiver, including an implicit waiver, from a provision of its Code of Ethics to any of the Company's principal executive officer, principal financial officer, principal accounting officer, or controller or persons performing similar functions that relates to any element of the code of ethics definition as enumerated in paragraph (9)(b) of General Instruction B to Form 40-F in the 2005 fiscal year.

Principal Accountant Fees and Services

The following table provides information about the fees billed to the Registrant and to the Company for professional services rendered by Deloitte & Touche LLP, the Registrant's principal accountant, during fiscal 2005 and 2004:

	Aggregate fees billed by the Principal Accountant	
	2005	2004
	($thousands)	
Audit fees	207	109
Audit-related fees	143	146
Tax fees	42	184

All other fees	44	69
	436	508

Audit Fees. Audit fees consist of fees for the audit of the Registrant's annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements.

Audit-Related Fees. Audit-related services included review of the quarterly financial statements and other financial aspects of the Registrant.

Tax Fees. Tax fees included tax planning and other tax compliance matters.

All Other Fees. Other services provided by the Registrant's principal accountant, other than audit, audit-related and tax services, included advisory services associated with property taxes.

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

The Registrant's Board of Directors has determined that Mr. Naveen Dargan is an audit committee financial expert (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee. Pursuant to paragraph 8(a)(2) of General Instruction B to Form 40-F, the Board has applied the definition of independence applicable to the audit committee members of the New York Stock Exchange ("NYSE") listed companies. Mr. Dargan is a corporate director and meets the NYSE definition of independence. For a description of Mr. Dargan's relevant experience in financial matters, see the five year history in the section "Additional Information Respecting Baytex Energy Ltd. Management of the Trust" in the Registrant's Annual Information Form for the year ended December 31, 2005, which is included as Exhibit 99.1 to this Annual Report on Form 40-F. The registrant's audit committee members consist of Mr. Dargan, Mr. R.E.T. (Rusty) Goepel, and Mr. W.A. Blake Cassidy.

Off-Balance Sheet Arrangements

The Registrant does not have any off-balance sheet arrangements.

Contractual Obligations

Information regarding contractual obligations of the Registrant is included in the Registrant's Management's Discussion and Analysis for the year ended December 31, 2005, which is filed as Exhibit 99.3 to this Annual Report on Form 40-F.

UNDERTAKING

Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities registered pursuant to Form 40-F; the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

CONSENT TO SERVICE OF PROCESS

A Form F-X signed by the Registrant and its agent for service of process was filed with the Commission together with the Registrant's Annual Report on Form 40-F for the fiscal year ended December 31, 2002.

Any change to the name and address of the agent for service for service of process of the Registrant shall be communicated promptly to the Securities and Exchange Commission by an amendment to the Form F-X referencing the file number of the relevant registration statement.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

Registrant: BAYTEX ENERGY TRUST
By: Baytex Energy Ltd.

By: /s/ W. Derek Aylesworth, CA

Name: W. Derek Aylesworth, CA

Title: Chief Financial Officer

Date: March 29, 2006

Form 40-F Table of Contents

Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2005
99.2	Consolidated audited Financial Statements of the Registrant for the year ended December 31, 2005, including reconciliation to United States generally accepted accounting principles, together with the Auditors' Report thereon.
99.3	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2005.
99.4	Certification of Chief Executive Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.5	Certification of Chief Financial Officer under Section 302 of the *Sarbanes-Oxley Act of 2002.*
99.6	Certification of Chief Executive Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.7	Certification of Chief Financial Officer under Section 906 of the *Sarbanes-Oxley Act of 2002.*
99.8	Consent of Deloitte & Touche LLP, independent registered chartered accountants.
99.9	Consent of Sproule Associates Limited, independent engineers.

Exhibit 99.1

BAYTEX ENERGY TRUST

ANNUAL INFORMATION FORM

2005

March 21, 2006

TABLE OF CONTENTS

	Page
SELECTED TERMS	1
ABBREVIATIONS	2
CONVERSIONS	2
CONVENTIONS	3
SPECIAL NOTE REGARDING FORWARD LOOKING STATEMENTS	3
BAYTEX ENERGY TRUST	4
GENERAL DEVELOPMENT OF OUR BUSINESS	6
RISK FACTORS	8
ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY TRUST	40
ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY LTD.	48
AUDIT COMMITTEE	51
BAYTEX SHARE CAPITAL	52
VOTING AND EXCHANGE TRUST AGREEMENT	56
SUPPORT AGREEMENT	57
MARKET FOR SECURITIES	58
RATINGS	59
LEGAL PROCEEDINGS	60
INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS	60
AUDITORS, TRANSFER AGENT AND REGISTRAR	60
INTERESTS OF EXPERTS	60
MATERIAL CONTRACTS	61
INDUSTRY CONDITIONS	61
ADDITIONAL INFORMATION	65

APPENDICES:

APPENDIX A	REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION
APPENDIX B	REPORT ON RESERVES DATA
APPENDIX C	AUDIT COMMITTEE MANDATE

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 February 24, 2006 entitled "Evaluation of the P&NG Reserves of Baytex Energy Trust as of December 31, 2005".

Securities and Other Terms

DRIP Plan means our distribution reinvestment plan.

Convertible Debentures means the 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.

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 the Notes.

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 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	6.289
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 NOTE 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 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. In particular, our drilling plans for the Heavy Oil, Light Oil and Natural Gas District projects are 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;
- the size of the 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;
- 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;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;

- incorrect assessments of the value 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 laws and incentive programs 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.

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.

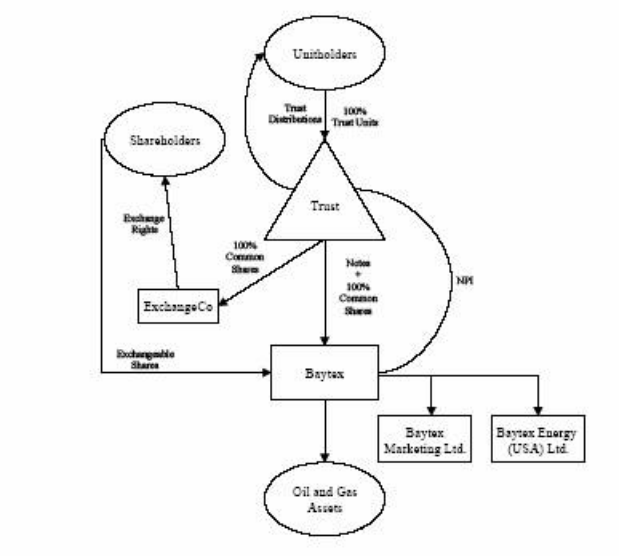
Inter-Corporate Relationships

The following table provides the name, the percentage of voting securities owned by us and the jurisdiction of incorporation, continuance or formation 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 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% of our Trust Units.
(2) Baytex has a total of 1,597,028 Exchangeable Shares issued and outstanding as at December 31, 2005, which were exchangeable into 2,191,138 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.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

In October 2002, Baytex signed a five-year crude oil supply agreement with a U.S. based refining company. This agreement calls for the delivery, beginning in January 2003, of up to 20,000 Bbl/d of Lloyd Blend oil production at a fixed differential of 29 percent of the West Texas Intermediate price. This pricing arrangement effectively removes the additional pricing volatility associated with heavy oil on three-quarters of our heavy oil production. This contract forms part of our risk management program and should help to reduce the impact on our cash flow from dramatic swings in commodity prices in the future.

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 the Trust. 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% 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% 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 exist 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 Plan 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% of the "Average Market Price" (which is defined in the DRIP Plan 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 Plan. The DRIP Plan is presently available to Canadian Unitholders only. Residents of the United States may not participate in the DRIP Plan 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% of our 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 are the Doig, Halfway, Charlie Lake, Baldonnel and Cretaceous zones. The assets represented a new core area for us and are 100% operated with an average working interest of 91%. 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 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 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% of our 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, Baytex's second largest producing area within its heavy oil operations. The expanded Celtic/Tangleflags operating region will improve economies of scale and allow for better control over costs. The acquisition also 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.

Significant Acquisitions

We have not completed any significant acquisitions or entered into any significant probable acquisition within or since the completion of our most recently completed financial year for which disclosure is required under Part 8 of National Instrument 51-102.

Trends

There are a number of trends in the oil and gas industry that are shaping the near term future of our business. One trend has been the continuation of oil and gas companies converting to royalty trusts. These conversions occur because the equity markets generally value trusts at higher multiples than exploration and development firms.

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 is the continuing volatility of commodity prices. World oil inventories experienced a significant drawdown in the last few years and the rate of recovery will largely be dependent on Iraq's export recovery, the resolution of middle-eastern political conflicts, and OPEC's production discipline. As long as inventories remain low, the high crude oil prices the industry experienced over the past years could continue. Natural gas inventories are at more stable levels; however, natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America. As weather is a key factor in determining gas demand, future gas prices are highly unpredictable.

Although commodity prices are higher than historical levels, the appreciation of the Canadian dollar in 2004 and 2005 relative to its US counterpart has offset a portion of the economic benefit of higher prices on Canadian oil and gas producers including trusts. Any further strengthening of the Canadian dollar may result in decreased revenue and affect royalty trusts' ability to maintain current distribution levels.

RISK FACTORS

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

We are dependant 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, the 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. The 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, blow-outs, craterings and fires, all of which could result in personal injuries, loss of life and damage to our property and others. In addition, we have liability insurance policies in place, in such amounts as we consider adequate, however, we are not be fully insured against all of these risks, nor are all such risks insurable.

We are dependent on our operators to produce and market our property

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. 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. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of Baytex to certain properties. A reduction of the income from the NPI could result in such circumstances.

Our business depends on the level of activity in the oil and gas industry, which is significantly affected by volatile oil and gas prices.

Our business depends on the level of activity in offshore oil and gas exploration, development and production in markets worldwide. Oil and gas prices, market expectations of potential changes in these prices and a variety of political and economic factors significantly affect this level of activity. However, higher commodity prices do not necessarily translate into increased drilling activity since our customers' expectations of future commodity prices typically drive demand for our rigs. Oil and gas prices are extremely volatile and are affected by numerous factors beyond our control, including:

- the political environment of oil-producing regions, including uncertainty or instability resulting from an escalation or additional outbreak of armed hostilities in the Middle East or other geographic areas or further acts of terrorism in the United States or elsewhere;
- worldwide demand for oil and gas;
- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;
- available pipeline and other oil and gas transportation capacity;
- the ability of oil and gas companies to raise capital;
- weather conditions in the United States and elsewhere;
- the ability of the Organization of Petroleum Exporting Countries, commonly called OPEC, to set and maintain production levels and pricing;
- the level of production in non-OPEC countries;
- the policies of the various governments regarding exploration and development of their oil and gas reserves; and
- advances in exploration and development technology.

Distributions may be affected by capital expenditure

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.

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 $250 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.

Reserve figures are only estimates and may require revision

Although we, together with Sproule, have carefully prepared the reserve figures included herein 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. Probable reserves estimated for properties may require revision based on the actual development strategies employed to prove such reserves. Declines in our reserves which are not offset by the acquisition or development of additional reserves may reduce the underlying value of Trust Units to Unitholders. Trust Units will have no value once all of the oil and natural gas reserves of Baytex have been produced. As a result, holders of Trust Units will have to obtain the return of capital invested out of cash flow derived from their investment in such Trust Units.

We face competition from competitors with greater resources

Some of our competitors have greater financial and human resources than do we. Their greater capabilities in these areas may enable them to:

- compete more effectively;
- better withstand industry downturns; and
- retain skilled personnel.

We may not be able to satisfy our future environmental and reclamation obligations

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean-up orders in respect of Baytex or the properties. Such legislation may be changed to impose higher standards and potentially more costly obligations on Baytex. Baytex provides for the necessary amounts in its annual capital budget for the purpose of funding its currently estimated future environmental and reclamation obligations based on its current knowledge. There can be no assurance that the Trust will be able to satisfy its actual future environmental and reclamation obligations.

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

Baytex's operations are subject to a variety of federal and provincial laws and regulations, including laws and regulations relating to the protection of the environment.

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other so-called "greenhouse gases". Our exploration and production facilities and other operations and activities emit greenhouse gases 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. While the protocol became legally binding on February 16, 2005, details of any specific requirements have not been released. However, the Canadian Association of Petroleum Producers has secured specific non-binding limitations from the Government of Canada on reductions required by the oil and gas industry and the cost thereof. On the basis of these limitations, the impact of the Kyoto Protocol on our operations is currently not expected to be material.

Future federal legislation, together with provincial emission reduction requirements, such as those proposed in Alberta's Bill 37 Climate Change and Emissions Management, may require the reduction of emissions or emissions intensity of our operations and facilities beyond what was agreed to by the Canadian Association of Petroleum Producers. The direct or indirect costs of these regulations may adversely affect our business.

We may have delay in cash distributions

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 Baytex, 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 the 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.

Baytex will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections, Baytex's initial production levels and reserves will decline.

Baytex's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent on Baytex's success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, Baytex's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, Baytex's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that Baytex is 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 Baytex 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

Variations in interest rates could result in a significant change in the amount we pay to service debt, potentially impacting distributions to Unitholders.

In addition, the exchange rate for the Canadian dollar versus the U.S. dollar has increased significantly over the last 24 months, resulting in the receipt by us of fewer Canadian dollars for our production which may affect future distributions. We have initiated certain hedges to mitigate these risks. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates may impact future distributions and the future value of our reserves as determined by independent evaluators.

Our prior distribution may not be reflective of future distribution

Our historical distribution 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 Baytex 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

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.

In particular, generally speaking, the *Income Tax Act* (Canada) provides that a trust will permanently lose its "mutual fund trust" status (which is essential to the income trust structure) if it is established or maintained primarily for the benefit of non-residents of Canada (which is generally interpreted to mean that the majority of unitholders must not be non-residents of Canada), unless at

all times after February 21, 1990, "all or substantially all" of the trust's property consisted of property other than taxable Canadian property (the "**TCP Exception**"). We are currently able to take advantage of the TCP Exception.

On March 23, 2004 the Canadian federal government announced proposed changes to the *Income Tax Act* (Canada) which would have effectively eliminated, over a period of time, the TCP Exception currently relied on by us to maintain our mutual fund trust status, and, if implemented, would require us to comply with the requirement that it "not be maintained primarily for the benefit of non-residents". In response to submissions from and discussions with stakeholders, the Canadian federal government suspended the implementation of those proposed amendments. The Canadian Minister of Finance indicated in the February 23, 2005 federal budget that further consultations would be pursued with stakeholders on taxation issues related to income trusts and other flow-through entities. On September 8, 2005, the Canadian Department of Finance released a discussion paper on these matters and invited interested parties to make submissions to the Department of Finance. On November 23, 2005, the former Canadian Minister of Finance issued a news release announcing that no change would be made to the tax treatment of income trusts in Canada and calling an end to the consultation process initiated in September 2005.

Notwithstanding the above, there is no assurance that the TCP Exception will continue to be available to the Trust or that the Canadian federal government will not introduce new changes or proposals to tax regulations directed at non-resident ownership which, depending upon our level non-resident ownership, could result in us losing our mutual fund trust status or could otherwise detrimentally affect us and the market price of the Trust Units. We intend to continue to take the necessary measures in order to ensure that we continue to qualify as a mutual fund trust under the *Income Tax Act* (Canada). There would be material adverse consequences if we lost our status as a mutual fund trust under Canadian tax laws.

However, 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.

Additionally, legislation may be implemented to limit the investment in income funds and royalty trusts by certain investors or to change the manner in which these entities are taxed. Tax authorities having jurisdiction over us or our Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practices 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.

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 the detriment of us or the detriment of our Unitholders.

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 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 ("**RESTs**") 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 1% 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 our 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* ".

We have non-resident ownership restrictions of our Trust Units

In order for us to maintain our status as a mutual fund trust under the Tax Act, we must not be established or maintained primarily for the benefit of non-residents of Canada ("non-residents") within the meaning of the Tax Act. The Trust Indenture provides that if at any time we or Baytex becomes aware that the beneficial owners of 50% or more of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, we, by or through Baytex on our behalf, will take such action as may be necessary to carry out the foregoing intention.

Our expenses and other deductions may be challenged by taxing authorities

Generally, oil and gas income trusts including this income trust 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 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 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 the Trust. 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. Our

primary assets will be the Notes, common shares, the NPI and other investments in securities. The price per Trust Unit is a function of anticipated distributable income, the properties acquired by Baytex, and Baytex's ability to effect long-term growth in the value of the Trust. 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 oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

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

Our Trust Units have a limited 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 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. Cash redemptions are subject to limitations. See "*Additional Information Respecting Baytex Energy Trust - - Redemption Right*".

Our Unitholders may not have limited liability

The Trust Indenture provides that no Unitholder will be subject to any liability in connection with the Trust or its affairs or obligations and, in the event that a court determines that Unitholders are subject to any such liabilities, the liabilities will be enforceable only against, and will be satisfied only out of, the Unitholder's share of our assets.

The Trust Indenture provides that all written instruments signed by us or on our behalf 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 the Trust 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.

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.

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.

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 the Corporation 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 the Trust and Baytex and a director or officer of Baytex.

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 Tax Act 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%* 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 its auditors and some of its 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.

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

Baytex Energy Trust

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 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 other intercorporate debt 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 permits us to use between 30% and 40% 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% 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.

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 - 5 th 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% of the gross proceeds from the sale of production attributable to such property interests for such month exceed ninety-nine (99%) percent of certain deductible costs for such period. Baytex is entitled to set off amounts reimbursable to it against NPI payments payable by Baytex. The term of the 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. Similar Notes have been issued by Baytex to us for inter-corporate debt from time to time.

The Notes are unsecured, payable on demand and bear interest from the date of issue at an interest rate equal to 12% 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 5 days after demand.

Disclosure of Reserves Data and Other Oil and Gas Information

The statement of reserves data and other oil and gas information set forth below (the " **Statement**") is dated December 31, 2005. The effective date of the Statement is December 31, 2005 and the preparation date of the Statement is February 24, 2006. 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.

The reserves data set forth below (the "**Reserves Data**") are based upon the Sproule Report. The Reserves Data summarizes our oil, liquids and natural gas reserves and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. Constant and forecast prices were provided by Sproule as at December 31, 2005. The Reserves Data conforms with the requirements of NI 51-101. We engaged Sproule to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. See also "*Definitions and Other Notes*" below.

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

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

gas and natural gas liquid reserves may be greater than or less than the estimates provided herein. For more information as to the risks involved, see "*Risk Factors*".

We are classified as a unit trust for income tax purposes, and are taxable on income not distributed to public Unitholders. We have and expect to continue to allocate all of our taxable income to Unitholders. Accordingly, no provision for income taxes is required at the Trust level and all information our oil and gas reserves has been presented on a pre-tax basis only.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	3,450.7	3,120.5	23,288.6	20,600.0	96.0	80.6	2,347.3	2,033.3	45,083.9	39,188.5
Developed Non-Producing	531.2	437.6	19,468.5	16,579.8	11.6	9.6	676.7	568.0	22,613.5	19,179.2
Undeveloped	1,671.6	1,427.6	28,731.5	25,399.2	19.1	14.1	615.1	485.3	34,194.1	29,661.0
TOTAL PROVED	5,653.5	4,985.7	71,488.6	62,579.0	126.7	104.3	3,639.1	3,086.6	101,891.5	88,028.8
PROBABLE										
Developed Producing	1,791.7	1,636.7	7,440.0	6,558.5	34.7	29.5	536.9	460.1	15,552.9	13,571.5
Developed Non-Producing	109.8	92.0	5,271.7	4,518.2	4.0	3.4	112.2	93.0	6,167.7	5,277.1
Undeveloped	526.7	451.3	13,640.9	11,579.9	12.8	10.2	608.0	470.8	16,905.7	14,198.8
TOTAL PROBABLE	2,428.2	2,180.0	26,352.6	22,656.6	51.5	43.1	1,257.1	1,023.9	38,626.4	33,047.3
TOTAL PROVED PLUS PROBABLE	8,081.6	7,165.7	97,841.2	85,235.6	178.2	147.4	4,896.2	4,110.4	140,517.9	121,076.1

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT				
RESERVES CATEGORY	0% ($ Million)	5% ($ Million)	10% ($ Million)	15% ($ Million)	20% ($ Million)
PROVED					
Developed Producing	1,245.0	1,083.1	958.9	866.4	794.8
Developed Non-Producing	410.0	312.2	247.8	203.1	170.7
Undeveloped	543.3	397.5	300.0	232.2	183.2
TOTAL PROVED	2,198.2	1,792.8	1,506.7	1,301.6	1,148.8
PROBABLE					
Developed Producing	447.2	305.2	232.8	188.4	158.2
Developed Non-Producing	117.1	75.8	53.6	40.1	31.2
Undeveloped	304.3	200.3	139.6	101.8	77.1
TOTAL PROBABLE	868.7	581.3	425.9	330.3	266.5
TOTAL PROVED PLUS PROBABLE	3,066.8	2,374.1	1,932.6	1,631.9	1,415.3

Note:
(1) Revenue is net of gas contracts and hedges, ARTC and the Saskatchewan Capital Tax Surcharge.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($ Million)	ROYALTIES ($ Million)	OPERATING COSTS ($ Million)	DEVELOPMENT COSTS ($ Million)	WELL ABANDONMENT COSTS ($ Million)	FUTURE NET REVENUE BEFORE INCOME TAXES ($ Million)
PROVED						
Developed Producing	2,083.8	279.4	513.5	0.6	45.4	1,244.9
Developed Non-Producing	789.6	123.5	222.8	33.3	—	410.0
Undeveloped	1,230.1	168.4	298.8	219.6	—	543.3
TOTAL PROVED	4,103.5	571.4	1,035.1	253.5	45.4	2,198.2
PROBABLE						
Developed Producing	720.8	88.3	185.3	—	—	447.2

Developed Non-Producing	215.7	31.9	64.9	1.8	—	117.1
Undeveloped	601.4	96.9	130.3	69.8	—	304.4
TOTAL PROBABLE	1,538.0	217.2	380.4	71.6	—	868.7
TOTAL PROVED PLUS PROBABLE	5,641.5	788.6	1,415.5	325.1	45.4	3,066.9

Note:

(1) Revenue is net of gas contracts and hedges, ARTC and the Saskatchewan Capital Tax Surcharge.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($ Million)
Proved Reserves	Light and Medium Crude Oil (excluding solution gas and other by-products)	145.6
	Heavy Oil (including solution gas and other by-products)	738.4
	Natural Gas (including by-products and solution gas from oil wells)	628.2
Proved Plus Probable Reserves	Light and Medium Crude Oil (excluding solution gas and other by-products)	187.4
	Heavy Oil (including solution gas and other by-products)	935.9
	Natural Gas (including by-products and solution gas from oil wells)	814.7

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS

	RESERVES									
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS		TOTAL RESERVES	
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Bcf)	Net (Bcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED										
Developed Producing	3,281.2	2,962.8	23,134.9	20,389.4	94.9	79.7	2,342.6	2,030.1	44,574.9	38,659.2
Developed Non-Producing	531.2	437.6	19,409.0	16,476.4	11.6	9.6	676.7	568.0	22,552.4	19,075.1
Undeveloped	1,660.2	1,416.7	28,722.0	25,339.0	19.0	14.1	615.1	485.3	34,168.4	29,591.1
TOTAL PROVED	5,472.7	4,817.1	71,265.9	62,204.7	125.5	103.3	3,634.4	3,083.4	101,295.7	87,325.4
PROBABLE										
Developed Producing	1,708.7	1,560.2	7,399.1	6,512.1	34.1	28.9	534.6	458.3	15,319.5	13,354.6
Developed Non-Producing	109.5	91.8	5,265.0	4,494.7	4.0	3.4	111.3	92.5	6,156.6	5,250.1
Undeveloped	523.7	448.4	13,621.9	11,443.8	12.8	10.2	608.0	470.8	16,882.7	14,059.9
TOTAL PROBABLE	2,342.0	2,100.4	26,286.0	22,450.6	50.9	42.5	1,253.9	1,021.8	38,358.8	32,664.6
TOTAL PROVED PLUS PROBABLE	7,814.7	6,917.6	97,551.9	84,655.3	176.4	145.8	4,888.3	4,105.2	139,654.5	119,990.0

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT				
RESERVES CATEGORY	0% ($ Million)	5% ($ Million)	10% ($ Million)	15% ($ Million)	20% ($ Million)
PROVED					
Developed Producing	1,068.3	979.0	883.8	808.8	749.3
Developed Non-Producing	400.7	303.2	239.4	195.6	164.0
Undeveloped	508.0	368.5	275.9	211.9	166.0
TOTAL PROVED	1,977.0	1,650.7	1,399.2	1,216.2	1,079.3
PROBABLE					
Developed Producing	380.9	263.6	204.2	167.6	142.5

Developed Non-Producing	116.3	74.4	52.1	38.7	30.0
Undeveloped	290.9	188.1	129.2	93.2	70.1
TOTAL PROBABLE	788.1	526.1	385.5	299.6	242.7
TOTAL PROVED PLUS PROBABLE	2,765.1	2,176.8	1,784.7	1,515.8	1,322.0

Note:
(1) Revenue is net of gas contracts and hedges, ARTC and the Saskatchewan Capital Tax Surcharge.

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($ Million)	ROYALTIES ($ Million)	OPERATING COSTS ($ Million)	DEVELOPMENT COSTS ($ Million)	WELL ABANDONMENT COSTS ($ Million)	FUTURE NET REVENUE BEFORE INCOME TAXES ($ Million)
PROVED						
Developed Producing	1,950.5	263.2	536.9	0.6	81.5	1,068.3
Developed Non-Producing	815.5	129.4	250.2	35.2	—	400.7
Undeveloped	1,242.2	166.5	335.7	232.0	—	508.0
TOTAL PROVED	4,008.3	559.1	1,122.9	267.8	81.5	1,977.0
PROBABLE						
Developed Producing	679.1	82.3	215.9	—	—	380.9
Developed Non-Producing	230.1	34.8	77.1	2.0	—	116.2
Undeveloped	623.6	103.1	152.4	77.2	—	290.9
TOTAL PROBABLE	1,532.9	220.2	445.4	79.2	—	788.1
TOTAL PROVED PLUS PROBABLE	5,541.2	779.3	1,568.3	347.0	81.5	2,765.2

Note:
(1) Revenue is net of gas contracts and hedges, ARTC and the Saskatchewan Capital Tax Surcharge.

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($ Million)
Proved Reserves	Light and Medium Crude Oil (excluding solution gas and other by-products)	125.3
	Heavy Oil (including solution gas and other by-products)	711.3
	Natural Gas (including by-products and solution gas from oil wells)	562.6
Proved Plus Probable Reserves	Light and Medium Crude Oil (excluding solution gas and other by-products)	159.6
	Heavy Oil (including solution gas and other by-products)	915.1
	Natural Gas (including by-products and solution gas from oil wells)	709.9

Definitions and Other Notes

In the tables set forth above in "*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.

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

"**Economic Assumptions**" will be the prices and costs used in the estimate, namely:

(a) constant prices and costs as at the last day of the Trust's financial year; and

(b) forecast prices and costs.

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.

Additional clarification of certain levels associated with reserve estimates and the effect of aggregation is provided in the COGE Handbook.

4. ARTC is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. We qualify for the maximum ARTC.

5. "**Exploration 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. Numbers may not add due to rounding.

11. Estimated future well abandonment costs related to us have been taken into account by Sproule in determining reserves that should be attributed to us. In determining the aggregate future net revenue, reasonable estimated future well abandonment costs, net of downhole equipment salvage value, were deducted from the gross revenue amount.

12. Both the constant and forecast price and cost assumptions assumed the continuance of current laws and regulations.

13. The extended character of all factual data supplied to Sproule was accepted by Sproule as represented. No field inspection was conducted.

Pricing Assumptions

The following sets forth the benchmark reference prices, as at December 31, 2005, reflected in the Reserves Data. The forecast prices and cost assumptions were provided to us by Sproule, our independent qualified reserves evaluator.

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 we are 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).

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, 2005, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2005
FORECAST PRICES AND COSTS

	OIL					
Year	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40º API ($Cdn/Bbl)	Hardisty Heavy 12º API ($Cdn/Bbl)	NATURAL GAS AECO Gas Price ($Cdn/Mmbtu)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Historical						
2001	25.94	39.06	18.05	6.23	2.0	0.646
2002	26.09	40.12	27.58	4.04	2.7	0.637
2003	31.14	43.23	27.39	6.66	2.5	0.716
2004	41.41	52.91	30.4	6.87	1.3	0.826
2005	56.45	69.28	34.39	8.58	1.6	0.850
Forecast						
2006	60.81	70.07	37.07	11.58	2.5	0.850
2007	61.61	70.99	37.29	10.84	2.5	0.850
2008	54.60	62.73	34.23	8.95	2.5	0.850
2009	50.19	57.53	32.27	7.87	1.5	0.850
2010	47.76	54.65	31.15	7.57	1.5	0.850
Thereafter.	Various escalation Rates					

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

Constant Prices and Costs

These are prices and costs that are:

(a) Our prices and costs as of December 31, 2005, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) if, and only to the extent that, there are fixed or presently determinable future prices of costs to which we are 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).

The constant crude oil and natural gas benchmark reference pricing and the exchange rate utilized in the Sproule Report were as follows:

SUMMARY OF PRICING ASSUMPTIONS (1)
AS OF DECEMBER 31, 2005
CONSTANT PRICES AND COSTS

OIL

Year	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)	EXCHANGE RATE(2) ($US/$Cdn)
December 31, 2005	61.04	68.15	40.63(3)	9.99	0.8577

Notes:
(1) This summary table identifies benchmark reference pricing schedules that might apply to a reporting issuer.
(2) The exchange rate used to generate the benchmark reference prices in this table.
(3) $40.63 for 2006 and 2007, and $30.65 for subsequent years.

Weighted average prices realized by us for the year ended December 31, 2005, were $8.22/Mcf for natural gas, $53.84/bbl for light crude oil and NGLs, and $37.38/bbl for heavy oil. The heavy oil price includes the effect of our long term sales contract.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF TRUST NET RESERVES
BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS

	Light and Medium Crude Oil			Heavy Oil		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2004	5,637	2,165	7,802	49,224	21,841	71,065
Extensions	277	36	313	6,056	3,020	9,076
Discoveries	14	9	23	350	143	493
Technical Revisions	(462)	(144)	(606)	626	(4,123)	(3,497)
Acquisitions	—	—	—	13,344	1,502	14,846
Dispositions	—	—	—	(1,683)	(281)	(1,964)
Economic Factors	90	35	125	788	349	1,137
Production	(739)	—	(739)	(6,500)	—	(6,500)
December 31, 2005	4,817	2,101	6,918	62,205	22,451	84,656

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
December 31, 2004	2,909	454	3,363	91,600	36,800	128,400
Extensions	892	519	1,411	14,552	6,412	20,964
Discoveries	131	15	146	1,286	170	1,456
Technical Revisions	(459)	27	(432)	8,452	(2,449)	6,003
Acquisitions	—	—	—	3,764	1,029	4,793
Dispositions	—	—	—	—	—	—
Economic Factors	46	7	53	1,466	589	2,055
Production	(436)	—	(436)	(17,800)	—	(17,800)
December 31, 2005	3,083	1,022	4,105	103,320	42,551	145,871

	Oil Equivalent		
	Proved (Mbboe)	Probable (Mbboe)	Proved + Probable (Mbboe)
December 31, 2004	73.0	30.6	103.6
Extensions	9.7	4.6	14.3
Improved Recovery	0.7	0.2	0.9
Technical Revisions	1.1	(4.6)	(3.5)
Acquisitions	14.0	1.7	15.6
Dispositions	(1.7)	(0.3)	(2.0)
Economic Factors	1.2	0.5	1.7
Production	(10.6)	—	(10.6)
December 31, 2005	87.3	32.7	120.0

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

	Light and Medium Crude Oil	Heavy Oil

	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
December 31, 2004	6,386	2,431	8,817	55,874	24,887	80,761
Extensions	340	43	383	7,009	3,498	10,507
Discoveries	19	12	31	426	175	601
Technical Revisions	(505)	(183)	(688)	520	(4,148)	(3,628)
Acquisitions	—	—	—	15,777	1,776	17,553
Dispositions	—	—	—	(1,800)	(300)	(2,100)
Economic Factors	102	39	141	894	398	1,292
Production	(870)	—	(870)	(7,434)	—	(7,434)
December 31, 2005	5,472	2,342	7,814	71,266	26,286	97,552

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)
December 31, 2004	3,672	590	4,262	110,999	44,101	155,100
Extensions	1,113	664	1,777	19,691	8,315	28,006
Discoveries	149	17	166	1,636	213	1,849
Technical Revisions	(825)	(26)	(851)	8,631	(3,770)	4,861
Acquisitions	—	—	—	4,856	1,297	6,153
Dispositions	—	—	—	—	—	—
Economic Factors	59	9	68	1,776	706	2,482
Production	(533)	—	(533)	(22,052)	—	(22,052)
December 31, 2005	3,635	1,254	4,889	125,537	50,862	176,399

	Oil Equivalent		
	Proved	Probable	Proved + Probable
	(Mbboe)	(Mbboe)	(Mbboe)
December 31, 2004	84.4	35.3	119.7
Extensions	11.7	5.6	17.3
Improved Recovery	0.9	0.2	1.1
Technical Revisions	0.6	(5.0)	(4.4)
Acquisitions	16.6	2.0	18.6
Dispositions	(1.8)	(0.3)	(2.1)
Economic Factors	1.4	0.6	1.9
Production	(12.5)	—	(12.5)
December 31, 2005	101.3	38.4	139.7

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR

PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	2005 ($ Million)
Estimated Future Net Revenue at Beginning of Year	1,087.0
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties(1)	(352.6)
Net Change in Prices, Production Costs and Royalties Related to Future Production(2)	254.2
Changes in Previously Estimated Development Costs Incurred During the Period(2)	51.5
Changes in Estimated Future Development Costs(2)	(115.5)
Extensions and Improved Recovery(2)	174.2
Discoveries	11.0
Acquisitions of Reserves(2)	176.2
Dispositions of Reserves(2)	(9.9)
Net Change Resulting from Revisions in Quantity Estimates (Technical Revisions)	36.1
Accretion of Discount(3)	102.2
Miscellaneous Changes	92.3
Estimated Future Net Revenue at End of Year	1,506.7

Note:
(1) Undiscounted before income tax.
(2) Discounted before income tax.
(3) Ten percent (10%) of beginning of year net present value, before income tax.

Additional Information Relating to Reserves Data

Proved and Probable 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.

The funds available for capital expenditures under a trust business model are lower than for a traditional oil and gas business model as a portion of the cash flow that a trust generates is distributed to its unitholders. As a result, we are required to develop our assets in a more 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 and probable undeveloped reserves over the next six 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 analyze 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.

Significant Factors or Uncertainties

We have a significant amount of proved non-producing and proved undeveloped reserves assigned to the Celtic, Tangleflags and Carruthers heavy oil properties in Saskatchewan, the Ardmore and Cold Lake heavy oil properties in Alberta and to the Stoddart, British Columbia and Leahurst, Alberta light oil and gas properties. As well we have a significant amount of probable non-producing and probable undeveloped reserves assigned to these same properties. At the current prices, these development activities are economic. However, should oil and natural gas prices fall materially, these activities may not be economic and we could defer their implementation.

Future Development Costs

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

	Forecast Prices and Costs		Constant Prices and Costs
Year	Proved Reserves ($ Million)	Proved Plus Probable Reserves ($ Million)	Proved Reserves ($ Million)
2006	54.8	57.3	54.8
2007	43.9	48.4	42.8
2008	44.3	53.3	42.1
2009	69.4	77.5	64.4
2010	20.6	30.4	18.9
Total Undiscounted (all years)	267.8	347.0	253.5
Total Discounted at 10%/year	189.5	224.0	173.8

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 30 - 40% of cash flow to assist in funding development activities.

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

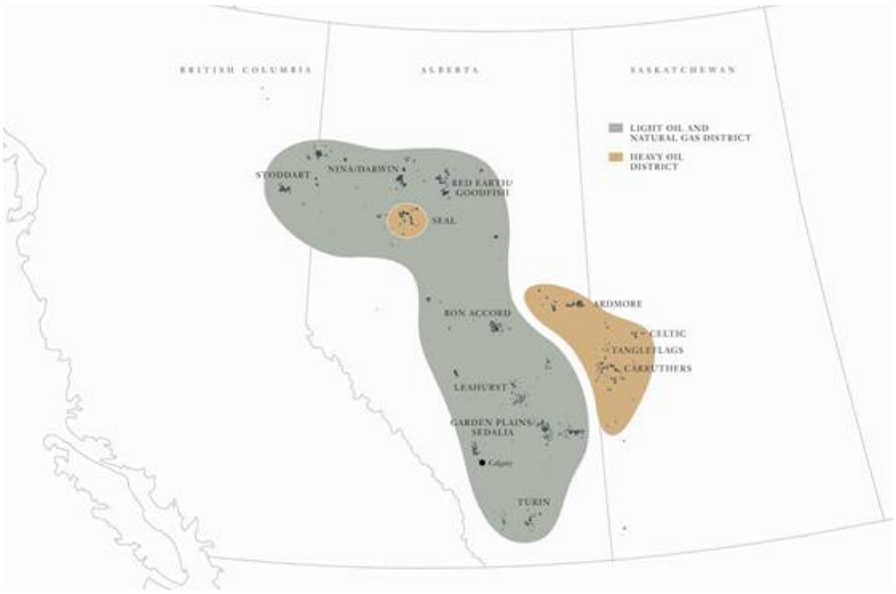
The interest or other costs of external funding are not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any property 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, 2005. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2005. Production information represents average working interest production, for the year ended December 31, 2005, except where otherwise indicated.

Baytex's crude oil and natural gas operations are organized into two operating districts - the Heavy Oil District and the Light Oil and Natural Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Baytex has established several geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each district. Each team has a mandate to apply its specific knowledge and expertise to its operating area. This focused approach aids in the evaluation and execution of exploration, development and acquisition opportunities and improves cost efficiency.



Heavy Oil District

The Heavy Oil District accounts for approximately 60 percent of current production, three-quarters of oil-equivalent reserves and one-half of cash flow from operations. Baytex's heavy oil operations consist entirely 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 11º to 18º API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. The 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.

In 2005, production in the Heavy Oil District averaged approximately 21,265 Bbl/d of heavy oil and 7.5 MMcf/d of natural gas (22,515 boe/d). Baytex drilled 67 gross (65.4 net) wells in the Heavy Oil District resulting in 59 (57.4 net) oil wells, one (1.0 net) gas well, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96 percent (95 percent net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River/Seal heavy oil sands. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining the Trust's overall production rate. Because of Baytex's large inventory of heavy oil investment projects, the Trust is able to regulate the timing and level of its capital investment program while striving to maintain production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus on the Peace River/Seal oilsands area and the newly acquired Celtic property, along with continued drilling and re-completion activity throughout Baytex's other properties. Our net undeveloped lands in this district totalled approximately 313,900 acres at year-end 2005.

Ardmore, Alberta: 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 2005 was approximately 4,100 Bbl/d of oil and 800 Mcf/d

of natural gas (4,200 boe/d). Current production is approximately 3,900 Bbl/d and 700 Mcf/d of natural gas (4,000 boe/d). Sixteen successful oil wells and no dry holes were drilled in the area during 2005. During 2006, Baytex anticipates drilling eight to ten wells. In 2005, operating expenses were maintained at $5.50/boe by using a Company-owned water disposal facility and continuing to conserve solution gas that is produced in conjunction with the heavy oil. Our net undeveloped lands were 41,800 acres at year-end 2005.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. A typical vertical oil well will initially produce at 40 Bbl/d and provide an ultimate recovery of approximately 60,000 barrels of reserves. During 2005, average production was approximately 2,700 Bbl/d of heavy oil and 900 Mcf/d of natural gas (2,900 boe/d). Five successful oil wells were drilled in South Carruthers during 2005. This area represents a very stable production base with continued development drilling of about three to five wells annually. Current production is approximately 2,900 Bbl/d and 900 Mcf/d of natural gas (3,100 boe/d). Our net undeveloped lands were 12,400 acres at year-end 2005.

Celtic, Saskatchewan: This producing property was acquired in October 2005, in a transaction which included approximately 1,900 Bbl/d of Steam Assisted Gravity Drainage (SAGD) production. The SAGD production was divested at the end of 2005, leaving Baytex with the cold heavy oil and gas production. At the time of the purchase, cold production rates were approximately 1,600 Bbl/d of heavy oil and 0.9 MMcf/d of natural gas. Current production has increased to over 3,000 boe/d. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base (455 million barrels of original oil in-place) within multiple prospective horizons. The Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Also like Tangleflags, the heavy oil is relatively gas-saturated and the

existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2006, Baytex expects to drill 30 to 40 wells and recomplete 25 to 30 additional wells. In addition, it is anticipated that between 0.5 and 1.0 MMcf/d of solution gas sales will be added through on-going tie-in projects. Our net undeveloped lands were 7,100 acres at year-end 2005.

Cold Lake, Alberta: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily generated from the Colony formation. Average oil production was 700 Bbl/d for 2005, during which time Baytex drilled two (1.8 net) oil wells. Current production is approximately 670 bbl/d. Up to five new drills are anticipated during 2006. Company net undeveloped lands were 15,000 acres at year-end 2005.

Marsden/Epping/Macklin/Silverdale, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that range up to 18 API. Initial production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30 percent of the original oil in-place because many of the oil pools in this area have a strong natural water drive. Average oil production in this area during 2005 was approximately 4,400 bbl/d. Eight oil wells were drilled in 2005 and current oil production is approximately 3,600 bbl/d. In addition, a solution gas tie-in project that currently produces 300 Mcf/d of natural gas was completed at Marsden. During 2006, a 300 Mcf/d solution gas project at Macklin is expected to be put on-stream and eight to 10 new wells are planned. Our net undeveloped lands were 19,600 acres at year-end 2005.

Seal, Alberta: Seal is a highly prospective property located in the Peace River oilsands area of northwest Alberta. Baytex holds a 100 percent working interest in approximately 100 sections of long-term oil sands leases. These oil deposits can be produced through horizontal well-bores at initial rates of approximately 150 Bbl/d without employing the more capital intensive steam injection methods. A four-well stratigraphic test program completed during the first quarter of 2005 proved up significant extensions to our current development area located on the western block of these land holdings. Six horizontal wells drilled in late 2004 and early 2005 are currently producing approximately 500 bbl/d. The prospective undeveloped area of this western block of Baytex lands comprises over 25,000 acres, and during 2006 we will drill three additional stratigraphic test wells to further delineate this acreage. In addition, two multi-lateral horizontal wells drilled with upper and lower production legs to more efficiently drain the 20 meter thick oilsand deposit will be completed and brought on-stream in the first half of 2006. Operators of adjoining lands are pursuing aggressive development programs that will contribute to vital infrastructure and allow enhanced marketing solutions for the region. As the region continues to develop, the Seal property will take an increasingly more prominent role in the Trust's production profile. Our net undeveloped lands in this area were 67,000 acres at year-end 2005.

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 longer-term development potential through a considerable number of uphole recompletion opportunities. Average production during 2005 was approximately 3,500 Bbl/d of heavy oil and 1.4 MMcf/d of natural gas (3,700 boe/d). Current production is approximately 3,000 bbl/pd and 2.1 MMcf/d. The growth in natural gas production was achieved

through the conservation of solution gas produced in conjunction with the heavy oil. During 2006, Baytex plans to add three to five wells, conduct 10 to 20 recompletions and continue tie-in of solution gas production. Our net undeveloped lands were 10,200 acres at year-end 2005.

Light Oil and Natural 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 currently generate approximately half of our cash flow. When Baytex converted to an energy trust in 2003, we produced approximately 12,000 boe/d of light oil and natural gas concentrated in southeastern and northern Alberta. Over the last two and a half years, Baytex's light oil and gas production has grown to its current level of approximately 14,000 boe/d through a combination of acquisitions and development activities. Moreover, the geographic scope of our light oil and gas operations has expanded to southwest Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Light Oil and Natural Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2005, production averaged 52.9 MMcf/d of natural gas and 3,842 bbl/d of light oil and NGL (12,662 boe/d). In 2005, the District drilled 51 (41.9 net) wells resulting in 40 (33.4 net) gas wells, five (3.0 net) oil wells, and six (5.5 net) dry wells for a success rate of 88 percent (88 percent net). Our undeveloped lands in this district were approximately 425,600 net acres at year-end 2005.

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production, which is from the Belly River, Viking and Mannville formations, averaged approximately 6.0 MMcf/d of gas and 300 Bbl/d of light oil (1,300 boe/d) in 2005. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. Baytex plans to drill three wells in this area during 2006. Our net undeveloped lands were 27,400 acres at year-end 2005.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Company-operated gas plants. Production during 2005 averaged approximately 4.0 MMcf/d (700 boe/d). Baytex plans to drill three wells during 2006 in this area. Our net undeveloped lands were 52,000 acres at year-end 2005.

Leahurst, Alberta: Production averaged approximately 5.0 MMcf/d (800 boe/d) in 2005 from this multi-zone, year-round access area. Natural gas from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Company-operated. In 2005, Baytex drilled 14 (11.3 net) wells for coal-bed methane production from the Horseshoe Canyon Coals (three of which were also completed in the Belly River formation), and four (4.0 net) Mannville natural gas wells. In 2006, Baytex may drill up to 12 Horseshoe Canyon CBM / Belly River wells and one Mannville well in the Leahurst area. Our net undeveloped lands were 20,600 acres at year-end 2005.

Red Earth/Goodfish, Alberta: This winter-access, multi-zone property was acquired by Baytex in 1997. Relatively shallow decline oil production from Granite Wash and Slave Point pools is treated at two Company-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Company-operated. Production during 2005 from this area averaged approximately 6.0 MMcf/d and 900 Bbl/d of hydrocarbon liquids (1,900 boe/d). Baytex plans to drill four wells during 2006 in the Red Earth/Goodfish area. Our net

undeveloped lands were 49,900 acres at year-end 2005.

Richdale/Sedalia, Alberta: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition. During 2005, production averaged approximately 9.0 MMcf/d and 20 Bbl/d of light oil (1,500 boe/d). This area has advantages of year-round access and multi-zone potential (Second White Specks, Viking and Mannville). Most of the gas production is processed by two Company-operated gas plants. Baytex plans to drill three wells during 2006 in this area. Our net undeveloped lands were 60,300 acres at year-end 2005.

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 Company-operated batteries and natural gas is compressed at four Company-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production during 2005 from this area averaged approximately 12 MMcf/d and 1,700 Bbl/d of natural gas (3,700 boe/d). Baytex drilled nine (9.0 net) wells in 2005 resulting in eight (8.0 net) gas wells and one (1.0 net) abandoned well, and plans to drill six wells and recomplete three wells in 2006. Our net undeveloped lands were 34,500 acres at December 31, 2005.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2005 averaged approximately 2.0 MMcf/d and 700 Bbl/d of light oil (1,000 boe/d). Production comes from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Company-operated batteries and gas is processed at two outside-operated gas plants. Baytex plans to drill three wells and recomplete five wells during 2006 in the Turin area. Our net undeveloped lands were 29,500 acres at December 31, 2005.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2005.

	Light Oil and NGL (Bbl/d)	Heavy Oil (Bbl/d)	Gas (Mcf/d)
Ardmore	—	4,056	783
Carruthers	—	2,746	908
Celtic	—	1,120	414
Cold Lake	—	702	—
Lashburn	—	452	188
Marsden	—	1,330	—
Neilburg	—	712	459
Poundmaker	—	396	1,049
Seal	—	549	—
Silverdale	—	2,820	528
Tangleflags	—	3,492	1,384
Other minor properties	—	2,895	1,778
Bon Accord	289	—	5,755
Darwin/Nina	—	—	3,909
Goodfish	—	—	6,383
Hamburg/Chinchaga	44	—	3,267
Leahurst	20	—	4,957
Red Earth	856	—	43
Richdale / Sedalia	21	—	9,350
Stoddart	1,714	—	11,776
Tangent	—	—	1,555
Turin	705	—	1,868
Viking	—	—	1,659
Other minor properties	190	—	2,402
Total	3,839	21,270	60,415

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2005:

	Costs Incurred $ Million
Property acquisition costs:	
Proved properties (1)	21.9
Unproved properties	7.1
Development Costs (2)	6.6
Exploration Costs (3)	116.8
Total	152.4

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 2005 exploration 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, 2005.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	445	335.1	354	299.8	437	348.0	296	223.6
British Columbia	39	38.2	35	34.5	26	23.8	12	8.8
Saskatchewan	934	863.6	785	760.6	35	32.1	40	37.3
Total	1,418	1,236.9	1,174	1,094.9	498	403.9	348	269.7

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2005.

	Undeveloped Acres	
	Gross	Net
Alberta	688,673	513,138
British Columbia	112,115	86,055
Saskatchewan	151,225	140,303
Total	952,013	739,496

We expect that rights to explore, develop and exploit approximately 123,000 net acres of our undeveloped land holdings may expire on or before December 31, 2006. There are no material drilling commitments associated with the land holdings expiring by December 31, 2006.

Forward Contracts

For details of our material commitment to sell natural gas and crude oil which were outstanding at December 31, 2005, see Notes 17 and 18 to the Consolidated Financial Statements on page 62 and 63 of our 2005 Annual Report which are incorporated herein by reference.

Additional Information Concerning Abandonment and Reclamation Costs

The following table set 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.

	Abandonment and Reclamation Costs escalated at 2.5 % for the years 2006 to 2008, and 1.5% thereafter Undiscounted ($ Million)	Abandonment and Reclamation Costs escalated at 2.5 % for the years 2006 to 2008, and 1.5% thereafter Discounted at 10%% ($ Million)
Total as at December 31, 2005	217.6	23.7
Anticipated to be paid in 2006	3.2	3.0
Anticipated to be paid in 2007	2.3	2.1
Anticipated to be paid in 2008	2.3	2.1

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 it 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 Sproule estimated we will incur reclamation and abandonment costs is 1,806 wells. This estimate includes all proved producing wells as well as proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2005. 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 the wells not assigned reserves by Sproule, pipelines and facility reclamation costs, net of salvage, which was estimated to be $146.4 million ($32.4 million discounted at 10%), was not deducted in estimating future net revenue.

Tax Horizon

We are classified as a unit trust for income tax purposes, and are taxable on income not distributed to Unitholders. We have, and we expect to continue, to allocate all of our taxable income to Unitholders. Accordingly, no provision for income taxes is required at the Trust level and the information for the most recent oil and gas reserves has been presented on a pre-tax basis.

Capital Expenditures

The following table summarizes capital expenditures related to our activities for the year ended December 31, 2005:

Expenditure	($ 000s)
Land	7,126
Seismic	4,949
Drilling and completion	90,180
Equipment	23,611
Other	4,626
Total exploration and development	130,492
Property acquisitions	70,986
Property dispositions	(49,029)
Net capital expenditures	152,449

Exploration and Development Activities

Approximately 20% of our annual exploration and development budget is 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, 2005.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Oil	14	14.0	50	46.4
Natural Gas	7	3.8	34	30.6
Evaluation	4	4.0	—	—
Dry	3	3.0	6	5.5
Total	28	24.8	90	82.5

Production Estimates

The following table sets out the volume of our production estimated for the year ending December 31, 2006 which is reflected in the estimate of future net revenue disclosed in the tables contained under "- *Disclosure of Reserves Data*".

	Light and Medium Oil (Bbl/d)	Heavy Oil (Bbl/d)	Natural Gas (MMcf/d)	Natural Gas Liquids (Bbl/d)	BOE (Boe/d)
2006	2,200	21,000	61.2	1,600	35,000

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

Production History

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

	Quarter Ended 2005				Quarter Ended 2004			
	Dec. 31	Sept. 30	Jun. 30	Mar. 31	Dec. 31	Sept. 30	Jun. 30	Mar. 31
Average Daily Production								
Light Oil and NGL (Bbl/d)	4,022	4,063	3,404	3,876	2,786	1,890	1,952	2,058
Heavy Oil (Bbl/d)	24,051	20,061	19,653	21,279	22,490	22,083	22,927	23,322
Gas (Mmcf/d)	58.9	63.9	59.3	59.5	55.5	50.9	57.2	56.0
Combined (Boe/d)	37,895	34,780	32,937	35,068	34,525	32,454	34,411	34,709
Average Price Received								
Light Oil and NGL ($/Bbl)	55.48	59.24	53.06	46.69	50.46	52.63	47.55	43.50
Heavy Oil ($/Bbl)	37.75	39.64	30.22	27.38	17.95	22.48	21.42	21.81
Gas ($/Mcf)	10.69	8.39	7.08	6.69	6.60	6.16	6.61	6.43
Combined ($/Boe)	46.48	42.92	36.26	33.10	26.38	28.04	27.92	27.63
Royalties Paid								
Light Oil and NGL ($/Bbl)	9.04	8.53	8.51	6.39	8.00	6.68	6.36	6.02
Heavy Oil ($/Bbl)	4.43	6.83	3.87	3.48	4.22	5.09	3.43	3.39
Gas ($/Mcf)	2.60	1.17	1.09	1.43	1.29	1.20	1.51	1.38

Combined ($/Boe)	7.81	7.09	5.15	5.25	5.47	5.73	5.15	4.87
Production Costs								
Light Oil and NGL ($/Bbl)	6.28	10.40	9.12	10.53	8.57	11.67	9.97	8.35
Heavy Oil ($/Bbl)	11.00	9.49	8.88	8.59	8.61	7.93	7.28	7.51
Gas ($/Mcf)	1.22	1.05	1.02	1.02	0.83	0.87	0.82	0.77
Combined ($/Boe)	9.55	8.61	8.07	8.11	7.63	7.43	6.78	6.78

Transportation								
Light Oil and NGL ($/Bbl)	0.94	0.84	1.55	1.38	0.56	0.97	1.26	1.03
Heavy Oil ($/Bbl)	2.19	2.28	2.48	2.20	1.71	1.76	1.65	1.79
Gas ($/Mcf)	0.14	0.14	0.14	0.14	0.17	0.18	0.19	0.19
Combined ($/Boe)	1.71	1.67	1.89	1.73	1.43	1.53	1.48	1.56
Netback Received								
Light Oil and NGL ($/Bbl)	39.22	39.47	33.88	28.39	33.33	33.31	29.96	28.10
Heavy Oil ($/Bbl)	20.13	21.04	14.99	13.11	3.41	7.70	9.06	9.12
Gas ($/Mcf)	6.73	6.03	4.83	4.10	4.31	3.91	4.09	4.09
Combined ($/Boe)	27.41	25.55	21.15	18.01	11.85	13.35	14.51	14.42

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 60% 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.

The integration and application of these strategies resulted in an average realized price of $8.22 per Mcf in 2005 compared to $6.46 per Mcf in 2004.

For 2006, Baytex has entered into several physical forward sales contracts. These agreements have locked in seasonal natural gas prices over the year at prices above the current forward strip.

Oil and Liquids

Benchmark WTI prices began the year around US$42.00 per bbl, climbed to an all-time high of US$69.81 per bbl on August 30th, and ended the year over US$61 per bbl. The average WTI price for 2005 was US$56.56 per bbl, an increase of 37 percent from US$41.40 in 2004.

Baytex's light oil and natural gas liquids prices averaged $53.84 per bbl before hedging in 2005 compared to $48.64 in 2004. Our heavy oil prices averaged $37.38 per bbl in 2005, compared to $30.32 in 2004.

In October 2002, Baytex signed a five-year crude oil supply agreement with Frontier Oil and Refining Company (" **Frontier**") of Houston, Texas. The agreement calls for Baytex to deliver 20,000 bbl/d of Lloyd Blend ("**LLB**") quality crude at Hardisty, Alberta through the Express Pipeline to Guernsey, Wyoming. The blended crude is comprised of approximately 16,000 barrels of Baytex production and 4,000 bbl/d of diluent. Prices are fixed at 71 percent of WTI or a 29 percent LLB differential which represents the long-term average differential since 1986. This contract significantly reduces the volatility of Baytex's cash flow from its heavy oil operations.

Going forward, 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 2006 on 8,000 bbls/d, at a weighted average price from US$55 to US$84.39 per bbl and for 5,000 bbls/d for 2007 at weighted average prices from US$55 to US$83.69 per bbl.

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 must 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 termination or winding-up of the Trust. 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 "*Redemption Right*") 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 the value of us. 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 the Trust 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. See "*Additional Information Respecting Baytex Energy Ltd. — Share Capital*" 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 by us at a price of $1,050 per 7.50% Convertible Debenture after February 1, 2007 and on or before February 1, 2008 and at a price of $1.025 per 7.50% Convertible Debenture after February 1, 2008 and before maturity on June 30, 2009, 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 termination of the Trust 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 30% to 40% of cash available for distribution for capital expenditures. Depending upon commodity prices, 30% to 40% 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% 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 15, 2006.

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

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% 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% 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% 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 28, 2006, approximately 32% 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 "*Amendments to the Trust Indenture*"), 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% 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 5% 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. The year end of the Trust 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% 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 Trust. 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% of the outstanding Trust Units; (b) a quorum of 50% 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 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
Raymond T. Chan Calgary, Alberta	President, Chief Executive Officer and Director	President and Chief Executive Officer of Baytex since September 2003; prior thereto, Senior Vice President and Chief Financial Officer of Baytex.
John A. Brussa (2) (3) (5) Calgary, Alberta	Director	Partner, Burnet, Duckworth & Palmer LLP (a law firm).
W.A. Blake Cassidy (1) Calgary, Alberta	Director	Retired banker.
Edward Chwyl (2) (3) 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) Calgary, Alberta	Director	Independent businessman since June 2003; prior thereto Senior Managing Director of Raymond James Ltd. (an investment banking firm) and predecessor companies.
R.E.T. (Rusty) Goepel (1) Vancouver, B.C.	Director	Senior Vice President of Raymond James Ltd. and predecessor companies.
Dale O. Shwed (3) (6) 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.
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 from 2001.
Randal J. Best Calgary, Alberta	Vice President, Corporate Development	Vice President, Corporate Development of Baytex since September 2003; prior thereto Managing Director of Waterous Securities Inc. (a private investment and merchant bank).

Ralph W. Gibson Calgary, Alberta	Vice President, Marketing	Vice President, Marketing of Baytex since September 2001; prior thereto Vice President, Crude Oil of Canpet Energy Group Inc. (a private crude oil and liquids trading company).

Name and Municipality Of Residence	Position with Baytex	Principal Occupation
Anthony W. Marino Calgary, Alberta	Chief Operating Officer	Chief Operating Officer of Baytex since November 2004; prior thereto President and Chief Executive Officer of Dominion Exploration Canada Ltd. from October 2002 (a private oil and gas company); prior thereto Vice President, Engineering of Dominion Exploration & Production Inc. from January 2002; prior thereto Team Leader, Jonah/Pinedale asset area of AEC Oil & Gas (USA) Inc. (a subsidiary of a public oil and gas company).
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) 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).
(5) 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.
(6) 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 28, 2006, the directors and executive officers of Baytex, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 641,407 Trust Units, or approximately 0.93% of the issued and outstanding Trust Units. In addition, as at February 28, 2006, the directors and executive officers of Baytex, as a group, beneficially owned, directly or indirectly, exercise control or direction over 455,129 Exchangeable Shares or approximately 29% of the issued and outstanding Exchangeable Shares. No Convertible Debentures were owned by this same group.

Corporate Cease Trade Orders or Bankruptcies

Except as set forth above, in the ten years preceding the date of this Annual Information Form, none of the directors or executive officers of Baytex are or have been a director or executive officer of any other company that, while acting in such capacity:

(b) was the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days;

(c) was subject to an event that resulted, after the director or executive officer ceased to be a director or executive officer, in the company being the subject of a cease trade or similar order or an order that denied the relevant company access to any exemption under securities legislation for a period of more than 30 consecutive days; or

(d) within a year of that person ceasing to act as director or executive officer, became bankrupt, made a proposal under any legislation relating to bankruptcy and 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.

Penalties or Sanctions

No director or officer of Baytex has been subject to any penalties or sanctions under 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.

Personal Bankruptcies

No director or officer of Baytex has in the ten years preceding the date of this Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold their assets.

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 the Trust or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Baytex and the Trust. 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, 2005, Baytex employed 106 head office employees and 23 field office employees.

AUDIT COMMITTEE

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. W.A. Blake Cassidy and Mr. R.E.T. (Rusty) Goepel, each of whom are 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. and predecessor companies.
W.A. Blake Cassidy	Yes	Yes	Retired banker.
R.E.T. (Rusty) Goepel	Yes	Yes	Senior Vice President, Raymond James Ltd. and predecessor companies.

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 2005 and 2004:

	Aggregate fees billed	
	2005	2004
	($000s)	
Audit fees	207	109
Audit-related fees	143	146
Tax fees	42	184
All other fees	44	69
	436	508

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.

Audit-Related Fees. Audit-related services included audit of certain subsidiaries and financial aspects of us.

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

All Other Fees. Other services provided by our external auditor other than audit, audit-related and tax services.

BAYTEX SHARE CAPITAL

Baytex is authorized to issue an unlimited number of common shares and an unlimited number of Exchangeable Shares. As of February 28, 2006, there were 1,594,733 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, 2005, 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 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* ". 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* ".

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% 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* ".

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% 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 above.

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 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 Trustee. As soon as practicable thereafter, the 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:

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

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

(e) 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% 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		Volume Traded
	High ($)	Low ($)	
2003	10.89	9.19	40,973,662
2004	14.00	9.78	93,252,808
2005			
January	13.26	12.42	6,261,488
February	15.07	13.25	11,885,861
March	15.70	13.59	8,262,784
April	15.20	13.32	5,899,560
May	14.06	12.71	6,510,234
June	13.89	12.99	4,993,412
July	15.35	13.45	5,666,105
August	16.49	15.26	6,526,948
September	18.60	15.90	9,940,473
October	18.78	14.13	10,129,669
November	17.74	15.10	5,777,737
December	18.10	16.70	5,627,001
2006			
January	20.69	17.35	9,144,637
February	20.29	16.81	6,959,795

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		Volume Traded
	High ($)	Low ($)	
2005			
June	104.00	99.50	153,890
July	106.50	103.00	68,065
August	112.00	104.85	116,690
September	126.00	108.00	177,560
October	127.00	101.50	139,470
November	120.00	104.50	48,020
December	122.00	114.00	63,280
2006			
January	139.35	117.35	135,685
February	137.35	114.83	62,890

RATINGS

DBRS has assigned a stability rating of STA-6 (high) to the Trust. 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 the Trust, 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.

Baytex has been assigned a senior implied rating of B1 and an issuer rating of B2, 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 Caa. 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.

The Trust has been assigned a long-term corporate credit rating of B+/Negative 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). A negative outlook means that a rating may be lowered.

The stability and credit ratings accorded to Baytex and the Trust by DBRS, Moody's and S&P are not recommendations to purchase, hold or sell any securities of the Trust 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

There are no outstanding legal proceedings involving claims for damages, exclusive of interest and costs, in excess of ten percent (10%) of our current assets, to which we are party or of which any of our properties are subject, nor are there any such proceedings known to be contemplated.

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 more than 10% 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 the Trust's last completed financial year which has materially affected, or would materially affect us.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our Independent Registered Chartered Accountants are Deloitte & Touche LLP, Chartered Accountants, Calgary, 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 statement, report or valuation 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 statement, report or valuation prepared by it, at any time thereafter or to be received by them.

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

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;

(d) the indenture creating the Convertible Debentures; and

(e) our trust unit incentive plan.

Copies of each of these documents have been filed on SEDAR at *www.sedar.com*.

INDUSTRY CONDITIONS

The oil and 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

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

Pricing and Marketing - - Natural Gas

In Canada, the price of natural gas sold 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 criteria prescribed by the NEB and the government of Canada. Natural gas exports for a term of two years or less or for a term of between 2 and 20 years (in quantities of not more than 30,000 m3 /d) may be made pursuant to an NEB order, or, in the case of exports for a longer duration (to a maximum of 25 years) or a larger quantity, pursuant to an NEB export license and Governor in Council approval.

The governments of Alberta, British Columbia and Saskatchewan also regulate the removal of natural gas 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 limits the ability to produce and to market natural gas production. The pro-rating of capacity on the inter-provincial pipeline systems also continues to affect the ability to export oil.

The North American Free Trade Agreement

On January 1, 1994, the North American Free Trade Agreement (" **NAFTA**") among the governments of Canada, the U.S.and Mexico became effective. The NAFTA carries forward most of the material energy terms contained in the Canada-U.S. Free Trade Agreement. In the context of energy resources, Canada continues to remain free to determine whether exports to the U.S. or Mexico will be allowed, provided that any export restrictions are justified under certain provisions of the General Agreement on Tariffs and Trade, and further 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 or in such other representative period as the parties may agree), (ii) impose an export price higher than the domestic price subject to an exception with respect to certain measures which only restrict the volume of exports, and (iii) disrupt normal channels of supply. All three 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.

The NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector 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 that govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil, natural gas, natural gas liquids and sulphur 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 also 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, and 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.

From time to time the governments of Canada and the western Canadian provinces have established incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced recovery projects, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow 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 allow such incentive programs to expire without renewal, and consequently few such incentive programs are currently operative.

On March 3, 2003 the Department of Finance (Canada) released a technical paper entitled "Improving the Income Taxation of the Resource Sector in Canada" (the "**Technical Paper**"). In November, 2003 the Tax Act was amended to provide the following initiatives applicable to the oil and gas industry to be phased in over a five year period: (i) a reduction of the federal statutory corporate income tax rate on income earned from resource activities from 28% to 21%, beginning with a one percentage point reduction effective January 1, 2003, and (ii) a deduction for federal income tax purposes of actual provincial and other Crown royalties and mining taxes paid and the elimination of the 25% resource allowance. In addition, the percentage of ARTC that we will be required to include in federal taxable income will be 12.5% in 2004; 17.5% in 2005; 32.5% in 2006; 50% in 2007; 60% in 2008; 70% in 2009; 80% in 2010; 90% in 2011, and 100% in 2012 and beyond.

Alberta

Regulations made pursuant to the *Mines and Minerals Act* (Alberta) provide various incentives for exploring and developing oil reserves in Alberta. Oil produced from horizontal extensions commenced at least 5 years after the well was originally spudded may also qualify for a royalty reduction. A 24-month, 8,000 m(3) exemption is available to production from a reactivated well that has not produced for: (i) a 12-month period, if resuming production in October, November or December of 1992 or January, 1993; or (ii) a 24 month period, if resuming production in February 1993 or later. As well, oil production from eligible new field and new pool wildcat wells and deeper pool test wells spudded or deepened after September 30, 1992 is entitled to a 12-month royalty exemption (to a maximum of $ 1 million). Oil produced from low productivity wells, enhanced recovery schemes (such as injection wells) and experimental projects is also subject to royalty reductions.

The Alberta government has also introduced a Third Tier Royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 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%.

In Alberta, 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 gas, and between 15% and 35%, in the case of old gas, depending upon a prescribed or corporate average reference price. Natural gas produced from qualifying exploratory natural gas wells spudded or deepened after July 31, 1985 and before June 1, 1988 continues to be eligible for a royalty exemption for a period of 12 months, or such later time that the value of the exempted royalty quantity equals a prescribed maximum amount. Natural gas produced from qualifying intervals in eligible natural 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, 2007, which, among other things, determines the Crown's share of crude and processed oil sands products.

In Alberta, a producer of oil or natural gas is entitled to a credit on qualified oil and natural gas production against the royalties payable to the Crown by virtue of the ARTC program. The ARTC rate is based on a price-sensitive formula, and the ARTC rate currently varies between 75% for prices for oil at or below $ 100 per cubic metre and 25% for prices above $ 210 per cubic metre. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties. The ARTC rate is currently applied to a maximum of $ 2,000,000 of Alberta Crown royalties payable for each producer or associated group of producers. Crown royalties on production from producing properties acquired from corporations claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the applicable government department for the previous quarterly period.

On December 22, 1997, the Alberta government announced that it would conduct a review of the ARTC program with the objective of setting out better targeted objectives for a smaller program and to deal with administrative difficulties. On August 30, 1999, the Alberta government announced that it would not be reducing the size of the program, but that it would introduce new rules to reduce the number of persons who

qualify for the program. The new rules will preclude companies that pay less than $ 10,000 in royalties per year and non-corporate entities from qualifying from the program.

British Columbia

Producers of oil and natural gas in British Columbia are required to pay annual rental payments in respect of Crown leases and royalties and freehold production taxes in respect of oil and gas produced from Crown and freehold lands, respectively. The amount payable as a royalty in respect of oil depends on the 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). Oil produced from newly discovered pools may be exempt from the payment of a royalty for the first 36 months of production. The royalty payable on natural gas is determined by a sliding scale based on a reference price, which is the greater of the amount obtained by the producer, and a prescribed minimum price. 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.

Environmental Regulation

The oil and natural gas industry is subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and gas industry operations and can affect the location and operation of wells and facilities and the extent to which exploration and development is permitted. In addition, legislation requires that well and facilities sites be abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders.

Environmental legislation in the Province of Alberta has been consolidated into the *Environmental Protection and Enhancement Act* (Alberta) (the "**AEPEA**"), which came into force on September 1, 1993 and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The AEPEA and OGCA impose stricter environmental standards, require more stringent compliance, reporting and monitoring obligations and significantly increase penalties. We 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 AEPEA 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.

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 and review process.

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. In April, 2005, Environment Canada released "Project Green", a working paper giving early indications of how implementation was to be achieved. Large Final Emitters ("**LFEs**"), being 700 of Canada's largest emitters, will receive a specific reduction target of 45 mt, and will have the opportunity to purchase domestic offset and technology credits. The exact mechanism for operating in the domestic credit market has yet to be revealed, and the prospect of non-LFE enterprise participating in that market to any great extent is uncertain. Various incentive funds have also been established to provide seed funding for the purchase of experimental technologies, encourage investment in alternative energy sources, and acquire credits from the domestic and international markets for re-sale to Canadian enterprise.

Environment Canada, in August, 2005, released consultation papers for the management of a system of greenhouse gas offsets in the form of tradable and bankable credits. The credits are created by enterprise, individuals, or municipal government through the implementation of projects

registered with the to-be-created offset authority. Standards for quantifying greenhouse gas reductions were also proposed in the consultation paper.

We are committed to meeting our responsibilities to protect the environment wherever we operate and anticipate making increased, although not material, expenditures of both a capital and expense nature as a result of increasingly stringent laws relating to the protection of the environment.

All government regulations and procedures will be followed in strict adherence to the law. We believe in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at *www.sedar.com* and on our website at *www.baytexenergy.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 is contained in our Information Circular – Proxy Statement for the annual and special meeting of Unitholders held on May 11, 2005 and will be contained in our 2006 proxy materials relating to our annual Unitholders meeting to be held on May 15, 2006. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2005 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:

Baytex Energy Trust
2200, 205 - 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: (403) 269-4282
Fax: (403) 205-3845
www.baytex.ab.ca

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Baytex, on behalf of the Trust, are responsible for the preparation and disclosure of information with respect to the oil and gas activities of Baytex in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using constant prices and costs; and

(ii) the related estimated future net revenue.

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 the 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 the Baytex, on behalf of the Trust, has reviewed Baytex's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Audit Committee, approved

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of 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.

(signed) "*Raymond T. Chan*"
Raymond T. Chan
President and Chief Executive Officer

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

(signed) "*Dale O. Shwed*"
Dale O. Shwed
Director

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

February 14, 2006

APPENDIX B

REPORT ON RESERVES DATA

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

1. We have evaluated the reserves data of the Trust as at December 31, 2005. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2005 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas and proved plus probable reserves estimated as at December 31, 2005 using constant prices and costs; and

   (ii) the related estimated future net revenue.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Trust evaluated by us for the year ended December 31, 2005, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to Baytex's Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of [Audit/ Evaluation/ Review] Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) ($ Million)			
			Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	February 24, 2006	Canada	—	1,784.7	—	1,784.7

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. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

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

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

(signed) "Sproule Associates Limited"
Calgary, Alberta
February 24, 2006

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.

Exhibit 99.2

Consolidated Financial Statements of

BAYTEX ENERGY TRUST

December 31, 2005

Management's Report

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

/s/ Raymond T. Chan	/s/ W. Derek Aylesworth
Raymond T. Chan, CA	W. Derek Aylesworth, CA
President and Chief Executive Officer	*Chief Financial Officer*
Baytex Energy Ltd.	Baytex Energy Ltd.
March 7, 2006	

Report of Independent Registered Chartered Accountants
To the Board of Directors of Baytex Energy Ltd. and Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2005 and 2004 and the consolidated statements of operations and accumulated income (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2005 and 2004 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust's internal control over financial reporting. Accordingly, we express no such opinion.

On March 7, 2006, we reported separately to the Unitholders of Baytex Energy Trust on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which excluded Note 19, Differences Between Canadian and United States Generally Accepted Accounting Principles.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

Calgary, Alberta, Canada

March 7, 2006

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there has been a restatement of the financial statements as described in Notes 3 and 19 to the financial statements that have a material effect on the Trust's consolidated financial statements. Our report to the Unitholders, dated March 7, 2006 is expressed in accordance with Canadian reporting standards which do not require a reference to such conditions and events in the auditors' report when the change is properly accounted for and adequately disclosed in the financial statements.

(signed) "Deloitte & Touche LLP"
Independent Registered Chartered Accountants

Calgary, Alberta, Canada

March 7, 2006

Baytex Energy Trust
Consolidated Balance Sheets
As at December 31, 2005 and 2004
(thousands)

	2005	2004 (restated – note 3)
ASSETS		
Current assets		
Accounts receivable	**$ 73,869**	$ 41,154
Crude oil inventory	**9,984**	7,299
Financial derivative contracts (note 17)	**5,183**	—
	89,036	48,453
Deferred charges and other assets	**9,038**	6,491
Petroleum and natural gas properties (note 5)	**969,738**	1,009,933
Goodwill (note 4)	**37,755**	39,259
	$ 1,105,567	$ 1,104,136
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**$ 89,966**	$ 72,976
Distributions payable to unitholders	**10,393**	9,981
Bank loan (note 6)	**123,588**	161,444
Financial derivative contracts (note 17)	**—**	9,513
	223,947	253,914
Long-term debt (note 7)	**209,799**	216,583
Convertible debentures (note 8)	**73,766**	—
Asset retirement obligation (note 9)	**33,010**	73,297
Deferred obligations (note 18)	**4,558**	—
Future income taxes (note 14)	**159,745**	164,909
	704,825	708,703
Non-controlling interest (note 11)	**12,810**	12,936
UNITHOLDERS' EQUITY		
Unitholders' capital (note 10)	**555,020**	515,663
Conversion feature of debentures (note 8)	**3,698**	—
Contributed surplus	**10,332**	6,287
Accumulated distributions	**(267,986)**	(146,445)
Accumulated income	**86,868**	6,992
	387,932	382,497
	$ 1,105,567	$ 1,104,136

Commitments and contingencies (note 18)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

/s/ Naveen Dargan	/s/ W. A. Blake Cassidy
Naveen Dargan	**W. A. Blake Cassidy**
Director	***Director***
Baytex Energy Ltd.	Baytex Energy Ltd.

Consolidated Statements of Operations and Accumulated Income (Deficit)
Years Ended December 31, 2005 and 2004
(thousands, except per unit data)

	2005	2004 (restated — note 3)
Revenue		
Petroleum and natural gas sales	**$ 546,940**	$ 420,400
Royalties	**(81,898)**	(65,988)
Realized loss on financial derivatives	**(48,462)**	(78,124)
Unrealized gain on financial derivatives	**14,696**	597
	431,276	276,885
Expenses		
Operating	**110,648**	89,078
Transportation	**22,399**	18,714
General and administrative	**16,010**	15,243
Unit based compensation (note 12)	**5,346**	4,646
Interest (note 7)	**33,124**	19,412
Foreign exchange gain (note 7)	**(6,784)**	(15,979)
Depletion, depreciation and accretion	**167,135**	160,808
	347,878	291,922
Income (loss) before income taxes and non-controlling interest	**83,398**	(15,037)
Income taxes (recovery) (note 14)		
Current	**8,747**	9,000
Future	**(7,074)**	(41,237)
	1,673	(32,237)
Income before non-controlling interest	**81,725**	17,200
Non-controlling interest (note 11)	**(1,849)**	(436)
Net income	**79,876**	16,764
Accumulated income (deficit), beginning of year, as previously reported	**5,694**	(8,069)
Accounting policy change for Unit based compensation (note 3)	**1,298**	(1,703)
Accumulated income (deficit), beginning of year, as restated	**6,992**	(9,772)
Accumulated income, end of year	**$ 86,868**	$ 6,992
Net income per trust unit (note 13)		
Basic	**$ 1.19**	$ 0.27
Diluted	**$ 1.15**	$ 0.26

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
Years Ended December 31, 2005 and 2004
(thousands)

	2005	2004 (restated – note 3)
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income	**$ 79,876**	$ 16,764
Items not affecting cash:		
Unit based compensation (note 12)	**5,346**	4,646
Amortization of deferred charges	**1,492**	11,171
Unrealized foreign exchange gain	**(6,784)**	(15,979)
Depletion, depreciation and accretion	**167,135**	160,808
Accretion on debentures (note 8)	**321**	—
Unrealized gain on financial derivatives (note 17)	**(14,696)**	(597)
Future income taxes (recovery)	**(7,074)**	(41,237)
Non-controlling interest (note 11)	**1,849**	436
	227,465	136,012
Change in non-cash working capital (note 15)	**(20,212)**	3,589
Asset retirement expenditures	**(1,637)**	(2,739)
Decrease in deferred charges and other assets	**(977)**	212
	204,639	137,074

Financing activities		
Issuance of convertible debentures (note 8)	**100,000**	—
Convertible debentures issue costs (note 8)	**(4,250)**	—
Increase (decrease) in bank loan	**(37,856)**	161,444
Issue of trust units (note 10)	**2,916**	44,505
Payments of distributions	**(114,221)**	(112,074)
	(53,411)	93,875
Investing activities		
Petroleum and natural gas property expenditures	**(201,478)**	(184,065)
Corporate acquisition (note 4)	**—**	(111,042)
Proceeds on disposal of petroleum and natural gas properties	**49,029**	14,441
Change in non-cash working capital (note 15)	**1,221**	(4,014)
	(151,228)	(284,680)
Change in cash and short-term investments during the year	**—**	(53,731)
Cash and short-term investments, beginning of year	**—**	53,731
Cash and short-term investments, end of year	**$ —**	$ —

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Years Ended December 31, 2005 and 2004
(all tabular amounts in thousands, except per unit amounts)

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, Baytex Energy Ltd. (the "Company") is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles as described in note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenues and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Cash and Short-term Investments

Cash and short-term investments include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the “ceiling test”). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the reporting entity. If the fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

Convertible Unsecured Subordinated Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders’ equity. Issue costs will be amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders’ equity will be reclassified to unitholders’ capital along with the principal amounts converted.

Asset Retirement Obligation

The Trust recognizes a liability at discounted fair value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period the actual costs are incurred.

Joint Interests

A portion of the Trust’s exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust’s proportionate interest in such activities.

Foreign Currency Translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Deferred Charges and Other Assets

Financing costs related to the exchange of the senior subordinated notes have been deferred and are amortized over the term of the notes on a straight-line basis.

Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policies included the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. Financial derivative contracts used as hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with financial derivative contracts. Financial derivative contracts that do not qualify for hedge accounting are recognized in the balance sheet and measured at fair value, with changes in fair value reported separately in the statement of operations as income or expense.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 12. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Non-controlling Interest

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised or exchangeable shares were converted or convertible debentures were fully converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during the period.

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3. CHANGE IN ACCOUNTING POLICY

Unit-Based Compensation

Until July 1, 2005, the Trust accounted for unit based compensation based on the intrinsic value of the grants at each reporting date. Effective July 1, 2005, on a prospective basis, the Trust began valuing unit rights using the fair value based method. In the fourth quarter of 2005, the trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

As a result of retroactively adopting the fair value method of estimating compensation expense, net income for the comparative year ended

December 31, 2004 was increased by $3.0 million, net of non-controlling interest of $0.09 million. The opening 2004 accumulated deficit was increased by $1.7 million, net of non-controlling interest of $0.1 million. There was also a decrease in unitholders' capital of $0.07 million during 2004 relating to the transfer of value from contributed surplus on exercise of unit option rights. There was no impact on cash flow as a result of adopting this policy (note 12).

4. Corporate Acquisition

Effective September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta. The transaction was accounted for using the purchase method of accounting. The estimated fair value of the assets acquired and liabilities assumed at the date of acquisition is summarized below. Subsequent to the acquisition, the private company was amalgamated with the Company.

Petroleum and natural gas properties	$ 109,777
Goodwill	37,755
Working capital	2,951
Capital lease obligation	(777)
Asset retirement obligation	(8,435)
Future income taxes	(30,229)
Total net assets acquired	$ 111,042
Financed by:	
Cash	$ 110,822
Costs associated with acquisition	220
Total purchase price	$ 111,042

Goodwill of $37.8 million was determined based on the excess of the total consideration paid less the fair value assigned to the identifiable assets and liabilities including the future income tax liability.

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31, 2005	2004
Petroleum and natural gas properties	**$ 2,461,045**	$ 2,342,514
Accumulated depletion and depreciation	**(1,491,307)**	(1,332,581)
	$ 969,738	$ 1,009,933

In calculating the depletion and depreciation provision for 2005, $46.6 million (2004 - $61.7 million) of costs relating to undeveloped properties and materials were excluded from costs subject to depletion and depreciation. No general and administrative expenses have been capitalized since the inception of operations as a trust effective September 2, 2003.

The petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2005 using the following benchmark reference prices for the years 2006 to 2010 adjusted for commodity differentials specific to the Trust (note 18):

	2006	2007	2008	2009	2010
WTI (US$/bbl)	60.81	61.61	54.60	50.19	47.76
AECO (CDN$/mmbtu)	11.58	10.84	8.95	7.87	7.57

The prices and costs subsequent to 2010 have been adjusted for inflation at an annual rate of 1.5 percent. Based on the ceiling test calculation, the Trust's estimated undiscounted future net cash flows associated with the proved reserves plus the cost less impairment of unproved properties exceeded the book value of the petroleum and natural gas properties.

6. BANK CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit (note 18) can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2005 a total of $123.6 million had been drawn under the credit facilities.

7. LONG-TERM DEBT

	As at December 31, 2005	2004
10.5% senior subordinated notes (US$247,000)	**$ 288**	$ 297
9.625% senior subordinated notes (US$179,699,000)	**209,511**	216,286
	$ 209,799	$ 216,583

Senior Subordinated Notes

The Company has US$247,000 senior subordinated notes bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 are unsecured and are subordinate to the Company's bank credit facilities. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

Interest Expense

The Company incurred interest expense on its outstanding debt as follows:

	2005	2004
Bank loan	**$ 8,318**	$ 2,256
Amortization of deferred charges	**1,492**	1,060
Long-term debt	**23,314**	16,096
Total interest	**$ 33,124**	$ 19,412

8. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

On June 6, 2005 the Trust issued $100 million principal amount of 6.5 % convertible unsecured subordinated debentures for net proceeds of $95.8 million. The 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 debentures mature on December 31, 2010 at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. Issue costs are being amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

Debentures issued on June 6, 2005	$ 100,000
Fair value of conversion feature	(4,800)
Conversion of Debentures and amortization of discount	(21,434)
Debentures outstanding December 31, 2005	$ 73,766

9. ASSET RETIREMENT OBLIGATIONS

	As at December 31, 2005	2004
Balance, beginning of the year	**$ 73,297**	$ 55,996
Liabilities incurred	**406**	4,623
Liabilities settled	**(1,637)**	(2,739)
Acquisition of liabilities	**3,410**	12,797
Disposition of liabilities	**(2,117)**	(1,722)
Accretion	**5,762**	4,342
Change in estimate(1)	**(46,111)**	—
Balance, end of the year	**$ 33,010**	$ 73,297

(1) The change in estimate was primarily due to the significant increase in recent and forecasted market price of petroleum and natural gas. Consequentially, the projected economic life of the wells and facilities are extended, resulting in wells and facilities being abandoned and reclaimed further out in the future and thus a lower present value of asset retirement obligations.

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years with the majority of costs incurred between 2044 and 2057. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2005 is $218 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 2.5 percent for the years 2006 to 2008, and 1.5 percent thereafter.

10. UNITHOLDERS' CAPITAL

Trust Units

The Trust is authorized to issue an unlimited number of trust units.

Trust Units	Number of units	Amount (restated - note 3)
Balance December 31, 2003	60,821	$ 449,403

Issued on conversion of Exchangeable Shares	1,994	21,222
Issued on exercise of trust unit rights	113	1,005
Transfer from contributed surplus on exercise of trust unit rights (restated - note 3)	—	402
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	515,663
Issued on conversion of Debentures	1,549	22,859
Issued on conversion of Exchangeable Shares	363	5,373
Issued on exercise of trust unit rights	369	2,916
Transfer from contributed surplus on exercise of trust unit rights	—	1,301
Issued pursuant to distribution reinvestment program	464	6,908
Balance December 31, 2005	69,283	$ 555,020

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95% of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units 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. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

On December 20, 2004, the Trust issued 3,600,000 trust units at $12.80 per unit for gross proceeds of $46.1 million pursuant to a prospectus.

11. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is adjusted monthly based on the cash distribution paid divided by the weighted average trust unit price for the five-day trading period ending on the record date. The exchange ratio at December 31, 2005 was 1.37201 trust units per exchangeable share (2004 - 1.21472 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

Non-controlling Interest	Number of Exchangeable Shares	Amount
Balance December 31, 2003 (restated – note 3)	3,725	$ 25,590
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income	—	436
Balance December 31, 2004 (restated – note 3)	1,876	12,936
Exchanged for trust units	(279)	(1,975)
Non-controlling interest in net income	—	1,849
Balance December 31, 2005	1,597	$ 12,810

As the exchangeable shares are converted to Trust units, the exchange is accounted for as a step-acquisition where Unitholders' capital was increased by the fair value of the Trust units issued. The difference between the fair value of the Trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

12. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the plan is a "rolling" maximum equal to 10% of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding units will result in an increase in the available number of trust units issuable under the plan, and any exercises of incentive rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions.

The Trust recorded compensation expense of $5.3 million for the year ended December 31, 2005 ($4.6 million in 2004) (note 3).

The Trust used the Black-Scholes option-pricing model to calculate the estimated fair value of the outstanding rights. The following assumptions were used to arrive at the estimate of fair values:

	2005	2004
Expected annual right's exercise price reduction	$ 1.80	$ 1.80

Expected volatility	23%	30%
Risk-free interest rate	3.30% - 3.84%	3.59% - 4.31%
Expected life of option (years)	5	5

The number of unit rights issued and exercise prices are detailed below:

	Number of rights	Weighted average exercise price (1)
Balance, December 31, 2003	2,855	$ 10.15
Granted	1,297	$ 11.77
Exercised	(113)	$ 8.87
Cancelled	(502)	$ 9.54
Balance, December 31, 2004	3,537	$ 9.60
Granted	2,451	$ 15.01
Exercised	(369)	$ 7.90
Cancelled	(253)	$ 9.83
Balance, December 31, 2005	5,366	$ 10.88

(1) Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2005:

Range of Exercise Prices	Number Outstanding at December 31, 2005	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2005	Weighted Average Exercise Price
$ 5.41 to $ 8.50	1,959	2.7	$ 6.60	1,136	$ 6.57
$ 8.51 to $ 11.50	1,028	3.8	$ 10.45	323	$ 10.45
$ 11.51 to $ 14.50	472	4.4	$ 12.57	—	—
$ 14.51 to $ 17.68	1,907	4.8	$ 15.08	—	—
$ 5.41 to $ 17.68	5,366	3.8	$ 10.88	1,459	$ 7.43

13. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the year, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	2005	2004
Weighted average number of units outstanding, basic	67,382	62,574
Trust units issuable on conversion of exchangeable shares	2,330	2,635
Dilutive effect of trust unit incentive rights	1,438	473
Trust units issuable on conversion of convertible debentures	2,981	—
Weighted average number of units outstanding, diluted	74,131	65,682

The dilutive effect of trust unit incentive rights above did not include 3.9 million trust unit rights (2004 – 3.1 million) because the respective exercise prices exceeded the average market price of the trust units during the year and the amount of compensation expense attributed to future services was not yet recognized.

14. INCOME TAXES (RECOVERY)

The provision for (recovery of) income taxes has been computed as follows:

	2005	2004 (1) (restated – note 3)
Income (loss) before income taxes and non-controlling interest	$ 83,398	$ (15,037)
Expected income taxes (recovery) at the statutory rate of 40.10% (2004 – 40.57%)	33,443	(6,101)
Increase (decrease) in taxes resulting from:		
Resource allowance	(13,650)	(9,663)
Alberta royalty tax credit	(130)	(203)
Net income of the Trust	(29,415)	(30,097)
Non-taxable portion of foreign exchange gain	(1,360)	(3,241)
Effect of change in tax rate	2,734	(7,438)
Effect of change in opening tax pool balances	851	8,711
Effect of change in valuation allowance	(1,400)	5,194
Unit based compensation	2,143	1,696
Other	(290)	(95)
Large corporation tax and provincial capital tax	8,747	9,000
Provision for (recovery of) income taxes	$ 1,673	$ (32,237)

(1) Certain comparative figures have been reclassified to conform to the current year's presentation.

The components of future income taxes are as follows:

	As at December 31	
	2005	2004
Future income tax liabilities:		
Capital assets	$ 170,008	$ 193,584
Other	13,304	12,853
Future income tax assets:		
Asset retirement obligation	(11,917)	(26,072)
Reorganization costs	(7,212)	(12,206)
Loss carry-forward	(4,438)	(3,250)
Future income taxes	$ 159,745	$ 164,909

15. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

	2005	2004
Current assets	$ (35,401)	$ (6,055)
Current liabilities	16,410	5,630
	$ (18,991)	$ (425)
Changes in non cash working capital related to:		
Operating activities	$ (20,212)	$ 3,589
Investing activities	1,221	(4,014)
	$ (18,991)	$ (425)

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes.

	2005	2004
Interest	$ 29,728	$ 21,096
Current income taxes	$ 8,536	$ 17,485

16. FINANCIAL INSTRUMENTS AND CREDIT RISK

The Trust's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, current liabilities and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction.

The fair values of financial instruments other than bank debt and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank debt approximates its book value as it is at a market rate of interest. At December 31, 2005, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2004 - - 105 percent). The market value of the Trust's convertible debentures at December 31, 2005 was 118 percent in relation to par.

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. The book value of the accounts receivable reflects management's assessment of the associated credit risks.

The Trust is exposed to interest rate risk as a result of its floating rate debts.

17. FINANCIAL DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts.

At December 31, 2005, the Trust had derivative contracts for the following:

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI

FOREIGN CURRENCY

	Period	Amount	Floor	Cap
collar	Calendar 2006	US$3,000,000 per month	CAD$/US $1.1700	CAD$/US $1.2065

INTEREST RATE SWAP

Period	Principal	Rate
November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

Under the CICA guideline for hedge accounting, the Trust's financial derivative contracts for oil collars and foreign currency exchange do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. At December 31, 2005, the Trust recorded an asset of $5.2 million (2004 – a liability of $9.5 million) on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives during 2005 has been recorded as an unrealized gain on non-hedging financial derivatives of $14.7 million (2004 - $0.6 million) in the consolidated statement of operations. The Trust is applying hedge accounting to the interest rate swap and gains and losses are netted against interest expense.

In 2006, the Company entered into derivative contracts for the following:

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2007	2,000 bbl/d	US$55.00 – $83.60	WTI
Price collar	Calendar 2007	3,000 bbl/d	US$55.00 – $83.75	WTI

FOREIGN CURRENCY

	Period	Amount	Floor	Cap
collar	February 1, 2006 to December 31, 2006	US$4,000,000 per month	CAD/US$1.1500	CAD/US$1.1835
collar	January 9, 2006 to December 31, 2006	US$3,000,000 per month	CAD/US$1.1500	CAD/US$1.1780

18. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71% of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

At December 31, 2005, the Trust had entered into natural gas physical sales contracts with third parties as follow:

GAS	Period	Volume	Price
Fixed price	January 1, 2006 to February 28, 2006	3,000 GJ/d	CAD$10.00
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.07
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.20
Fixed price	January 1, 2006 to March 31, 2006	2,000 GJ/d	CAD$10.63
Fixed price	March 1, 2006 to March 31, 2006	3,000 GJ/d	CAD$11.53
Fixed price	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	January 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 - $13.40
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 - $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 – $12.60

At December 31, 2005 the Trust had operating lease and transportation obligations as detailed below:

	Payments Due			
($ thousands)	Total	Within 1 year	1-3 years	4-5 years
Operating leases	8,117	1,621	5,834	662
Transportation agreements	3,446	2,052	1,394	—
Total	11,563	3,673	7,228	662

At December 31, 2005, there are outstanding letters of credit aggregating $7.1 million issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value ($7.8 million) of the original obligation is being drawn down over the life of the obligations which continue until October 2008.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

19. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

Reconciliation of Financial Statements to United States Generally Accepted Accounting Principles

The consolidated financial statements included in the Trust 2005 Annual Report have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"), which in most respects, conform to generally accepted accounting principles in the United States of America ("U.S. GAAP"). The significant differences in those principles, as they apply to the Trust, are as follows:

(a) Under U.S. GAAP, the book value of petroleum and natural gas properties and related facilities, net of future or deferred income taxes, is limited to the present value of after tax future net revenue from proven reserves, discounted at 10 percent, (based on prices and costs at the balance sheet date) plus the lower of cost and fair value of unproven properties.

Under Canadian GAAP the first stage of this "ceiling test" is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the petroleum and natural gas assets are impaired. An impairment loss exists when the book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices.

As a result of applying the U.S. GAAP ceiling test in prior years, the Trust recorded additional depletion of $340.7 million before income tax. Where the amount of a ceiling test write-down under Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation, and accretion will differ in subsequent years.

Effective January 1, 2004, the Trust adopted changes to the Canadian Institute of Chartered Accountants ("CICA") Full Cost Accounting Guideline. Under Canadian GAAP, depletion is calculated by reference to proved reserves estimated using forecast prices and costs. Under U.S. GAAP, depletion charges are calculated by reference to proved reserves estimated using constant prices and costs. The difference in proved reserves has resulted in $14.8 million (2004 - $0.5 million) less depletion recorded under U.S. GAAP.

(b) The Trust Units contain a redemption feature which is required for the Trust to retain its mutual fund trust status for Canadian income tax purposes. The redemption feature of the trust units entitles the holder to redeem the Trust Units. However, the restrictions on redemption are not substantive enough to be accounted for as a component of permanent Unitholders' Equity under U.S. GAAP, in accordance with Emerging Issues Task Force ("EITF") D-98, and the trust units must be presented as Temporary Equity and carried on the consolidated balance sheets at their redemption value.

In applying EITF D-98 the Trust has recorded Temporary Equity in the amount of $1,265.1 million for 2005 and $ 878.8 million for 2004 which represents the estimated redemption value of the Trust Units and the exchangeable shares (which are convertible into trust units) at the balance sheet date. The difference between the Trust's Temporary Equity under U.S. GAAP and Unitholders' Capital under Canadian GAAP is applied to Accumulated Income (Deficit). The adjustments to Accumulated Income (Deficit) are a charge of $386.3 million for 2005 and $176.6 million for 2004. As a result, the Accumulated Income (Deficit) year-end balance is reduced by $868.1 million in 2005 and $481.8 million in 2004.

In compliance with EITF D-98, the Trust also reclassed to Temporary Equity of $26.3 million in 2005 and $7.4 million in 2004 of Contributed Surplus relating to the intrinsic value of Trust Unit Rights outstanding at year-end. As a result, the Trust has retroactively restated contributed surplus on its consolidated balance sheet in 2004.

Under Canadian GAAP, the exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet. Net income under Canadian GAAP has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet.

Under U.S. GAAP, the consolidated balance sheet would not include an amount for non-controlling interest and income would not be reduced. Instead, under U.S. GAAP, the estimated redemption amount of the exchangeable shares at balance sheet date would be included in Temporary Equity on the consolidated balance sheet.

(c) The Trust has a Trust Units Rights Incentive Plan established in 2003. As the execrise price of the unit rights granted under the plan is subject to downward revisions from time to time, the unit rights plan is a variable compensation plan under U.S. GAAP. Accordingly, compensation expense is determined as the excess of the market price over the exercised price at the end of each reporting period and is recognized in income over the vesting period of the rights. The accounting for compensation expense for the unit rights plan results in a difference between Canadian and U.S. GAAP, as the Trust uses the fair value method to account for its unit compensation expense under Canadian GAAP.

The Company had a stock option plan which was terminated in 2003. Until the termination of the stock option plan, the accounting for the stock option plan was done in accordance with FASB Statement of Financial Accounting Standards No. 123, "Accounting for Stock-based Compensation" ("FAS 123"). FAS 123 establishes financial accounting and reporting standards for stock-based employee compensation plans as well as transactions in which an entity issues its equity instruments to acquire goods or services from non-employees. As permitted by the FAS 123, the Trust elected to follow the intrinsic value method of accounting for stock-based compensation arrangements, as provided for in Accounting Principles Board Opinion 25 ("APB 25").

APB 25 also requires recognition of compensation cost with respect to changes in intrinsic value for variable employee stock compensation plans. As a result of the modifications to the terms of employee stock options, the modified options were subject to variable plan accounting, which resulted in a year-to-date cumulative charge of $13.8 million to accumulated income at December 31, 2003 for U.S. GAAP purposes.

(d) On January 1, 2001, the Company adopted Statement of Financial Accounting Standards No. 133, "Accounting for Derivative instruments and Hedging Activities" (FAS 133), as modified by Statement No. 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities". The statement, as amended, establishes accounting and reporting standards requiring that every derivative instrument be

recorded in the balance sheet as either an asset or liability measured at its fair value, and that change in the fair value be recognized currently in income unless specific hedge accounting criteria are met. This statement requires an entity to establish, at the inception of a hedge, the method it will use for assessing the effectiveness of the hedging derivative and the measurement approach for determining the ineffective aspect of the hedge. Those methods must be consistent with the entity's approach to managing risk. At December 31, 2005, the Trust's financial instruments that do not meet the specific hedge accounting under U.S. GAAP has resulted in the recording on the balance sheet, at their fair value, an asset of $5.7 million (2004 – $2.9 million) and a liability of $1.6 million (2004 – nil).

Upon adoption of AcG-13, deferred credits for derivative instruments of $10.1 million were recognized representing the fair market value of derivative financial instruments in place as of January 1, 2004. The deferred charges are amortized over the life of the derivative financial instruments for Canadian GAAP and were equal to the aggregate of U.S. GAAP gains and losses incurred on these instruments, prior to January 1, 2004. During 2004, $10.1 million of the deferred charges was amortized to income under AcG-13. Because this amount was expensed in previous periods for U.S. GAAP, the amount has been reversed in the year ended December 31, 2004 for U.S. GAAP.

(e) Statement of Financial Accounting Standards No. 130 "Comprehensive Income" requires the reporting of comprehensive income in addition to net income. Comprehensive income includes net income plus other comprehensive income. Management believes that it has no other comprehensive income; accordingly comprehensive income is equivalent to net income.

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Years Ended December 31, 2005 and 2004
(all tabular amounts in thousands of Canadian dollars, except per unit amounts)

Consolidated Statements of Operations

The application of U.S. GAAP would have the following effect on net income as reported:

	Years Ended December 31	
	2005	2004 (restated - note 3)
Net income for the year – Canadian GAAP	$ 79,876	$ 16,764
Adjustments:		
Depletion (a)	14,751	527
Non-controlling interest (b)	2,223	436
Compensation expense (c)	(16,581)	(3,090)
Interest rate swaps (d)	2,570	(1,061)
Financial derivative instruments (d)	(1,240)	10,110
Income taxes	(6,449)	(3,886)
Net income for the year – U.S. GAAP	$ 75,150	$ 19,800
Net income per unit – U.S. GAAP		
Basic	$ 1.08	$ 0.30
Diluted	$ 1.06	$ 0.30

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Years Ended December 31, 2005 and 2004
(all tabular amounts in thousands of Canadian dollars, except per unit amounts)

Consolidated Balance Sheets

The application of U.S. GAAP would have the following effect on the Consolidated Balance Sheets as reported:

	December 31, 2005		
	Canadian GAAP as Reported	Increase (Decrease)	U.S. GAAP
Assets:			
Capital assets (a)	$ 969,738	$ (116,594)	$ 853,144
Financial derivative instruments (d)	—	5,737	5,737
Liabilities:			
Financial derivative instruments (d)	—	1,550	1,550
Future income taxes	159,745	(53,224)	106,521
Non-controlling interest (b)	12,810	(12,810)	—
Temporary equity (b)	—	1,291,405	1,291,405
Unitholders' equity:			
Unitholders' capital (b)	555,020	(555,020)	—

Contributed Surplus (b)	10,332	(10,332)	—
Accumulated income (deficit) – see below	86,868	(978,316)	(891,448)

	December 31, 2004 (restated (b))		
	Canadian GAAP as Reported (restated - note 3)	Increase (Decrease)	U.S. GAAP
Assets:			
Capital assets (a)	$ 1,009,933	$ (136,654)	$ 873,279
Financial derivative instruments (d)	—	2,858	2,858
Liabilities:			
Future income taxes	164,909	(61,583)	103,326
Non-controlling interest (b)	12,936	(12,936)	—
Temporary equity (b)	—	886,288	886,288
Unitholders' equity:			
Unitholders' capital (b)	515,663	(515,663)	—
Contributed Surplus (b)	6,287	(6,287)	—
Accumulated income (deficit) – see below	6,992	(587,284)	(580,292)

	December 31,	
	2005	2004 (restated (b))
Accumulated income (deficit) - Canadian GAAP	$ 86,868	$ 6,992
Adjustments to depletion (a)	(147,586)	(162,337)
Compensation expense (c)	(31,699)	(15,117)
Financial derivative instruments (d)	4,188	2,858
Non-controlling interest (b)	1,876	(347)
Change in redemption value of trust units (b)	(868,115)	(481,810)
Adjustments to future income taxes	64,745	71,194
Cumulative effect of change in accounting policy for asset retirement obligation (c)	(1,725)	(1,725)
Accumulated deficit - U.S. GAAP	$ (891,448)	$ (580,292)

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Years Ended December 31, 2005 and 2004
(all tabular amounts in thousands of Canadian dollars, except per unit amounts)

Consolidated Statements of Cash Flow

The application of U.S. GAAP would not have an effect on the operating activities of the consolidated statements of cash flow:

Recent Developments in U.S. Accounting

In February 2006, the Financial Accounting Standards Board ("FASB") issued Statement No. 155, "Accounting for Certain Hybrid Financial Instruments". This is an amendment of FASB Statements No. 133, "Accounting for Derivative Instruments and Hedging Activities", and Statement 140, "Accounting for Transfers and Servicing of financial Assets and Extinguishments of Liabilities". This Statement permits fair value re-measurement for hybrid financial instruments that contain embedded derivatives and further clarifies the definition of embedded derivatives. Statement 155 eliminates the prohibition in Statement 140 on a qualifying special-purpose entity from holding a derivative financial instrument. The Trust has accounted for its convertible debentures in compliance to all applicable derivative accounting guidelines.

In May 2005, the FASB issued Statement No. 154, "Accounting Changes and Error Corrections". This Statement replaces APB Opinion No. 20, Accounting Changes, and FASB Statement No. 3, Reporting Accounting Changes in Interim Financial Statements, and changes the requirements for the accounting and reporting of a change in accounting principle. Opinion 20 previously required that most voluntary changes in accounting principle be recognized by including the cumulative effect of changing to the new accounting principle in net income of the period of the change. This Statement requires retrospective application to prior periods' financial statements unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. The Trust has adopted this standard in the preparation of its consolidated financial statements.

In December 2004, the FASB Issued SFAS No. 123R, "Share Based Payments", which addresses the issue of measuring compensation cost associated with Share Based Payment plans. This statement requires that all such plans, for public entities, be measured at fair value using an option pricing model whereas previously certain plans could be measured using either a fair value method or an intrinsic value method. The revision is intended to increase the consistency and comparability of financial results by only allowing one method of application. This revised standard is effective for the first interim or annual period beginning on or after June 15, 2005 for awards granted on or after the effective date.

Statement 123R also requires liability classified awards to be re-measured to fair value at each balance sheet date until the award is settled. On August 31, 2005, Statement 123R-1 was issued to defer the requirement that a freestanding financial instrument originally subject to 123R becomes subject to the recognition and measurement requirements of other applicable generally accepted accounting principles when the rights conveyed by the instrument to the holder are no longer dependent on the holder being an employee of the entity. On October 18, 2005, Statement 123R-2 was issued to provide further guidance on the application of grant date as defined in FAS 123R. The Trust is currently

assessing the impact of FAS 123R on its consolidated financial statements.

In December 2004, the FASB issued SFAS No. 153, “Exchanges of Nonmonetary Assets” which amends APB Opinion No. 29, “Accounting for Nonmonetary Transactions”. SFAS No. 153 amends Opinion 29 to eliminate the exception for nonmonetary exchanges of similar productive assets and replaces it with a general exception for exchanges of nonmonetary assets that do not have commercial substance. A nonmonetary exchange has commercial substance if the future cash flows of the entity are expected to change significantly as a result of the exchange. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005. The Trust does not expect the adoption of this standard to have any material effect on its consolidated financial statements.

Recent Developments in Canadian Accounting

Financial Instruments In January, 2005 the CICA issued three new standards relating to the reporting of financial instruments in financial statements. These standards introduce new requirements for the recognition and measurement of financial instruments and comprehensive income. Section 3855, “Financial Instruments – Recognition and Measurement” requires that all financial instruments, including derivatives, are to be included on a company’s balance sheet and measured, either at their fair values or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. The standard also provides guidance on when gains and losses as a result of changes in fair values are to be recognized in the income statement.

The issuance of the new Section 3855 will result in amendments to Section 3860 “Financial Instruments – Disclosure and Presentation” to make the scope and definitions consistent with that of the new Section 3855, including expanding the scope to include certain commodity-based contracts, and to update certain disclosures in light of the introduction of Section 3855. Other Handbook Sections have also been amended for conformity with the new standards.

Section 3865 “Hedges”, extends the existing requirements for hedge accounting currently under AcG -13. This new section allows for the optional treatment of accounting for financial instruments that are designated as either fair value hedges, cash flow hedges or hedges of a net investment in a self-sustaining foreign operation. For a fair value hedge, the gain or loss on a derivative hedging item, or the gain or loss on a non-derivative hedging item attributable to the hedged risk, is recognized in net income in the period of change together with the offsetting loss or gain on the hedged item attributable to the hedged risk. The carrying amount of the hedged item is adjusted for the hedged risk. For a cash flow hedge, the effective portion of the hedging item’s gain or loss is initially reported in other comprehensive income and subsequently reclassified to net income when the hedged item affects net income. For a hedge of a net investment in a self-sustaining foreign operation the same accounting is followed as for a cash flow hedge.

A new location for recognizing certain gains and losses – other comprehensive income – has been introduced with the issued of Section 1530, “Comprehensive Income”. An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other Comprehensive Income. This standard requires that a company should present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements. Exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation, previously recognized in a separate component of shareholders’ equity, in accordance with Section 1650, “Foreign Currency Translation”, will now be recognized in a separate component of other comprehensive income.

These three new Handbook Sections are effective date for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust is evaluating the impact the adoption of these new standards will have on its consolidated financial statements.

Non-Monetary Transactions In June 2005, The CICA issued Section 3831 “Non-Monetary Transactions”, which replaces the culmination of earnings test with a commercial substance test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Company does not expect application of this new standard to have a material impact on its consolidated financial statements.

Exhibit 99.3

Management's Discussion and Analysis

The following Management's Discussion and Analysis ("MD&A"), dated March 8, 2006, should be read in conjunction with Baytex Energy Trust's (the "Trust" or "Baytex") audited consolidated financial statements for the fiscal years ended December 31, 2005 and 2004. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netbacks ("netbacks"), finding, development and acquisition costs ("FD&A"), recycle ratio and total capitalization to analyze financial and operating performance. These key performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This discussion and analysis contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning, among other things, future operating results and various components thereof or the economic performance of the Trust. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2005 and 2004, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Readers should not place undue reliance on any such forward-looking statements, which speak only as of the date they were made. The Trust is not obligated to publicly update or revise the forward-looking statements relating to future events or future performance to reflect any change in management's expectations or events.

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, Baytex Energy Ltd. (the "Company") is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

2005 OVERVIEW

On June 6, 2005 the Trust issued $100 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The 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 debentures mature on December 31, 2010 at which time they are due and payable. The net proceeds 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 (13 - 15 API) and 0.9 MMcf/d of natural gas. Production from this acquisition represented approximately 10% of our 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, Baytex's second largest producing area within its heavy oil operations. The expanded Celtic/Tangleflags operating region will improve economies of scale and allow for better control over costs. The acquisition also 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 SAGD (steam assisted gravity drainage) 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. These proceeds were used to repay bank borrowings.

PROPERTY REVIEW

Principal Properties

Baytex's crude oil and natural gas operations are organized into two operating districts - the Heavy Oil District and the Light Oil and Natural Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Baytex has established several geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen)

within each district. Each team has a mandate to apply its specific knowledge and expertise to its operating area. This focused approach aids in the evaluation and execution of exploration, development and acquisition opportunities and improves cost efficiency.

Heavy Oil District

The Heavy Oil District accounts for approximately 60 percent of current production, three quarters of oil-equivalent reserves and one-half of cash flow from operations. Baytex's heavy oil operations consist largely of cold primary production, without the assistance of steam injection. In some cases, 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 low gravity 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. The 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.

In 2005, production in the Heavy Oil District averaged 21,265 bbl/d of heavy oil and 7.5 MMcf/d of natural gas (22,515 boe/d). Baytex drilled 67 gross (65.4 net) wells in the Heavy Oil District resulting in 59 (57.4 net) oil wells, one (1.0 net) gas well, four (4.0 net) stratigraphic test wells, and three (3.0 net) dry and abandoned wells, for a success rate of 96 percent (95 percent net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River/Seal heavy oil sands. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to offsetting the Trust's overall production decline rate. Because of Baytex's large inventory of heavy oil

investment projects, the Trust is able to regulate the timing and level of its capital investment program while generally maintaining production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus on the development of the /Seal field and the newly acquired Celtic property, along with continued drilling and re-completion activity throughout Baytex's Saskatchewan properties. Company net undeveloped lands in this district totaled approximately 313,900 acres at year-end 2005.

Ardmore: 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 2005 was approximately 4,100 bbl/d of oil and 800 Mcf/d of natural gas (4,200 boe/d). Current production is approximately 3,900 bbl/d and 700 Mcf/d of natural gas (4,000 boe/d). Sixteen successful oil wells and no dry holes were drilled in the area during 2005. During 2006, Baytex anticipates drilling eight to ten wells. In 2005, operating expenses were maintained at $5.50/bboe by using a company-owned water disposal facility and continuing to conserve solution gas that is produced in conjunction with the heavy oil. Company net undeveloped lands were 41,800 acres at year-end 2005.

Carruthers: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. A typical vertical oil well will initially produce at 40 bbl/d and provide an ultimate recovery of approximately 60,000 barrels of reserves. During 2005, average production was approximately 2,700 bbl/d of heavy oil and 900 Mcf/d of natural gas (2,900 boe/d). Five successful oil wells were drilled in South Carruthers during 2005. This area represents a very stable production base with continued development drilling expected to total three to five wells annually. Current production is approximately 2,900 bbl/d and 900 Mcf/d of natural gas (3,100 boe/d). Company net undeveloped lands were 12,400 acres at year-end 2005.

Celtic: This producing property was acquired in October 2005, in a transaction which included approximately 1,750 bbl/d of SAGD production. The SAGD production was divested at the end of 2005, leaving Baytex with the cold heavy oil and gas production. At the time of the purchase, cold production rates were approximately 1,600 bbl/d of heavy oil and 0.9 MMcf/d of natural gas. Current production has increased to over 3,000 boe/d. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a huge resource base (455 million barrels of original oil in-place) within multiple prospective horizons. The Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Also like Tangleflags, the heavy oil is relatively gas saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2006, Baytex

expects to drill 30 wells and recomplete 25 to 30 additional wells. In addition, it is anticipated that between 500 and 1,000 Mcf/d of solution gas sales will be added through on-going tie-in projects. Company net undeveloped lands were 7,100 acres at year-end 2005.

Cold Lake: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily generated from the Colony formation. Average oil production was 700 bbl/d for 2005, during which time Baytex drilled two (1.8 net) oil wells and no dry wells. Current production is approximately 670 bbl/d. Up to five new drills are anticipated during 2006. Company net undeveloped lands were 15,000 acres at year-end 2005.

Marsden/Epping/Macklin/ Silverdale: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that range up to 18 API. Initial production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30 percent of the original oil in-place because many of the oil pools in this area have a strong natural water drive. Average oil production in this area during 2005 was approximately 4,400 bbl/d. Eight oil wells were drilled in 2005 and current oil production is approximately 3,600 bbl/d. In addition, a solution gas tie-in project that currently sells 300 Mcf/d of natural gas was completed at Marsden. During 2006, a 300 Mcf/d solution gas project at Macklin is expected to be put on-stream and eight to 10 new wells are planned. Company net undeveloped lands were 19,600 acres at year-end 2005.

Seal: Seal is a highly prospective property located in the Peace River oil sands area of northwest Alberta. Baytex holds a 100 percent working interest in approximately 100 sections of long-term oil sands leases. These oil deposits can be produced through horizontal well-bores at initial rates of approximately 150 bbl/d without resorting to the more capital intensive steam injection methods. A four-well stratigraphic test program completed during the first quarter of 2005 proved up significant extensions to our current development area located on the western block of these land holdings. Six horizontal wells drilled in late 2004 and early 2005 are currently producing approximately 500 bbl/d. The prospective undeveloped area of this westernmost block of Baytex leases comprises over 25,000 acres, and during 2006 we will drill three additional stratigraphic test wells to further delineate this acreage. In addition, two multi-lateral horizontal wells drilled with upper and lower production legs to more efficiently tap the 20 meter thick oil sand deposit will be completed and brought on-stream in 2006. Operators of adjoining lands are pursuing aggressive development programs that will contribute to vital infrastructure and allow enhanced marketing solutions for the region. As the region continues to develop, the Seal property will take an increasingly more prominent role in the Trust's development activity. Company net undeveloped lands in this area were 67,000 acres at year-end 2005.

Tangleflags: 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. As such, this property supplies longer-term development potential through a considerable number of uphole recompletion opportunities. Average production during 2005 was approximately 3,500 bbl/d of heavy oil and 1.4 MMcf/d of natural gas (3,700 boe/d). Current production is approximately 3,000 bbl/d and 2.1 MMcf/d. The growth in natural gas production was achieved through the conservation of solution gas produced in conjunction with the heavy oil. During 2006, Baytex plans to add three to five new wells, conduct 10 to 20 recompletions and continue tie-in of solution gas production. Company net undeveloped lands were 10,200 acres at year-end 2005.

Light Oil and Natural 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 currently provide approximately half of our cash flow. When Baytex converted from a traditional E&P company to an energy trust in 2003, Baytex Energy Trust produced approximately 12,000 boe/d of light oil and natural gas concentrated in southeastern and northern Alberta. Over the last two and a half years, Baytex's light oil and gas production has grown to its current level of approximately 14,000 boe/d through a combination of acquisitions and development activities. Moreover, the geographic scope of our light oil and gas operations has expanded to southwest Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Light Oil and Natural Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2005, production averaged 52.9 MMcf/d of natural gas and 3,842 bbl/d of hydrocarbon liquids (12,662 boe/d). In 2005, the District drilled 51 (41.9 net) wells resulting in 40 (33.4 net) gas wells, five (3.0 net) oil wells, and six (5.5 net) dry wells for a success rate of 88 percent (88 percent net). Company undeveloped lands in this district were approximately 425,600 net acres at year-end 2005.

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production, which is from the Belly River, Viking and Mannville formations, averaged approximately 6.0 MMcf/d of gas and 300 bbl/d of hydrocarbon liquids (1,300 boe/d) in 2005. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. Baytex plans to drill three wells in this area during 2006. Company net undeveloped lands were 27,400 acres at year-end 2005.

Darwin/Nina, Alberta: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Company-operated gas plants. Production during 2005 averaged approximately 4.0 MMcf/d (700 boe/d). Baytex plans to drill three wells during 2006 in the Nina/Darwin area. Company net undeveloped lands were 52,000 acres at year-end 2005.

Leahurst, Alberta: Production averaged approximately 5.0 MMcf/d (800 boe/d) in 2005 from this multi-zone, year-round access area. Natural gas from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Company-operated. In 2005, Baytex drilled 14 (11.3 net) wells for coal-bed methane production from the Horseshoe Canyon Coals (three of which were also completed in the Belly River formation), and four (4.0 net) Mannville natural gas wells. In 2006, Baytex may drill up to 12 Horseshoe Canyon CBM/Belly River wells and one Mannville well in the Leahurst area. Company net undeveloped lands were 20,600 acres at year-end 2005.

Red Earth/Goodfish, Alberta: This winter-access, multi-zone property was acquired by Baytex in 1997. Relatively shallow decline oil production from Granite Wash and Slave Point pools is treated at two Company-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Company-operated. Production during 2005 from this area averaged approximately 6.0 MMcf/d and 900 bbl/d of hydrocarbon liquids (1,900 boe/d). Baytex plans to drill four wells during 2006 in the Red Earth/Goodfish area. Company net undeveloped lands were 49,900 acres at year-end 2005.

Richdale/Sedalia, Alberta: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition. During 2005, production averaged approximately 9.0 MMcf/d and 21 bbl/d of hydrocarbon liquids (1,500 boe/d). This area has advantages of year-round access and multi-zone potential (Second White Specks, Viking and Mannville). Most of the gas production is processed by two Company-operated gas plants. Baytex plans to drill three wells during 2006 in this area. Company net undeveloped lands were 60,300 acres at year-end 2005.

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 Company-operated batteries and natural gas is compressed at four Company-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production during 2005 from this area averaged approximately 12.0 MMcf/d and 1,700 bbl/d of hydrocarbon liquids (3,700 boe/d). Baytex drilled nine wells in 2005 resulting in eight gas wells and one abandoned well, and plans to drill six wells and

recomplete three wells in 2006. Company net undeveloped lands were 34,500 acres at December 31, 2005.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2005 averaged approximately 2.0 MMcf/d and 700 bbl/d of hydrocarbon liquids (1,000 boe/d). Production comes from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Company-operated batteries and gas is processed at two outside-operated gas plants. Baytex plans to drill three wells and recomplete five additional wells during 2006 in the Turin area. Company net undeveloped lands were 29,500 acres at December 31, 2005.

MARKETING

Crude Oil

World crude oil prices rose in 2005 as strong economic growth combined with supply disruptions and geopolitical events to continue the upward momentum from 2004. World demand for oil and products grew by 1.3 percent in 2005, a modest increase following the enormous growth of 3.8 percent in 2004. The resulting price increase demonstrated that crude oil and products supplies were not able to respond to the continued demand growth as the world's drilling and refining operations were already operating at capacity. In North America, the largest impact on crude oil supplies came from Hurricanes Katrina and Rita in August and September 2005. Much of U.S. Gulf of Mexico oil and gas producing operations were forced offline, losing approximately 110 million barrels of cumulative oil production through year-end.

The lack of excess OPEC productive capacity also contributed to record prices in 2005. After increasing production in late 2004 to meet surging Asian demand, OPEC production remained fairly flat. Geopolitical events again played a role as the ongoing conflict in Iraq, unrest in Nigeria, politics in Russia and the more-recent Iranian nuclear stand-off have left market participants very nervous.

Benchmark WTI prices began the year around US$42.00 per bbl, climbed to an all-time high of US$69.81 per bbl on August 30 th, and ended the year over US$61 per bbl. The average WTI price for 2005 was US$56.56 per bbl, an increase of 37 percent from US$41.40 in 2004.

Canadian crude oil prices, while enjoying the strength in world prices, were tempered by the rising Canadian dollar against its U.S. counterpart. Canadian Par crude at Edmonton averaged $68.75 per bbl in 2005, up 31 percent from $52.57 in 2004.

With OPEC increasing production in late 2004, supplies of heavy and sour crude oil increased and prices versus benchmark light sweet prices deteriorated during 2005. Canadian heavy oil prices mirrored this trend as the differential between WTI and Lloyd blend prices in Alberta averaged US$21.82 per bbl in 2005 (39 percent of WTI) compared to US$14.01 per bbl in 2004 (34 percent of WTI).

Baytex's light oil and natural gas liquids prices averaged $53.84 per bbl before hedging in 2005 compared to $48.64 in 2004. Our heavy oil prices averaged $37.38 per bbl in 2005, compared to $30.32 in 2004.

In October 2002, Baytex signed a five-year crude oil supply agreement with Frontier Oil and Refining Company ("Frontier") of Houston, Texas. The agreement calls for Baytex to deliver 20,000 bbl/d of Lloyd Blend ("LLB") quality crude at Hardisty, Alberta through the Express Pipeline to Guernsey, Wyoming. The blended crude is comprised of approximately 16,000 barrels of Baytex production and 4,000 bbl/d of diluent. Prices are fixed at 71 percent of WTI or a 29 percent LLB differential which represents the long-term average differential since 1986. This contract significantly reduces the volatility of Baytex's cash flow from its heavy oil operations.

Going forward, 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 2006 on 8,000 bbls/d, at a weighted average price from US$55 to US$84.39 per bbl and for 5,000 bbls/d for 2007 at weighted average prices from US$55 to US$83.69 per bbl.

Baytex is working to develop a solution to the marketing and infrastructure issues present in the Seal area and management is optimistic that solutions can be developed which will accelerate full-scale field development.

Natural Gas

Natural gas prices in North America were strong again in 2005, reflecting high oil prices, concerns over gas supplies and the severe loss of production from the hurricane activity, where 570 Bcf of production was lost during the fourth quarter. U.S. gas prices represented by the NYMEX futures contract averaged US$8.55 per Mcf in 2005, an increase of 40 percent from US $6.09 in 2004. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $8.71 per Mcf in 2005, up 33 percent from $6.53 in 2004. Five-year averages are US$5.54 per Mcf for the NYMEX contract and $6.00 for Alberta daily prices.

Baytex received an average of $8.22 per Mcf for 2005 natural gas sales compared to $6.46 in 2004.

For 2006 Baytex has entered into several physical forward sales contracts. These agreements have locked in seasonal natural gas prices over the year at prices above the current forward strip.

OPERATIONS

Production The Trust's average production for fiscal 2005 increased by three percent to 35,177 boe/d from 34,022 boe/d for fiscal 2004.

Light oil & NGL production increased by 76% to 3,842 bbl/d from 2,172 bbl/d for last year. Heavy oil production for 2005 was down 7% to 21,265 bbl/d compared to 22,703 bbl/d in 2004. Natural gas production increased by 10% to average 60.4 MMcf/d for 2005 compared to 54.9 MMcf/d for 2004. The reasons for the increase in production for light oil and NGL and natural gas is due to the acquisition completed in 2004 and the subsequent development of these assets. The decrease in heavy oil production is due to the reduction in drilling, where 66 net heavy oil wells were drilled in 2005 compared to 95 net wells drilled in 2004.

Production by Area	Light Oil and NGLs (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (MMcf/d)	Oil Equivalent (boe/d)
2005				
Heavy Oil District	—	21,265	7.5	22,515
Light Oil and Natural Gas District	3,842	—	52.9	12,662
Total Production	3,842	21,265	60.4	35,177
2004				
Heavy Oil District	—	22,703	8.9	24,177
Light Oil and Natural Gas District	2,172	—	46.0	9,845
Total Production	2,172	22,703	54.9	34,022

Revenue Petroleum and natural gas sales for 2005 increased by four percent to $546.9 million from $420.4 million for fiscal 2004. Benchmark WTI crude oil averaged US$56.56 per barrel for 2005, representing a 37 percent increase over the US$41.40 per barrel for 2004. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$0.8253 in 2005 compared to US$0.7683 in 2004. The Trust's light oil and NGLs price increased to $53.84 per barrel from $48.64 per barrel. The heavy oil price increased 23 percent to $37.38 per barrel in 2005 from $30.32 per barrel in 2004. Natural gas prices were 27 percent higher in 2005, averaging $8.22 per Mcf compared to $6.46 per Mcf during the previous year. Overall, after accounting for $48.5 million of realized losses on

financial derivative contracts, the Trust averaged $38.82 per boe for 2005, a 41 percent increase from $27.48 per boe received in the prior year.

For 2005, light oil and NGL revenue increased 95% from the same period last year due to an 11% increase in wellhead prices and a 76% increase in production. Revenue from heavy oil increased 15% due to a 23% increase in wellhead prices partially offset by a 7% decrease in production. Revenue from natural gas increased 40% compared to 2004, as production increased 10% combined with a price increase of 27%.

	2005		2004	
Gross Revenue Analysis	$ thousands	$/Unit (1)	$ thousands	$/Unit (1)
Oil revenue (barrels)				
Light oil & NGL	75,507	53.84	38,673	48.64
Heavy oil	290,163	37.38	252,016	30.32
Derivative contract loss	(48,462)	(6.24)	(78,124)	(8.58)
Total oil revenue	317,208	34.61	212,565	23.34
Natural gas revenue (Mcf)	181,270	8.22	129,711	6.46
Total revenue (boe @ 6:1)	498,478	38.82	342,276	27.48

(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/Mcf.

Royalties For the year ended December 31, 2005, royalties increased to $81.9 million from $66.0 million for last year. Total royalties in 2005 were 15.0% of sales, compared to 15.7% of sales for 2004. For 2005, royalties were 15.1% of sales for light oil and NGL, 12.4% for heavy oil and 19.0% for natural gas. These rates compared to 14.1%, 13.3% and 20.9%, respectively, for 2004. The royalty rate for natural gas was lower in 2005 due to a retroactive adjustment in the gas cost allowance used in the calculation of royalties.

Operating Expenses Operating expenses for 2005 increased to $110.6 million from $89.1 million in 2004. Operating expenses were $8.62 per boe for 2005 compared to $7.15 per boe for the prior year. In 2005, operating expenses were $9.06 per barrel of light oil and NGL, $9.56 per barrel of heavy oil and $1.08 per Mcf of natural gas versus $9.51, $7.83 and $0.82, respectively, for the same period a year earlier.

Transportation Expenses Transportation expenses for 2005 were $22.4 million compared to $18.7 million for 2004. These expenses were $1.74 per boe in 2005 compared to $1.50 in 2004. Transportation expenses were $2.11 per barrel of oil and $0.14 per Mcf of natural gas in 2005, and $1.66 per barrel of oil and $0.18 per Mcf of natural gas in 2004.

Net Revenue

	Light oil & NGLs ($ /bbl)	Heavy Oil ($ /bbl)	Total Oil & NGL ($ /bbl)	Natural Gas ($ /Mcf)	BOE ($ /boe)

	2005	2004	2005	2004	2005	2004	2005	2004	2005	2004
Sales price	**53.84**	48.64	**37.38**	30.32	**39.90**	31.91	**8.22**	6.46	**42.60**	33.75
Royalties	**(8.13)**	(6.88)	**(4.63)**	(4.02)	**(5.17)**	(4.27)	**(1.57)**	(1.35)	**(6.38)**	(5.30)
Operating costs	**(9.06)**	(9.51)	**(9.56)**	(7.83)	**(9.48)**	(7.97)	**(1.08)**	(0.82)	**(8.62)**	(7.15)
Transportation	**(1.16)**	(0.92)	**(2.28)**	(1.73)	**(2.11)**	(1.66)	**(0.14)**	(0.18)	**(1.74)**	(1.50)
Net revenue	**35.49**	31.33	**20.91**	16.74	**23.14**	18.01	**5.43**	4.11	**25.86**	19.80

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses General and administrative expenses for the year were $16.0 million, compared to $15.2 million for the prior year. On a per sales unit basis, these expenses were $1.25 per boe in 2005 and $1.22 per boe in 2004. In accordance with our full cost accounting policy, no expenses were capitalized in either 2005 or 2004.

($ thousands)	2005	2004
Gross corporate expense	22,568	20,413
Operator's recoveries	(6,558)	(5,170)
Net expenses	16,010	15,243

Unit Based Compensation Expense Compensation expense related to the Trust's unit rights incentive plan was $5.3 million for 2005 compared to $4.6 million for 2004.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Until July 1, 2005, the Trust accounted for stock based compensation based on the intrinsic value of the awards at each reporting date. Effective July 1, 2005, on a prospective basis, the trust began valuing options using the fair value based method. In the fourth quarter of 2005, the trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

Interest Expense In 2005, interest expense was $33.1 million for the year compared to $19.4 million last year. The increase in total interest expense is primarily due to the increased debt used to finance acquisitions completed in 2004, plus a gradual increase in interest rates.

Foreign Exchange The foreign exchange gain for 2005 was $6.8 million compared to $16.0 million in the prior year. The 2005 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8577 at December 31, 2005 compared to 0.8308 at December 31, 2004. The 2004 gain is based on translation at 0.8308 at December 31, 2004 compared to 0.7737 at December 31, 2003.

Depletion, Depreciation and Accretion Depletion, depreciation and accretion increased to $167.1 million for 2005 compared to $160.8 million for last year. On a sales-unit basis, the provision for the current year was $13.02 per boe compared to $12.91 per boe for 2004.

Income Taxes Current tax expenses were $8.7 million for 2005 compared to $9.0 million last year. The current tax expense is comprised of $6.9 million of Saskatchewan Capital Tax and $1.8 million of Large Corporation Tax compared to $7.0 million and $2.0 million, respectively, in 2004.

The fiscal 2005 provision for future income taxes was a recovery of $7.1 million compared to a recovery of $41.2 million for the prior year. The future income tax recovery for 2004 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income.

Canadian Tax Pools

($ thousands)	2005	2004
Cumulative Canadian Exploration Expense	4,953	1,283
Cumulative Canadian Development Expense	129,596	99,741
Cumulative Canadian Oil and Gas Property Expense	162,974	155,930
Undepreciated Capital Cost	179,009	195,235
Other	31,087	39,430
Total tax pools	507,619	491,619

Cash Flow from Operations Cash flow from operations in 2005 increased 67 percent to $227.5 million from $136.0 million for the previous year. On a barrel of oil equivalent basis, cash flow from operations was $17.72 for 2005 compared to $10.03 for 2004. The increase is due to higher sales revenue and a lower realized loss from financial derivative contracts in 2005.

	2005		2004	
Cash Flow Netbacks	**$/boe**	**Percent**	**$/boe**	**Percent**
Production revenue	42.60	100	33.75	100
Derivative contract loss	(3.77)	(9)	(6.27)	(19)

Royalties	(6.38)	(15)	(5.30)	(16)
Operating expenses	(8.62)	(20)	(7.15)	(21)
Transportation	(1.74)	(4)	(1.50)	(4)
Operating netbacks	22.09	52	13.53	40
General and administrative expenses	(1.25)	(3)	(1.22)	(4)
Interest expense	(2.44)	(6)	(1.56)	(4)
Current income taxes	(0.68)	(1)	(0.72)	(2)
Cash flow netbacks	17.72	42	10.03	30

Net Income Net income for 2005 was $79.9 million compared to $16.8 million for 2004. The increased petroleum and natural gas sales realized through higher wellhead prices in 2005 were offset by increased operating expenses, a lower foreign exchange gain and a lower future income tax recovery. Net income for each year has also been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income relating to the outstanding exchangeable shares.

Capital Expenditures Capital expenditures during 2005 totaled $152 million, with $130 million spent on exploration and development activities and $22 million spent on acquisitions net of dispositions of assets. For the year ended December 31, 2005, the Trust participated in the drilling of 118 (107.3 net) wells, resulting in 64 (60.4 net) oil wells, 41 (34.4 net) gas wells, four (4.0 net) stratigraphic test wells and nine (8.5 net) dry holes compared to prior year activities of 138 (135.0 net) wells, including 104 (103.1 net) oil wells, 16 (14.4 net) gas wells, seven (6.5 net) stratigraphic test wells and 11 (11.0 net) dry holes. In September 2005, Baytex purchased 3,500 boe/d of mainly heavy oil production at Celtic for $69 million. An unsolicited offer in December resulted in the sale of the SAGD production just acquired for $45.3 million. The decision to acquire these assets was based on the primary (cold) development opportunities which have been retained by Baytex. Production from the retained assets has grown to a current rate of over 3,000 boe/d from the original 1,750 boe/d at the time of acquisition. An active capital program has been planned for this area in 2006, including the drilling of 30 wells. This acquisition complements existing operations in the core area of Tangleflags and provides numerous low cost development opportunities.

	Year Ended December 31	
($ thousands)	**2005**	**2004**
Land	**7,126**	8,744
Seismic	**4,949**	1,283
Drilling and completion	**90,180**	55,322
Equipment	**23,611**	25,982
Other	**4,626**	3,152
Total exploration and development	**130,492**	94,483
Corporate acquisition	**—**	111,042
Property acquisitions	**70,986**	89,582
Property dispositions	**(49,029)**	(14,441)
Total capital expenditures	**152,449**	280,666

Liquidity and Capital Resources At December 31, 2005, total net debt (including working capital, but excluding notional mark-to-market assets or liabilities) was $423.7 million compared to $412.5 million at December 31, 2004. The modest increase in total debt at year-end 2005 compared to 2004 is reflective of the Trust's ability to fund distributions and capital expenditures by cash flow from operations.

On June 6, 2005 the Trust issued $100 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The 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 debentures mature on December 31, 2010 at which time they are due and payable. The net proceeds were used to reduce outstanding bank indebtedness.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity as at the date of issue. Issue costs are amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. As at December 31, 2005, $22.8 million principal amount of debentures had been tendered for conversion into trust units.

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $250 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2005 a total of $123.6 million had been drawn under the credit facilities.

Another component of the Company's debt is the US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010. They are unsecured and are subordinate to the Company's bank credit facilities. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Unitholders' Equity The Trust is authorized to issue an unlimited number of trust units. On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95% of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued for treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units 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. The Trust can also acquire trust units to be issued under the DRIP at prevailing market rates.

On December 20, 2004, the Trust issued 3,600,000 trust units at $12.80 per unit for gross proceeds of $46.1 million pursuant to a prospectus.

Non-controlling Interest The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. At December 31, 2005, there were 1.6 million exchangeable shares outstanding. During 2005, a total of 0.3 million exchangeable shares were exchanged for trust units. The number of trust units issuable upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2005 was 1.37201 trust units per

exchangeable share (December 31, 2004 – 1.21472 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

Cash Distributions During 2005 total cash distributions of $1.80 per unit were declared. The monthly cash distribution of $0.15 per unit has been maintained since the inception of the Trust in September 2003 and was increased to $0.18 per unit in 2006.

Off Balance Sheet Arrangements and Contractual Obligations

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Contractual Obligations at December 31, 2005
($ thousands)

	Payments Due			
	Total	Within 1 year	1-3 years	4-5 years
Operating leases	8,117	1,621	5,834	662
Transportation agreements	3,446	2,052	1,394	—
Total contractual obligations	11,563	3,673	7,228	662

The Trust also has ongoing obligations related to the abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

Risk and Risk Management The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the

possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum

and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Company's Board of Directors, assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserve estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, The Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the US dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in US dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar denominated long-term notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates. Changes in interest rates also impact the Company's interest rate swap contract which converts the fixed interest rate of 9.625 percent on the US$179.7 million notes to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

The Trust's current position with respect to its financial derivative contracts is detailed in note 17 of the consolidated financial statements.

A summary of certain risk factors relating to our business is included in our Annual Information Form under the Risk Factors section.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

Oil And Gas Accounting The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserve estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in

assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation.

Impairment of Petroleum and Natural Gas Assets Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. If reserve estimates are revised downward, net income could be affected by any additional depletion and deprecation recorded under the ceiling test calculation and could result in a significant accounting loss for a particular period.

Asset Retirement Obligations The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

CHANGE IN ACCOUNTING POLICY

Unit-Based Compensation Until July 1, 2005, the Trust accounted for stock based compensation based on the intrinsic value of the awards at each reporting date. Effective July 1, 2005, on a prospective basis, the trust began valuing options using the fair value based method. In the fourth quarter of 2005, the trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

As a result of retroactively adopting the fair value method of estimating compensation expense, net income for the comparative year ended December 31, 2004 was increased by $3.0 million, net of non-controlling interest of $0.09 million. The opening 2004 accumulated deficit was increased by $1.7 million, net of non-controlling interest of $0.1 million. There was also a decrease in unitholders' capital of $0.07 million during 2004 relating to the transfer of value from contributed surplus on exercise of unit option rights. There was no impact on cash flow as a result of adopting this policy.

NEW ACCOUNTING PRONOUNCEMENTS

Financial Instruments In January, 2005 the CICA issued three new standards relating to the reporting of financial instruments in financial statements. These standards introduce new requirements for the recognition and measurement of financial instruments and comprehensive income. Section 3855, "Financial Instruments – Recognition and Measurement" requires that all financial instruments, including derivatives, are to be included on a company's balance sheet and measured, either at their fair values or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized cost. The standard also provides guidance on when gains and losses as a result of changes in fair values are to be recognized in the income statement.

The issuance of the new Section 3855 will result in amendments to Section 3860 "Financial Instruments – Disclosure and Presentation" to make the scope and definitions consistent with that of the new Section 3855, including expanding the scope to include certain commodity-based contracts, and to update certain disclosures in light of the introduction of Section 3855. Other Handbook Sections have also been amended for conformity with the new standards.

Section 3865 "Hedges", extends the existing requirements for hedge accounting currently under AcG -13. This new section allows for the optional treatment of accounting for financial instruments that are designated as either fair value hedges, cash flow hedges or hedges of a net investment in a self-sustaining foreign operation. For a fair value hedge, the gain or loss on a derivative hedging item, or the gain or loss on a non-derivative hedging item attributable to the hedged risk, is recognized in net income in the period of change together with the offsetting loss or gain on the hedged item attributable to the hedged risk. The carrying amount of the hedged item is adjusted for the hedged risk. For a cash flow hedge, the effective portion of the hedging item's gain or loss is initially reported in other comprehensive income and subsequently reclassified to net income when the hedged item affects net income. For a hedge of a net investment in a self-sustaining foreign operation the same accounting is followed as for a cash flow hedge.

A new location for recognizing certain gains and losses – other comprehensive income – has been introduced with the issued of Section 1530, "Comprehensive Income". An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other Comprehensive Income. This standard requires that a company should present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements. Exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation, previously recognized in a separate component of shareholders' equity, in accordance with Section 1650, "Foreign Currency Translation", will now be recognized in a separate component of other comprehensive income.

These three new Handbook Sections are effective date for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust is evaluating the impact the adoption of these new standards will have on its consolidated financial statements.

Non-Monetary Transactions In June 2005, The CICA issued Section 3831 "Non-Monetary Transactions", which replaces the culmination of earnings test with a commercial substance test as the criteria for fair value measurement. In addition, fair value measurement is clarified. The Trust does not expect application of this new standard to have a material impact on its consolidated financial statements.

FOURTH QUARTER 2005

The following discussion reviews the Trust's results of operations for the fourth quarter of 2005.

Light oil and NGL production for the fourth quarter of 2005 increased by 44% to 4,022 bbl/d from 2,786 bbl/d a year earlier. Heavy oil production increased 7% to 24,051 bbl/d for the fourth quarter of 2005 compared to 22,490 bbl/d a year ago. Natural gas production increased by 6% to 58.9 MMcf/d for the fourth quarter of 2005 compared to 55.5 MMcf/d for the same period last year. The increase in light oil and NGL and natural gas production is due to the acquisitions completed in 2004 and the subsequent development of these assets. The increase in heavy oil production is attributable to the Celtic acquisition made during the year.

Petroleum and natural gas sales increased 46% to $162.4 million for the fourth quarter of 2005 from $111.5 million for the same period in 2004 . Revenue from light oil and NGL for the fourth quarter of 2005 increased 60% from the same period a year ago due to a 44% increase in production and a 11% increase in wellhead prices. Revenue from heavy oil increased 29% due to a 7% increase in production and a 21% increase in wellhead prices. Revenue from natural gas increased 72% as the result of a 62%

increase in wellhead prices and a 6% increase in production. Total royalties increased to $27.3 million for the fourth quarter of 2005 from $17.4 million in 2004. This increase is reflective of the increase in total revenue.

Total royalties for the fourth quarter of 2005 were 16.8% of sales compared to 15.6% of sales for the same period in 2004. For the fourth quarter of 2005, royalties were 16.2% of sales for light oil and NGL, 11.7% for heavy oil and 24.3% for natural gas. These rates compared to 15.9%, 13.5% and 19.5%, respectively, for the same period last year.

Operating expenses for the fourth quarter of 2005 increased to $33.3 million from $24.3 million in the corresponding quarter last year. Operating expenses were $9.55 per boe for the fourth quarter of 2005 compared to $7.63 per boe for the fourth quarter of 2004. The increase in operating expenses per boe was primarily due to an inflationary cost environment for fuel and oilfield services, and the addition of heavy oil production utilizing SAGD technology which was disposed of at year-end 2005. For the fourth quarter of 2005, operating expenses were $6.28 per barrel of light oil and NGL, $11.00 per barrel of heavy oil and $1.22 per Mcf of natural gas. The operating expenses for the same period a year ago were $8.57, $8.61 and $0.83, respectively.

Transportation expenses for the fourth quarter of 2005 were $6.0 million compared to $4.6 million for the fourth quarter of 2004. These expenses were $1.71 per boe for the fourth quarter of 2005 compared to $1.43 for the same period in 2004. Transportation expenses were $2.02 per barrel of oil and $0.14 per Mcf of natural gas. The corresponding amounts for 2004 were $1.58 and $0.17, respectively.

General and administrative expenses for the fourth quarter of 2005 increased slightly to $4.6 million from $4.1 million in 2004. On a per sales unit basis, these expenses were $1.32 per boe for the fourth quarter of 2005 compared to $1.28 per boe for the same period in 2004. In accordance with our full cost accounting policy, no general and administrative expenses were capitalized in either the fourth quarter of 2005 or 2004.

Compensation expense related to the Trust's unit rights incentive plan was $1.8 million for the fourth quarter of 2005 compared to $1.0 million for the fourth quarter of 2004.

Interest expense increased to $9.7 million for the fourth quarter of 2005 from $6.4 million for the same quarter last year, primarily due to the increased debt used to finance acquisitions, plus a gradual increase in interest rates.

Foreign exchange in the fourth quarter of 2005 was a loss of $0.9 million compared to a gain of $10.9 million in the prior year. The loss is based on the translation of the US dollar denominated long-term debt at 0.8577 at December 31, 2005 compared to 0.8613 at September 30, 2005. The 2004 gain is based on translation at 0.8308 at December 31, 2004 compared to 0.7912 at September 30, 2004.

The provision for depletion, depreciation and accretion at $41.6 million for the fourth quarter of 2005 is almost unchanged from the same quarter a year ago despite higher production, due to a lower depletion rate resulting from low-cost proved reserves added from the Celtic acquisition. On a sales-unit basis, the provision for the current quarter was $11.91 per boe compared to $13.04 per boe for the same quarter in 2004.

Net income for the fourth quarter of 2005 was $35.2 million compared to $42.7 million for the fourth quarter in 2004. The variance was the result of higher production and higher sales prices, offset by foreign exchange losses and an increase in future tax provision.

Trust Unit Information

At February 28, 2006, the Trust had 71,231,684 units outstanding and the Company had 1,594,733 exchangeable shares outstanding. The exchange ratio at February 28, 2006 was 1.39624 trust units per exchangeable share.

At February 28, 2006, the Trust had $55.0 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

Selected Annual Information

Financial

($ thousands, except per unit amounts)	2005	2004 (3)	2003 (2), (3)
Revenue	546,940	420,400	403,022
Net income (1)	79,876	16,764	34,141
Per unit basic (1)	1.19	0.27	0.63
Per unit diluted (1)	1.15	0.26	0.59
Total assets	1,105,567	1,104,136	982,640
Total long-term financial liabilities	283,565	216,583	232,562
Cash distributions declared per unit	1.80	1.80	0.60

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2003 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements.

(2) The financial information for 2003 has been restated for the adoption of the new accounting standards related to asset retirement obligations and transportation expenses.

(3) The financial information for 2004 and 2003 has been restated for the adoption of fair value based method of calculating unit-based compensation expense.

Overall production for 2005 was 35,177 boe per day which represented a three percent increase from 34,022 boe per day in 2004. Average wellhead prices received during 2005 were $42.60 per boe compared to $33.75 during 2004. Production in 2003 was 36,686 boe per day. Average wellhead prices received in 2003 were $28.07 per boe.

Quarterly Information

Financial (unaudited)

($ thousands, except per unit amounts)	2005				2004(2)			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	162,356	154,930	118,379	111,275	111,521	108,216	104,517	96,146
Cash flow from operations	65,487	67,501	49,937	44,540	28,144	32,235	36,944	38,689
Per unit basic	0.95	1.00	0.75	0.67	0.44	0.50	0.57	0.60
Per unit diluted	0.86	0.90	0.71	0.64	0.42	0.49	0.57	0.60
Cash distribution declared per unit	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45
Net income (loss) (1)	35,184	39,524	16,779	(11,611)	42,696	(10,672)	(10,585)	(4,674)
Per unit basic (1)	0.51	0.59	0.25	(0.17)	0.67	(0.17)	(0.17)	(0.08)
Per unit diluted (1)	0.48	0.55	0.25	(0.17)	0.66	(0.17)	(0.17)	(0.07)

(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares. The net income and net income per unit for 2004 have been restated due to the retroactive application of the new accounting standard for non-controlling interest (see note 3 of the consolidated financial statements).

(2) The financial information for 2004 has been restated for the adoption of fair value based method of calculating unit-based compensation expense.

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production								
Light oil and NGLs (bbls/d)	4,022	4,063	3,404	3,876	2,786	1,890	1,952	2,058
Heavy oil (bbls/d)	24,051	20,061	19,653	21,279	22,490	22,083	22,927	23,322
Total oil and NGLs (bbls/d)	28,073	24,124	23,058	25,155	25,276	23,974	24,879	25,380
Natural gas (MMcf/d)	58.9	63.9	59.3	59.5	55.5	50.9	57.2	56.0
Oil equivalent (boe/d @ 6:1)	37,895	34,780	32,937	35,068	34,525	32,454	34,411	34,709
Average Prices								
WTI oil (US$/bbl)	60.02	63.19	53.17	49.84	48.28	43.88	38.32	35.15
Edmonton par oil ($/bbl)	71.18	76.51	65.76	61.44	57.72	56.32	50.59	45.59
BTE light oil ($/bbl)	55.78	59.24	53.06	46.69	50.46	52.63	47.55	43.50
BTE heavy oil ($/bbl)	37.75	45.39	35.71	30.83	31.24	34.69	29.21	26.29
BTE total oil ($/bbl)	40.33	47.74	28.27	33.27	33.35	36.11	30.63	27.70
BTE natural gas ($/Mcf)	10.69	8.39	7.08	6.69	6.60	6.16	6.61	6.43
BTE oil equivalent ($/boe)	46.48	48.54	39.53	35.21	35.03	36.34	33.12	30.63

2006 Guidance

Baytex has set a $105 million exploration and development capital budget for 2006, with approximately $65 million allocated for activities relating to heavy oil and $40 million for activities relating to natural gas and light oil. Production for the year is targeted to average 35,000 boe/d, with heavy oil at 21,000 bbl/d, natural gas at 61.2 MMcf/d and light oil and NGL at 3,800 bbl/d.

Baytex has entered into the following contracts to provide downside protection to 2006 and 2007 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

Financial Derivative Contracts

At December 31, 2005, the Trust had derivative contracts for the following:

OIL	Period	Volume	Price	Index
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $80.85	WTI
Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $84.18	WTI

Price collar	Calendar 2006	2,000 bbl/d	US$55.00 – $85.30	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.10	WTI
Price collar	Calendar 2006	1,000 bbl/d	US$55.00 – $87.35	WTI

FOREIGN CURRENCY

	Period	Amount	Floor	Cap
Collar	Calendar 2006	US$3,000,000 per month	CAD/US$1.1700	CAD/US$1.2065

INTEREST RATE SWAP

Period	Principal	Rate
November 2003 to July 2010	US$179,699,000	3-month LIBOR plus 5.2%

In 2006, the Company entered into derivative contracts for the following:

OIL

	Period	Volume	Price	Index
Price collar	Calendar 2007	2,000 bbl/d	US$55.00 – $83.60	WTI
Price collar	Calendar 2007	3,000 bbl/d	US$55.00 – $83.75	WTI

FOREIGN CURRENCY

	Period	Amount	Floor	Cap
Collar	February 1, 2006 to December 31, 2006	US$4,000,000 per month	CAD/US$1.1500	CAD/US$1.1835
Collar	January 9, 2006 to December 31, 2006	US$3,000,000 per month	CAD/US$1.1500	CAD/US$1.1780

Physical Sale Contracts

GAS

	Period	Volume	Price
Fixed price	January 1, 2006 to February 28, 2006	3,000 GJ/d	CAD$10.00
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.07
Fixed price	January 1, 2006 to March 31, 2006	5,000 GJ/d	CAD$10.20
Fixed price	January 1, 2006 to March 31, 2006	2,000 GJ/d	CAD$10.63
Fixed price	March 1, 2006 to March 31, 2006	3,000 GJ/d	CAD$11.53
Fixed price	April 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$8.40
Fixed price	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$9.01
Price collar	January 1, 2006 to October 31, 2006	5,000 GJ/d	CAD$7.50 - $13.40
Price collar	April 1, 2006 to October 31, 2006	2,000 GJ/d	CAD$7.80 - $10.55
Price collar	April 1, 2006 to October 31, 2006	3,000 GJ/d	CAD$9.50 – $12.60

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 17 to the December 31, 2005 consolidated financial statements for description of accounting treatment of these derivative contracts.

Evaluation of Disclosure Controls and Procedures.

Raymond Chan, the President and Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer of Baytex (together the “Disclosure Officers”), are responsible for establishing and maintaining disclosure controls and procedures for Baytex. For the year ended December 31, 2005, the Disclosure Officers evaluated the effectiveness of the disclosure controls and procedures. As a result of this evaluation, the Disclosure Officers have concluded that the disclosure controls and procedures are

effective to provide reasonable assurance that all material or potentially material information about the activities of the Trust is made known to them by others within Baytex.

It should be noted that while our President and Chief Executive Officer and Chief Financial Officer believe that Baytex’s disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

Exhibit 99.4

CERTIFICATIONS

I, Raymond T. Chan, President and Chief Executive Officer of Baytex Energy Ltd., certify that:

1. I have reviewed this annual report on Form 40-F of Baytex Energy Trust;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and we have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of the internal controls over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's controls over financial reporting.

Date: March 29, 2006

BAYTEX ENERGY TRUST

By: Baytex Energy Ltd.

By: (signed) "Raymond T. Chan"
Name: Raymond T. Chan, CA
Title: President and Chief Executive Officer

Exhibit 99.5

CERTIFICATIONS

I, W. Derek Aylesworth, Chief Financial Officer of Baytex Energy Ltd., certify that:

1. I have reviewed this annual report on Form 40-F of Baytex Energy Trust;

2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the issuer and we have:

(a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;

(b) evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c) disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of the internal controls over financial reporting, to the issuer's auditors and the audit committee of issuer's board of directors (or persons performing the equivalent function):

(a) all significant deficiencies and material weakness in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

(b) any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's controls over financial reporting.

Date: March 29, 2006

BAYTEX ENERGY TRUST

By: Baytex Energy Ltd.

By: (signed) "W. Derek Aylesworth"
Name: W. Derek Aylesworth, CA
Title: Chief Financial Officer

Exhibit 99.6

Certification

In connection with the annual report of Baytex Energy Trust (the "Trust") on Form 40-F for the fiscal year ending December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Raymond T. Chan, President & Chief Executive Officer of Baytex Energy Ltd. certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly represents, in all material respects, the financial condition and results of operations of the Company.

Registrant: BAYTEX ENERGY TRUST
By: Baytex Energy Ltd.

By: (signed) "Raymond T. Chan"
Name: Raymond T. Chan, CA
Title: President and Chief Executive Officer

Date at Calgary, Alberta, as of March 29, 2006

Exhibit 99.7

Certification

In connection with the annual report of Baytex Energy Trust (the "Trust") on Form 40-F for the fiscal year ending December 31, 2005 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Derek Aylesworth, Chief Financial Officer of Baytex Energy Ltd., certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2. The information contained in the Report fairly represents, in all material respects, the financial condition and results of operations of the Trust.

Registrant: BAYTEX ENERGY TRUST

By: Baytex Energy Ltd.

Date at Calgary, Alberta, as of March 29, 2006

By: (signed) "W. Derek Aylesworth"
Name: W. Derek Aylesworth, CA
Title: Chief Financial Officer

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

We consent to the use of our reports dated March 7, 2006 (which audit report expresses an unqualified opinion on the financial statements and includes Comments by Independent Registered Chartered Accountants on Canada - United States of America Reporting Differences referring to a restatement of the financial statements as described in notes 3 and 19 to the consolidated financial statements), appearing in the Annual Report on Form 40-F of Baytex Energy Trust for the year ended December 31, 2005.

By: (signed) "Deloitte & Touche LLP"
Deloitte & Touche LLP
Independent Registered Chartered Accountants
Calgary, Alberta, Canada

March 7, 2006

Geological and Petroleum Engineering Consultalts

Sproule ASSOCIATES LIMITED

Executive Officers, Managers and Associates
K.H. Crowther*, B.S., P.Eng., *President*
R.K. MacLeod*, B.S., P.Eng., *Executive Vice-President*
R. Cech*, M.Sc., P.Eng., *Senior Vice-President, International*
J.L. Chipperfield*, B.Sc., P.Geol., *Vice-President, Geoscience*
H.J. Helwerda*, B.Sc., P.Eng., *Vice-President, Engineering* Canada and U.S.
R.N. Johnson*, B.Sc., P.Eng., *Manager, Engineering;* Corporae Secretary
D.W.C. Ho*, B.A.Sc., P.Eng., *Manager, Engineering*
K.P. McDonald, C.A., *Controller*

* *Director*

D.J. Carsted, CD, B.Sc., P.Geol., *Manager, Geoscience*
R. Gerritse, B.Sc., *Manager, Systems*
M.W. Maughan, B.S., P.Geol., C.P.G., *Manager, Geoscience*
L.S. O'Connor, B.S., C.P.G., *Manager, Denver*
G.D. Robinson, B.Sc., P.Eng., *Manager, Engineering*
J. W. Arsenault, B.S. Eng.
G.R. Finnis, B.S.c., P.Eng.
H.J. Firla, B.S., P.Eng.
C.M.F. Galas, Ph.D., P.Eng.
B.F. Jose, M.Sc., P.Geoph.
P.B. Jung, B.S., P.Eng.
D.A. King, B.Sc., P.Eng

A. Kovaltchouk, M.Sc., P.Geol.
M.J. O'Blenes, M.Sc., P.Eng.
S.W. Pennell, B.Sc., Eng.
M.W. Sargent, Ph.D., P.Geol.
J.P. Seidle, Ph.D., P.E.
P.C. Sidey, B.Sc., P.Eng.
C.P. Six, B.Sc., P.Eng.
N.T. Stewart, B.A.Sc., P.Eng.
W.J. Waddell, B.Sc., P.Geol.
F.P.R. Williams, B.Eng., P. Eng.
D.W. Woods, B.Ed., B.Sc., P.Eng.

Ref.: 2077.15800

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated February 24, 2006 and effective December 31, 2005, evaluating the oil, natural gas and natural gas liquids reserves attributable to Baytex Energy Trust, entitled “Evaluation of the P&NG Reserves of Baytex Energy Trust (As of December 31, 2005)”, (the “Report”).

We hereby consent to the references to our name in the Company’s Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and the Company’s registration statement on Form F-9 (File No. 333-89714).

We also confirm that we have read the Company’s Annual Information Form for the year ended December 31, 2005 dated March 21, 2006, and that we have no reason to believe that there are any misrepresentations in the information contained therein that was derived from the Report or that is within our knowledge as a result of the services we peformed in connection with such Report.

Sincerely,

/s/ Ken H. Crowther, P.Eng.

Ken H. Crowther, P.Eng.
President

Calgary, Alberta, Canada
March 23, 2006

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