U.S. SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

(CHECK ONE)

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

or

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

For the fiscal year ended: December 31, 2004
Commission File Number: 333-07612

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:
NONE	

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

TRUST UNITS

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.

Trust Units: 66,538,252

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

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

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, 2004, see Exhibit 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, 2004, including the report of independent registered chartered accountants with respect thereto, see Exhibit 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 20 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, 2004, see Exhibit 3 of this Annual Report on Form 40-F.

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. In the event that the Company:

(i) amends 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

(ii) grants a 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,

the Company will disclose on its website any amendment to, or waiver of, a provision of its Code of Ethics within five business days following the date of any such amendment or waiver, and will, in the case of a waiver, name the persons to whom the waiver was granted.

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 2004 and 2003:

	Aggregate fees billed by the Principal Accountant	
	2004	2003
	($thousands)	
Audit fees	109	156

Audit-related fees	146	218
Tax fees	184	101
All other fees	69	73
	508	548

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 audit of certain subsidiaries and financial aspects of the Registrant.

Tax Fees. Tax fees included tax planning and various taxation 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 the Sarbanes-Oxley Act of 2002.

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 relevant experience in financial matters, see the five-year history in the section "Directors and Officers" in the Registrant's Annual Information Form for the year ended December 31, 2004, which is included as Exhibit 1 to this Annual Report on Form 40-F.

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, 2004, which is filed as Exhibit 3 to this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements

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

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/ Daniel G. Belot
Name: Daniel G. Belot
Title: Vice-President Finance and Chief Financial Officer

Date: March 29, 2005

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Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2004
99.2	Comparative audited Financial Statements of the Registrant for the year ended December 31, 2004, including reconciliation to United States generally accepted accounting principles, together with the Report of the Independent Registered Chartered Accountants thereon.
99.3	Management's Discussion and Analysis of the Registrant for the year ended December 31, 2004.
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

RENEWAL ANNUAL INFORMATION FORM

2004

March 21, 2005

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GLOSSARY OF TERMS

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

Entities

Baytex, the **Corporation** or the **Company** means Bayex 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; and

Unitholders means holders of our Trust Units.

Independent Engineering

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

Sproule Report means the report dated February 28, 2005 entitled "Evaluation of the P&NG Reserves of Baytex Energy Trust as of December 31, 2004; and

NI 51-101 means National Instrument 51-101 Standards of Disclosure for Oil and Natural Gas Activities.

Securities

DRIP Plan means our distribution reinvestment plan

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

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

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 Baytex and the Trust 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 Valiant Trust Company;

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; and

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

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	Barrel
Mbbl	thousand barrels
Mmbbl	million barrels
NGLs	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.

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. 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 intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in, or incorporated by reference into, this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form or as of the date specified in the documents incorporated by reference into this Annual Information Form, as the case may be.

In particular, this Annual Information Form, and the documents incorporated by reference, contain 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 there from;
- the impact of Canadian federal and provincial governmental regulation on us relative to other oil and gas issuers of similar size;
- the goal to grow or sustain production and reserves through prudent management and acquisitions;
- the emergence of a creed of growth opportunities; and
- our ability to benefit from the combination of growth opportunities and the ability to grow through capital markets.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this Annual Information Form, 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;
- geological, technical, drilling and processing problems; 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 current estimates and assumptions that the resources and reserves described can be profitably produced in the future. The foregoing lists of factors are not exhaustive. The forward-looking statements contained in this Annual Information Form and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements. See "*Risk Factors*".

BAYTEX ENERGY TRUST

General

We are an open-end unincorporated investment trust governed by 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 the Trust.

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 equity.
(2) Baytex has a total of 1,876,004 Exchangeable Shares issued and outstanding as at December 31, 2004.
(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. In addition to such amounts, prepayments in respect of principal on the Notes may be made from time to time to us before the maturity of the 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 two-thirds 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's 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 represent 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.

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 2004 and the rate of recovery will largely be dependent on weather, Iraq's export recovery, middle-eastern conflict, and OPEC's discipline. As long as inventories remain low, the high crude oil prices the industry experienced over the past year could continue. Natural gas inventories are at more normal 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 2003 and 2004 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 the royalty trusts' ability to maintain current distribution levels.

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, and borrowing funds or otherwise obtaining credit for that purpose;

- 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 NPI payments. We make monthly cash distributions to Unitholders on our income, after expenses, if any, and any cash redemptions of Trust Units.

Cash distributions are made on the 15th day (or if such date is not a business day, on the next business day) following the end of each calendar month to Unitholders of record on or about the last business day of each such calendar month.

Our current distribution 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 excluding 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 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.

NPI

We are a party to a net profit interest 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 the 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, 2004. The effective

date of the Statement is December 31, 2004 and the preparation date of the Statement is February 28, 2005. 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") is 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. 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.

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 for the most recent 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, 2004
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	4,425.8	3,973.4	21,004.5	18,470.4	98.9	81.9	2,877.0	2,275.9	44,795.2	38,372.2
Developed Non-Producing	517.2	426.2	15,864.8	13,116.7	7.7	6.4	421.1	333.1	18,084.3	14,939.8
Undeveloped	1,772.3	1,513.9	19,843.7	17,349.5	7.9	6.3	385.7	307.5	23,322.5	20,217.8
TOTAL PROVED	6,715.3	5,913.5	56,712.9	48,936.5	114.5	94.6	3,683.8	2,916.5	86,202.0	73,529.8
PROBABLE	2,667.8	2,367.4	25,490.1	21,722.2	45.8	38.3	595.5	457.1	36,378.9	30,933.5
TOTAL PROVED PLUS PROBABLE	9,383.0	8,280.9	82,203.0	70,658.7	160.3	132.9	4,279.3	3,373.5	122,580.9	104,463.3

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT	
RESERVES CATEGORY	0% ($Million)	10% ($Million)
PROVED		
Developed Producing	893.7	677.1
Developed Non-Producing	292.6	195.4
Undeveloped	338.8	214.6
TOTAL PROVED	1,525.0	1,087.0
PROBABLE	648.8	374.4
TOTAL PROVED PLUS PROBABLE	2,173.8	1,461.4

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2004
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 Reserves	2,901	445	751	164	16	1,525
Proved Plus Probable Reserves	4,116	631	1,059	236	16	2,174

FUTURE NET REVENUE
BY PRODUCTION GROUP
AS OF DECEMBER 31, 2004
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)	111.9
	Heavy Oil (including solution gas and other by-products)	632.3
	Natural Gas (including by-products and solution gas from oil wells)	342.9
Proved Plus Probable Reserves	Light and Medium Crude Oil (excluding solution gas and other by-products)	144.0
	Heavy Oil (including solution gas and other by-products)	880.1
	Natural Gas (including by-products and solution gas from oil wells)	437.3

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2004
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	4,107.7	3,688.2	20,161.2	17,926.0	95.5	79.0	2,867.0	2,269.3	43,060.7	37,047.9
Developed Non-Producing	509.6	420.5	15,815.0	13,420.2	7.6	6.3	420.9	333.0	18,019.4	15,231.8
Undeveloped	1,768.9	1,527.9	19,898.0	17,877.5	7.8	6.2	384.6	306.6	23,359.5	20,750.6
TOTAL PROVED	6,386.2	5,636.5	55,874.2	49,223.7	111.0	91.6	3,672.5	2,908.9	84,439.6	73,030.3
PROBABLE	2,430.8	2,165.3	24,887.1	21,840.4	44.1	36.9	590.2	454.1	35,258.0	30,605.8
TOTAL PROVED PLUS PROBABLE	8,817.0	7,801.7	80,761.3	71,064.2	155.1	128.4	4,262.7	3,363.1	119,697.6	103,636.1

	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	668.6	596.3	538.5	493.6	457.9
Developed Non-Producing	180.6	148.2	125.1	107.8	94.5
Undeveloped	187.5	145.1	114.2	91.0	73.2
TOTAL PROVED	1,036.7	889.6	777.8	692.5	625.5
PROBABLE	414.8	307.2	241.5	197.1	165.3
TOTAL PROVED PLUS PROBABLE	1,451.5	1,196.8	1,019.3	889.6	790.8

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
AS OF DECEMBER 31, 2004
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 Reserves	2,358	337	787	172	25	1,037
Proved Plus Probable Reserves	3,312	467	1,118	250	25	1,452

FUTURE NET REVENUE
BY PRODUCTION GROUP

AS OF DECEMBER 31, 2004
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)	95.0
	Heavy Oil (including solution gas and other by-products)	394.1
	Natural Gas (including by-products and solution gas from oil wells)	288.7
Proved Plus Probable Reserves	Light and Medium Crude Oil (excluding solution gas and other by-products)	120.2
	Heavy Oil (including solution gas and other by-products)	535.1
	Natural Gas (including by-products and solution gas from oil wells)	363.8

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 royalties 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.

   "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.

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

4. The Alberta royalty tax credit (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. The estimates of future net revenue presented in the tables above do not represent fair market value.

Pricing Assumptions

The following sets forth the benchmark reference prices, as at December 31, 2004, 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 Baytex is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

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, 2004, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
AS OF DECEMBER 31, 2004
FORECAST PRICES AND COSTS

	OIL					
Year	WTI Cushing Oklahoma	Edmonton Par Price 40 API	Hardisty Heavy 12 API	NATURAL GAS AECO Gas Price	INFLATION RATES(1) %/Year	EXCHANGE RATE(2)
	($US/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Mmbtu)		($US/$Cdn)
2005	44.29	51.25	28.91	6.97	2.5	0.84
2006	41.60	48.03	28.12	6.66	2.5	0.84
2007	37.09	42.64	26.19	6.21	2.5	0.84
2008	33.46	38.31	25.06	5.73	2.5	0.84
2009	31.84	36.36	23.60	5.37	1.5	0.84
2010	32.32	36.91	24.12	5.47	1.5	0.84
2011	32.80	37.47	24.64	5.57	1.5	0.84
2012	33.30	38.03	25.17	5.67	1.5	0.84
2013	33.79	38.61	25.71	5.77	1.5	0.84
2014	34.30	39.19	26.26	5.87	1.5	0.84
2015	34.82	39.78	26.82	5.98	1.5	0.84
2016	35.34	40.38	27.22	6.07	1.5	0.84

Escalation Rate of 1.5% thereafter.

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, 2004, 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
AS OF DECEMBER 31, 2004
CONSTANT PRICES AND COSTS(1)

	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/Mcf)	EXCHANGE RATE(2) ($US/$Cdn)
December 31, 2004	43.45	46.53	32.97	6.78	0.8308

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.

Weighted average prices realized by us for the year ended December 31, 2004, were $6.46/Mcf for natural gas, $48.64/bbl for light crude oil and $30.32/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 (2)

	Light and Medium Crude Oil			Heavy Oil		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)
December 31, 2003	4,714	1,493	6,207	51,884	21,557	73,441
Extensions	0	0	0	4,606	1,330	5,936
Improved Recovery	21	56	77	2,591	706	3,298
Technical Revisions	(63)	13	(50)	(429)	(595)	(1,025)
Acquisitions	2,162	665	2,827	10	4	14
Dispositions	(699)	(128)	(826)	0	0	0
Economic Factors	34	66	101	(2,284)	(1,161)	(3,396)
Production	(532)	0	(532)	(7,204)	0	(7,204)
December 31, 2004	5,637	2,165	7,802	49,224	21,841	71,064

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved (Mbbl)	Probable (Mbbl)	Proved+ Probable (Mbbl)	Proved (Mmcf)	Probable (Mmcf)	Proved + Probable (Mmcf)
December 31, 2003	183	65	248	65,600	19,993	85,593
Extensions	0	0	0	3,107	2,046	5,153
Improved Recovery	0	0	0	433	16	449
Technical Revisions	7	0	7	480	3,165	3,644
Acquisitions	2,760	385	3,146	38,664	12,365	51,028
Dispositions	0	0	0	(90)	(60)	(150)
Economic Factors	(7)	5	(2)	(1,686)	(724)	(2,409)
Production	(35)	0	(35)	(14,908)	0	(14,908)
December 31, 2004	2,909	454	3,363	91,600	36,800	128,400

	Oil Equivalent (1)		
	Proved (MMboe)	Probable (MMboe)	Proved + Probable (MMboe)
December 31, 2003	67.7	26.4	94.2
Extensions	5.1	1.7	6.8
Improved Recovery	2.7	0.8	3.4
Technical Revisions	(0.4)	—	(0.4)

Acquisitions	11.4	3.1	14.5
Dispositions	(0.7)	(0.1)	(0.9)
Economic Factors	(2.4)	(1.2)	(3.7)
Production	(10.3)	—	(10.3)
December 31, 2004	73.0	30.6	103.6

Notes:

(1) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel 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.

(2) Numbers may not add due to rounding.

RECONCILIATION OF TRUST INTEREST RESERVES
EXCLUDING SOLUTION GAS AND ANY ROYALTY INTEREST

BY PRINCIPAL PRODUCT TYPE
FORECAST PRICES AND COSTS (2)

	Light and Medium Crude Oil			Heavy Oil		
	Proved)	Probable	Proved + Probable	Proved	Probable	Proved + Probable
	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)
December 31, 2003	5,159	1,649	6,808	57,568	23,606	81,174
Extensions	0	0	0	5,118	1,478	6,596
Improved Recovery	23	62	85	2,879	785	3,664
Technical Revisions	121	4	125	(477)	(661)	(1,138)
Acquisitions	2,538	777	3,315	11	4	15
Dispositions	(739)	(135)	(873)	0	0	0
Economic Factors	38	74	112	(915)	(324)	(1,240)
Production	(754)	0	(754)	(8,309)	0	(8,309)
December 31, 2004	6,386	2,431	8,817	55,874	24,887	80,761

	Natural Gas Liquids			Natural Gas including solution gas		
	Proved	Probable	Proved+ Probable	Proved	Probable	Proved + Probable
	(Mbbl)	(Mbbl)	(Mbbl)	(Mmcf)	(Mmcf)	(Mmcf)
December 31, 2003	260	95	355	81,175	24,641	105,816
Extensions	0	0	0	3,884	2,558	6,441
Improved Recovery	0	0	0	541	20	561
Technical Revisions	14	(3)	11	1,663	3,972	5,635
Acquisitions	3,449	492	3,941	46,061	13,899	59,960
Dispositions	0	0	0	(130)	(85)	(215)
Economic Factors	(10)	7	(3)	(2,108)	(904)	(3,012)
Production	(41)	0	(41)	(20,087)	0	(20,087)
December 31, 2004	3,673	590	4,263	110,999	44,101	155,100

	Oil Equivalent(1)		
	Proved	Probable	Proved + Probable
	(MMboe)	(MMboe)	(MMboe)
December 31, 2003	76.5	29.5	106.0
Extensions	5.8	1.9	7.7
Improved Recovery	3.0	0.9	3.8
Technical Revisions	(0.1)	0	(0.1)
Acquisitions	13.7	3.6	17.3
Dispositions	(0.8)	(0.1)	(1.0)
Economic Factors	(1.2)	(0.4)	(1.6)
Production	(12.5)	0	(12.5)
December 31, 2004	84.4	35.3	119.7

Notes:

(1) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOE's 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.

(2) Numbers may not add due to rounding.

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	2004 ($Million)
Estimated Future Net Revenue at Beginning of Year	793.7
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(135.1)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(15.7)
Changes in Previously Estimated Development Costs Incurred During the Period	29.2
Changes in Estimated Future Development Costs	89.3
Extensions and Improved Recovery	99.7
Acquisitions of Reserves	179.7
Dispositions of Reserves	(12.7)
Net Change Resulting from Revisions in Quantity Estimates (Technical Revisions)	(5.4)
Accretion of Discount	91.1
Miscellaneous Changes	(26.8)
Estimated Future Net Revenue at End of Year	1,087.0

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 four 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 Tangleflags and Carruthers heavy oil properties in Saskatchewan and to the Ardmore and Cold Lake heavy oil properties in Alberta. At the current prices, these well re-completions and new wells are economic. However, should oil 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.

Year	Forecast Prices and Costs		Constant Prices and Costs
	Proved Reserves ($ Million)	Proved Plus Probable Reserves ($ Million)	Proved Reserves ($ Million)
2005	84.5	97.1	82.4
2006	46.0	70.6	43.8
2007	19.7	40.3	18.3
2008	15.2	33.0	13.7
2009	1.9	1.9	1.7
Total Undiscounted (all years)	172.1	249.7	164.0
Total Discounted at 10%/year	150.3	213.3	143.9

We expect to fund the development costs of our reserves through a combination of internally generated cash flow, debt and sale of Trust Units.

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.

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.

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

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

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, 2004. The term "net", when used to describe our share of production, means the total of our working interest share before deduction of royalties owned by others. Reserve amounts are stated, before deduction of royalties, at December 31, 2004, based on forecast cost and price assumptions as evaluated in the Sproule Report (see "*Description of our Business and Operations – Disclosure of Reserves Data and Other Oil and Gas Information*"). Unless otherwise specified, gross and net acres and well count information are as at December 31, 2004. Information in respect of production is average working interest production, for the year ended December 31, 2004, except where otherwise indicated.

Our crude oil and natural gas operations are organized into two operating districts - the Heavy Oil District and the Conventional Oil and Gas District. Each district constitutes an extensive portfolio of operated properties and development prospects with considerable upside potential. We have established skilled technical teams to operate 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 of exploration, development and acquisition opportunities and improves cost efficiency.

Heavy Oil District

The Heavy Oil District accounts for approximately sixty percent of our current production, approximately three-quarters of our reserves and 50 percent of our cash flow from operations. Heavy oil operations consist largely of cold conventional production from wells with multi-zone potential. Production is generated primarily from vertical, slant and horizontal wells using progressive cavity pump technology to generate 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 ranging from 12 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. After being sold by us, the crude oil is then upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt.

In 2004, production in the Heavy Oil District averaged approximately 22,700 bbl/d of heavy oil and 9.0 mmcf/d of natural gas (24,200 boe/d). We drilled 115 gross (113.7 net) wells in the Heavy Oil District resulting in 95 gross (95.0 net) oil wells, three gross (2.2 net) gas wells, seven gross (6.5 net) stratigraphic test wells, and 10 gross (10.0 net) dry and abandoned wells, for a success rate of 91.3 percent (91.2 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 deposits. Our ability to generate relatively low-cost replacement production through conventional cold production methods allows us to optimize the timing and level of our capital investment program.

We will continue to build value through internal property development and selective acquisitions. Future heavy oil activity will focus on the development of the Seal and Ardmore properties along with continued infill drilling at the adjacent Cold Lake property and throughout the Saskatchewan properties. Company net undeveloped lands in this district totalled 344,892 acres at year-end 2004.

Ardmore: Ardmore is one of the key heavy oil development and production areas for us. Acquired in 2002 with production of 2,200 bbl/d, this property has been developed in the Sparky, McLaren and Colony formations. Average production during 2004 was approximately 4,200 bbl/d of oil and 1.0 mmcf/d of natural gas (4,400 boe/d). Current production is 3,800 bbl/d and 950 mmcf/d of natural gas (4,000 boe/d). We have applied leading-edge slotted liner production technology to improve production and increase wellbore stability. Slotted-liner wells in the area are capable of producing up to 300 bbl/d of heavy oil and continue to be used extensively for pool development projects. Twenty-six oil wells and three dry wells were drilled in the area during 2004 and 20 to 25 wells are anticipated to be drilled during 2005. During 2004, operating expenses were reduced to $5.50/bbl primarily by building a water disposal facility and conserving solution gas produced in conjunction with the heavy oil. It is expected that operating expenses will be reduced by an additional $0.75/bbl as a result of the construction of a sand disposal facility in late 2004. We also added 6,500 acres of new lands through Crown land sales in 2004 that are prospective for Colony oil pool development. Company net undeveloped lands were 39,120 acres at year-end 2004.

Cold Lake: We acquired the Cold Lake heavy oil property in 2001. This year-round drilling area is located on the Cold Lake First Nations lands, with heavy oil production generated largely from the Colony formation. Average production was 1,000 bbl/d during 2004. We drilled 12 oil wells and three dry wells in the Cold Lake area during 2004. Up to 15 new drills are anticipated during 2005. Company net undeveloped lands were 18,062 acres at year-end 2004.

Seal: The Seal property is a highly prospective property located in the Peace River oil sands area of northwest Alberta. We hold a 100 percent working interest in approximately 100 sections of land, of which 42 sections were acquired in 2004. The Seal oil deposits can be produced through horizontal well-bores at initial rates of approximately 200 bbl/d per well without the use of capital intensive steam injection methods. A seven-well stratigraphic test program completed during the first quarter of 2004 has led to our current development program on the western block of these land holdings. Two horizontal wells drilled at the end of 2004 are currently producing a total of approximately 400 bbl/d. The prospective undeveloped area of the western block of the our holdings is over 25,000 acres. During 2005, we plan to drill up to six additional stratigraphic test wells to further delineate this land block and up to 15 horizontal producers in the immediate area that are currently producing. In addition, other industry operators are currently drilling horizontal production wells on adjoining sections that will help define the productive capability of our other lands. Company net undeveloped lands in this area were 63,680 acres at year-end 2004.

Tangleflags: We 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. Provincial government regulations generally prohibit production from more than one formation at a time. As such, this property possesses long-term development potential from a considerable number of up-hole recompletion opportunities. Average production during 2004 was approximately 3,800 bbl/d of heavy oil and 1.2 mmcf/d of natural gas (4,000 boe/d). Ongoing projects in the area include up to 15 development wells during 2005, uphole recompletions after depletion of deeper producing intervals, and optimization of the solution gas gathering system. Company net undeveloped lands were 11,160 acres at year-end 2004.

Carruthers: The Carruthers property was obtained by Baytex in 1997. The property consists of separate “North” and “South” oil pools in the Cummings formation. Typical vertical oil wells initially produce approximately 40 bbl/d with ultimate recoveries of approximately 60,000 barrels of reserves. During 2004, average production was approximately 3,200 bbl/d of heavy oil and 850 mmcf/d of natural gas (3,300 boe/d). We drilled 1.2 net natural gas wells and 14 net oil wells in South Carruthers and three horizontal oil wells, in North Carruthers during 2004. This area represents a very stable production base with continued development drilling expected to total 10 to 15 wells annually. Company net undeveloped lands were 14,425 acres at year-end 2004.

Marsden/Epping/Macklin/ Silverdale: This area of Saskatchewan is characterized by low access costs and higher quality oil of 13 to 18 API gravity produced with low sand content. Initial production rates are typically 70 bbl/d and primary recovery factors can be as high as 30 percent of the original oil in place. This oil is also receptive to waterflood recovery schemes to further increase recovery. Average production in this area during 2004 was approximately 4,600 bbl/d. Twenty oil wells were drilled in 2004, increasing production to over 4,900 bbl/d by year-end. In addition, ongoing flowline installation and water disposal projects have combined to keep operating costs below $5.50/bbl. Drilling in 2005 will add up to 15 new oil wells, mostly through development of the Macklin pool. In Epping, waterflood and solution gas tie-in projects are planned for 2005. Company net undeveloped lands were 20,932 acres at year-end 2004.

Conventional Oil and Gas District

The Conventional Oil and Gas district produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2004, production averaged approximately 46 mmcf/d of natural gas and 2,200 bbl/d of hydrocarbon liquids (9,800 boe/d). In 2004, the Conventional District drilled 23 gross (20.9 net) wells resulting in four gross (4.0 net) oil wells, 14 gross (12.4 net) gas wells and five gross (4.5 net) dry and abandoned wells for a success rate of 78 percent. The Company undeveloped lands in the Conventional district were 453,166 net acres at year-end 2004. During 2004, property acquisitions at Garden Plains, Turin and Stoddart were added to the Conventional District.

Stoddart, British Columbia: The Stoddart asset acquisition was completed on December 22, 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnal, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Year-end 2004 production was approximately 11 mmcf/d and 1,600 bbl/d of hydrocarbon liquids (3,400 boe/d). We plan to drill four wells and recomplete up to seven wells in 2005 in the Stoddart area. Company net undeveloped lands were 25,343 acres at December 31, 2004.

Garden Plains/Sedalia, Alberta: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. December 2004 gas production was approximately 10 mmcf/d (1,700 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 Baytex-operated gas plants. We plan to drill four wells during 2005 in this area. Company net undeveloped lands were 77,498 acres at year-end 2004.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. December 2004 production was approximately 2 mmcf/d of natural gas and 900 bbl/d liquids (1,200 boe/d). Production comes from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and gas is processed at two outside-operated gas plants. We plan to drill up to 10 wells and recomplete 10 other wells during 2005 in the Turin area. Company net undeveloped lands were 31,335 acres at December 31, 2004.

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 2004 from this area averaged approximately 8 mmcf/d and 1,000 bbl/d hydrocarbon liquids (2,300 boe/d). We drilled eight wells in 2004 resulting in four oil wells, two gas wells and two abandoned wells and plans to drill one well in 2005. Company net undeveloped lands were 44,448 acres at year-end 2004.

Bon Accord, Alberta: This multi-zone property was acquired by Baytex in 1997. Production is from the Belly River, Viking and Mannville formations and averaged approximately 6 mmcf/d of gas and 300 bbl/d of hydrocarbon liquids or 1,300 boe/d in 2004. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. In late 2004, we drilled two gas wells (1.5 net) which will be put on production in 2005, and plans to drill one well during 2005. Company net undeveloped lands were 47,725 at year-end 2004.

Leahurst, Alberta: Production averaged approximately 8 mmcf/d (1,300 boe/d) in 2004 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 2004, we drilled five Mannville natural gas wells resulting in three gas wells and two abandonments. We also successfully recompleted nine wells for coal-bed methane production from the Horseshoe Canyon Coals during 2004. In 2005, we plan to drill 15 wells and recomplete seven wells in the Leahurst area. Company net undeveloped lands were 35,310 acres at year-end 2004.

Nina/Darwin, 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 2004 averaged approximately 5 mmcf/d (800 boe/d). Six net wells were drilled in 2004 resulting in three producing gas wells. Company net undeveloped lands were 46,203 acres at year-end 2004.

The following table indicates our average daily production from our important fields for the year ended December 31, 2004.

	Light and Medium Crude Oil (Bbl/d)	Heavy Oil (Bbl/d)	Gas (Mcf/d)
Tangleflags	—	3,794	1,212
Carruthers	—	3,155	850
Ardmore	—	4,196	993
Cold Lake	—	1,042	—
Lashburn	—	1,034	—
Silverdale	—	2,954	—
Marsden	—	1,657	—
Neilburg	—	1,049	—
Poundmaker	—	665	2,122
Red Earth	1,043	—	—
Sounding Lake	334	—	—
Bon Accord	303	—	6,392
Turin	235	—	—
Goodfish	—	—	7,493
Leahurst	—	—	7,635
Darwin/Nina	—	—	5,394
Richdale	—	—	4,381
Viking	—	—	2,289
Hamburg/Chinchaga	55	—	3,815
Tangent	—	—	3,661
Other Minor properties	202	3,157	8,640
Total	2,172	22,703	54,877

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, 2004.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	481	387.2	265	219.7	453	360.5	270	208.0
British Columbia	36	35.7	34	33.0	22	21.4	22	18.3
Saskatchewan	894	836.5	464	446.5	35	31.6	45	40.6
Total	1,411	1,259.4	763	699.2	510	413.5	337	266.9

Properties with no Attributable Reserves

The following table sets out our undeveloped land holdings as at December 31, 2004.

	Undeveloped Acres	
	Gross	Net
Alberta	716,495	552,770
British Columbia	103,400	76,895

Saskatchewan	178,025	168,393
Total	997,920	798,058

We expect that rights to explore, develop and exploit 181,765 net acres of our undeveloped land holdings, absent further action, will expire by December 31, 200**5**

Forward Contracts

For details of our material commitments to sell natural gas and crude oil which were outstanding at December 31, 2004 see Notes 16 and 17 to the Consolidated Financial Statements on pages 50 contained in our 2004 Annual Report which pages 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 1.5% per year Undiscounted ($ Million)	**Abandonment and Reclamation Costs escalated at 1.5% per year Discounted at 10%% ($ Million)**
Total as at December 31, 2004	303.0	48.0
Anticipated to be paid in 2005	2.85	2.71
Anticipated to be paid in 2006	2.89	2.50
Anticipated to be paid in 2007	2.93	2.33

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. Ongoing 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, 2004. 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 company 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 public 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 (net of certain proceeds related to our activities for the year ended December 31, 2004.

Property acquisition costs		
Proved properties	$	75,142
Unproved properties		8,744
Exploration costs		4,567
Development costs		81,171
Corporate Acquisition		111,042
Total	$	280,666

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2004.

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Oil	—	—	104	103.7
Natural Gas	—	—	16	14.1
Service	—	—	7	6.5
Dry	11	10.5	—	—
Total:	11	10.5	127	124.3

Production Estimates

The following table sets out the volume of our production estimated for the year ended December 31, 2005 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)
2005	2,400	22,000	60	1,600	36,000

Production History, Prices Received And Capital Expenditures

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 2004				Quarter Ended 2003			
	Dec.31	Sept. 30	June 30	Mar. 31	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production								
Light and Medium Crude Oil (Bbl/d)	2,786	1,890	1,952	2,058	1,982	1,989	2,167	2,969
Heavy Oil (Bbl/d)	22,490	22,083	22,927	23,322	24,400	25,123	22,816	23,278
Gas (Mmcf/d)	55.5	50.9	57.2	56.0	58.9	61.8	57.5	74.0
Combined (Boe/d)	34,525	32,454	34,411	34,709	36,195	37,412	34,574	38,580
Average Price Received								
Light and Medium Crude Oil ($/Bbl)	50.46	52.63	47.55	43.50	37.46	35.40	38.24	46.21
Heavy Oil ($/Bbl)	17.95	22.48	21,42	21,81	20.85	22.69	21.45	26.06
Gas ($/Mcf)	6.60	6.16	6.61	6.43	5.56	5.79	6.21	7.17
Combined ($/Boe)	26.38	28.04	27.92	27.63	25.23	26.69	26.97	33.32
Royalties Paid								
Light and Medium Crude Oil ($/Bbl)	8.00	6.68	6.36	6.02	5.44	5.96	7.21	8.50
Heavy Oil ($/Bbl)	4.22	5.09	3.43	3.39	2.70	3.32	3.37	4.63
Gas ($/Mcf)	1.29	1.20	1.51	1.38	1.22	1.14	1.51	1.64
Combined ($/Boe)	5.47	5.73	5.15	4.87	4.12	4.43	5.22	6.66
Production Costs								
Light and Medium Crude Oil ($/Bbl)	8.57	11.67	9.97	8.35	10.42	11.31	8.91	4.40
Heavy Oil ($/Bbl)	8.61	7.93	7.28	7.51	7.44	7.10	7.65	7.21
Gas ($/Mcf)	0.83	0.87	0.82	0.77	0.72	0.84	0.71	0.66
Combined ($/Boe)	7.63	7.43	6.78	6.78	6.74	6.75	6.77	5.91
Transportation								
Light and Medium Crude Oil ($/Bbl)	0.56	0.97	1.26	1.03	1.06	0.97	1.11	0.80
Heavy Oil ($/Bbl)	1.71	1.76	1.65	1.79	1.61	1.49	1.61	1.51
Gas ($/Mcf)	0.17	0.18	0.19	0.19	0.19	0.17	0.16	0.15
Combined ($/Boe)	1.43	1.53	1.48	1.56	1.45	1.34	1.40	1.25
Netback Received								
Light and Medium Crude Oil ($/Bbl)	33.33	33.31	29.94	28.10	20.54	17.11	21.01	32.51
Heavy Oil ($/Bbl)	3.41	7.70	9.06	9.12	9.11	10.78	8.82	12.71
Gas ($/Mcf)	4.31	3.91	4.09	4.09	3.44	3.46	3.83	4.72
Combined ($/Boe)	11.85	13.35	14.51	14.42	12.92	14.16	13.58	19.49

ADDITIONAL INFORMATION RESPECTING BAYTEX ENERGY TRUST

The following is a summary of certain provisions of the Trust Indenture. For a complete description of our indenture, reference should be made to the Trust Indenture, a copy of which has been filed on SEDAR at *www.sedar.com*.

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 either Baytex or the Trust. As holders of Trust Units, Unitholders do 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 price per Trust Unit will be a function of anticipated distributable income from Baytex and the ability of Baytex 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, exchange rates, commodity prices and our ability to acquire additional assets. Changes in market conditions may adversely affect the trading price of the Trust Units.

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

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* – Share Capital" below.

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 and the size of the capital budget, it is expected that 30% to 40% of the cash available for distribution will fund a portion of our annual capital expenditure program, including both exploitation expenditures and minor property acquisitions, but excluding major acquisitions.

Pursuant to various agreements with Baytex's lenders, we are is 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.

The following is a summary of the distributions paid or declared by us from inception in September of 2003 to March 15, 2005.

For the Month Ended	Distributions per Unit	Payment Date
September 30, 2003	$ 0.15	October 15, 2003
October 31, 2003	$ 0.15	November 15, 2003
November 30, 2003	$ 0.15	December 15, 2003
December 31, 2003	$ 0.15	January 15, 2004
January 31, 2004	$ 0.15	February 16, 2004
February 29, 2004	$ 0.15	March 15, 2004
March 31, 2004	$ 0.15	April 15, 2004
April 30, 2004	$ 0.15	May 17, 2004
May 31, 2004	$ 0.15	June 15, 2004
June 30, 2004	$ 0.15	July 15, 2004
July 31, 2004	$ 0.15	August 16, 2004
August 31, 2004	$ 0.15	September 15, 2004
September 30, 2004	$ 0.15	October 15, 2004
October 31, 2004	$ 0.15	November 15, 2004
November 30, 2004	$ 0.15	December 15, 2004
December 31, 2004	$ 0.15	January 17, 2005
January 31, 2005	$ 0.15	February 15, 2005
February 28, 2005	$ 0.15	March 15, 2005

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 50% 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, 2004, approximately 31% 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. Our 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 Tax Act 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 since October 1998.
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	Independent businessman since May 2002; prior thereto Chairman of the Board of Ventus Energy Ltd. since January 1999; prior thereto Chief Executive Officer of Marathon Oil Canada Ltd. since August 1998; prior thereto President and Chief Executive Officer of Tarragon Oil and Gas Limited.
Naveen Dargan (1) (2) Calgary, Alberta	Director	Independent businessman since June 2003; prior thereto Senior Managing Director of Raymond James Ltd. and predecessor companies.

Name and Municipality Of Residence	Position with Baytex	Principal Occupation
Dale O. Shwed(1) (3)(6) Calgary, Alberta	Director	President and Chief Executive Officer of Crew Energy Inc. since September 2003; prior thereto President and Chief Executive Officer of Baytex.

Daniel G. Belot Calgary, Alberta	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer of Baytex since September 2003; prior thereto Manager, Investor Relations, Pengrowth Energy Trust from 2001 to 2003; prior thereto, Corporate and Investment Banker with Scotia Capital.
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. from 2000 to 2003; prior thereto President and CEO of Enercap Corporation, a private investment company.
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. since November 2000; prior thereto Vice President, Marketing of Ranger Oil Limited.
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 2002 to 2004; prior thereto Vice President, Engineering of Dominion Exploration & Production Inc. from January 2002 to October 2002; prior thereto Team Leader, Jonah/Pinedale asset area of AEC Oil & Gas (USA) Inc. from 2000 to 2002; prior thereto Division Manager, Engineering/New Ventures of Santa Fe Snyder Corporation.
Shannon M. Gangl Calgary, Alberta	Corporate Secretary	Partner, Burnet, Duckworth & Palmer LLP.

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. John 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, 2005, the directors and executive officers of Baytex, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 461,717 Trust Units, or approximately 0.70% of the issued and outstanding Trust Units. In addition, as at February 28, 2005, the directors and executive officers of Baytex, as a group, beneficially owned, directly or indirectly, exercised control or direction over, 605,129 Exchangeable Shares (approximately 33% of the issued and outstanding Exchangeable Shares).

Corporate Cease Trade Orders or Bankruptcies

No director, officer or promoter of Baytex has, within the last 10 years, been a director, officer or promoter of any reporting issuer that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the company access to any statutory exemption for a period of more than 30 consecutive days or was declared a bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver-manager or trustee appointed to hold the assets of that person other than as set forth herein.

Penalties or Sanctions

No director, officer or promoter of Baytex, within the last 10 years, has been subject to any penalties or sanctions imposed by a court or securities regulatory authority relating to trading in securities, promotion or management of a publicly traded issuer or theft or fraud.

Personal Bankruptcies

No director, officer or promoter of Baytex, or a shareholder holding sufficient securities of the Trust to affect materially the control of the Trust, or a personal holding company of any such persons, has, within the last 10 years, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or being subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold the assets of the individual.

Conflicts of Interest

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, 2004, Baytex employed 102 head office employees and 13 field office employees.

AUDIT COMMITTEE

The Audit Committee of Baytex is composed of the following members:

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.

Dale O. Shwed	Yes	Yes	President and Chief Executive Officer of Crew Energy Inc. since September 2003; prior thereto President and Chief Executive Officer of Baytex.

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.

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 2004 and 2003:

	Aggregate fees billed	
	2004	2003
	($thousands)	
Audit fees	109	156
Audit-related fees	146	218
Tax fees	184	101
All other fees	69	73
	508	548

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.

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

BAYTEX SHARE CAPITAL

Baytex is authorized to issue an unlimited number of common shares and an unlimited number of Exchangeable Shares. As of the date hereof, there are 1,852,744 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 holder 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, 2004, 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 number of 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 September 2, 2005, redeem all but not less than all outstanding Exchangeable Shares for thre redemption price per Exchangeable Share at the last business day prior to the redemption date, to be satisfied by the delivery of Trust Units;

(c) 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

(d) 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:

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

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

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

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

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

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

The Support Agreement also provides that, as long as any outstanding Exchangeable Shares are owned by any person or entity other than us or any of our subsidiaries or affiliates, we will, unless approval to do otherwise is obtained from the holders of Exchangeable Shares, remain the direct or indirect beneficial owner collectively of more than 50% 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 are listed for trading on the Toronto Stock Exchange under the symbol “BTE.UN”. 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			
September	10.85	9.19	9,992,166
October	10.65	9.49	13,469,910
November	10.64	9.98	7,380,404
December	10.89	9.97	10,131,182
2004			
January	11.45	10.60	8,866,915
February	10.82	9.78	11,503,106
March	11.32	10.25	14,408,162
April	12.32	11.00	7,312,078
May	12.60	11.51	10,079,917
June	12.32	11.29	4,590,663
July	12.65	11.95	3,819,217
August	12.90	11.90	4,912,537
September	13.13	11.65	4,964,218
October	14.00	12.79	9,654,989
November	13.70	12.60	7,049,582
December	13.42	12.61	6,091,424

	Price Range		Volume Traded
	High ($)	Low ($)	
2005			
January	13.26	12.42	6,261,488
February .	15.07	13.25	11,885,861

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 senior officers of the Trust, nominees for director, any Unitholder who beneficially owns more than 10% of the Trust Units or any known associate or affiliate of such persons in any transaction since the beginning of the Trust’s last completed financial year or in any proposed transaction which has materially affected or would materially affect the Trust.

AUDITORS, TRANSFER AGENT AND REGISTRAR

Our Independant Registered Chartered Accountants are Deloitte & Touche LLP, Calgary, Alberta.

Valiant Trust Company, at its principal office in Calgary, Alberta and through its co-agent, Equity Transfer Services Inc., at its principal office in Toronto, Ontario is the transfer agent and registrar for the Trust Units.

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 principals of Sproule had 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. The auditors of the Trust are Deloitte & Touche, LLP, Independent Registered Chartered Accountants, Calgary, 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.

INDUSTRY CONDITIONS

General

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

Pricing and Marketing Oil and Natural Gas

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

From time to time pipeline capacity limits the ability to produce and market crude oil and natural gas production although pipeline expansions are ongoing.

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. The agreement also contemplates clearer disciplines on regulators to ensure fair implementation of any regulatory changes and to minimize disruption of contractual arrangements, which is important for Canadian natural gas exports.

Provincial Royalties and Incentives

In addition to federal regulation, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiations between the mineral owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Crown royalties are determined by governmental regulation and are generally calculated as a percentage of the value of the gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date and the type or quality of the petroleum product produced.

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

In the Province of Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m^3 and 25% at prices at and above $210 per m^3. The ARTC rate is 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 a corporation already claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Crude oil and natural gas royalty programs for specific wells and royalty reductions reduce the amount of Crown royalties paid by our operating entities to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

Land Tenure

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

Environmental Regulation

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

Environmental legislation in the Province of Alberta has been consolidated into the Alberta Environmental Protection and Enhancement Act (the "APEA"), which came into force on September 1, 1993. The APEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties. We are committed to meeting its responsibilities to protect the environment wherever it operates and anticipates 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 APEA and similar legislation in other jurisdictions in which it operates. We believe that we are in material compliance with applicable environmental laws and regulations. We also believe that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In December 2002, the Government of Canada ratified the Kyoto Protocol and it became legally binding on February 16, 2005. This protocol calls for Canada to reduce its green house gas emissions to 6% below 1990 levels during the period between 2008 and 2012. See also *"Risk Factors – Kyoto Protocol"*.

RISK FACTORS

The following is a summary of certain risk factors relating to our business. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this Annual Information Form.

Dependence on Baytex

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

Exploitation and development risks are due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. These risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which we have existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods, and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three-dimensional seismography, reservoir simulation studies and horizontal drilling have been used by us and will be used by us to improve our ability to find, develop and produce oil and natural gas.

Operations

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. We have both safety and environmental policies in place to protect our operators and employees, as well as to meet the regulatory requirements in those areas where we operate. 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.

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.

Oil and Natural Gas Prices

The price of oil and natural gas will fluctuate and price and demand are factors beyond our control. Such fluctuations will have a positive or negative effect on the revenue to be received by it. Such fluctuations will also have an effect on the acquisition costs of any future oil and natural gas properties that Baytex may acquire. As well, cash distributions from us will be highly sensitive to the prevailing price of crude oil and natural gas.

Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by us will be affected by numerous factors beyond its control. These factors include demand for oil and natural gas, market fluctuations, the proximity and capacity of oil and natural gas pipelines and processing equipment and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, importing and exporting of oil and natural gas.

Capital Investment

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

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.

Reserves

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.

Competition

The industry is highly competitive in the acquisition of exploration prospects and the development of new sources of production and the sale of oil and natural gas.

Environmental Concerns

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.

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.

Depletion of Reserves

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

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.

Distributions

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.

Mutual Fund Trust Status

It is intended that we will continue to qualify as a mutual fund trust for the purposes of the *Income Tax Act* (Canada) (the "Tax Act"). We may not, however, always be able to satisfy any future requirement for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- Where at the end of any month a registered retirement savings plan ("RRSP"), registered retirement income fund ("RRIF"), registered education savings plan ("RESP") or deferred profit sharing plan ("DPSP") (collectively, "Exempt Plans") holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI. 1 of the Tax Act equal to 1 percent of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. An RRSP or RRIF holding Trust Units that are not qualified investments would become taxable on income attributable to the Trust Units while they are not qualified investments (including the entire amount of any capital gain arising on a disposition of the non-qualified investment). RESPs which hold Trust Units that are not qualified investments may have their registration revoked by the Canada Customs and Revenue Agency.

- Trust Units would become foreign property for Exempt Plans upon the Trust ceasing to be a mutual fund trust.

- The Trust would be taxed on certain types of income distributed to Unitholders, including income generated by the royalty held by the Trust. 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.

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

- Trust Units would become taxable Canadian property. As a result, non-resident Unitholders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.

In addition, we may take certain measures in the future to the extent we believe such measures are necessary to ensure we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units.

Non-resident Ownership of 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.

Income Tax Matters

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.

Nature of Trust Units

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.

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*".

Unitholder 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 ust. 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.

Permitted Investments

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.

Regulatory Matters

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.

Kyoto Protocol

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.

Conflicts of Interest

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.

ADDITIONAL INFORMATION

Additional information including remuneration of directors and officers of Baytex, principal holders of the Trust Units, Exchangeable Share and rights to purchase Trust Units, will be contained in our Information Circular which relates to the Annual and Special Meeting of Unitholders to be held on May 11, 2005, and additional financial information is provided in our consolidated financial statements and management discussion and analysis of financial results for the year ended December 31, 2004 which are attached hereto as Appendix D and which have been filed on SEDAR at *www.sedar.com*.

The Trust will provide to any person, upon request to the Chief Financial Officer of the Corporation:

1. when the securities of the Trust are in the course of a distribution pursuant to a preliminary short form prospectus or a short form prospectus:

   (a) one copy of the Annual Information Form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

   (b) one copy of the comparative financial statements of the Trust for its most recently completed fiscal period for which financial statements have been filed, together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Trust that have been filed, if any, for any period after the end of its most recently completed financial year;

   (c) one copy of the Information Circular of the Trust in respect of its most recent annual and special meeting of Unitholders; and

   (d) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and which are not required to be provided under items (a) to (c) above; or

2. at any other time, one copy of any documents referred to in items (1)(a), (b) and (c) above, provided that the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

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, 2004 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, 2004 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) "*Daniel G. Belot*"
Daniel G. Belot
Vice President, Finance and Chief Financial Officer

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

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

February 28, 2005

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, 2004. The reserves data consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2004 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, 2004 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, 2004, 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 28, 2005	Canada	—	1,019.3	—	1,019.3

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. 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 28, 2005

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

6. 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").

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

8. 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

9. 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.

10. 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.

11. 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.

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

13. The Committee shall meet with the external 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

14. 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.

15. 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.

16. 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.

17. 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.

18. 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.

19. 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.

20. 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.

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

22. 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.

23. 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.

24. 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.

25. 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

Friday, March 25, 2005
5:05 PM

Consolidated Financial Statements of

BAYTEX ENERGY TRUST

December 31, 2004

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 registered chartered accountants 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.

(signed) "Raymond T. Chan, CA"
President and Chief Executive Officer
Baytex Energy Ltd.
March 22, 2005

(signed) "Daniel G. Belot"
Vice President, Finance and Chief Financial Officer
Baytex Energy Ltd.

Report of Independent Registered Chartered Accountants
To the Trustee and the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2004 and 2003 and the consolidated statements of operations and accumulated income (deficit) and of 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, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The Corporation 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 Corporation's internal control over financial reporting. Accordingly, we express no such opinion.

On March 7, 2005, 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 20, Differences Between Canadian and United States Generally Accepted Accounting Principles.

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

Calgary, Alberta, Canada

March 7, 2005 (except as to note 20, which is

as at March 22, 2005)

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 Note 20 to the financial statements and when there are changes in accounting principles that have a material effect on the comparability of the Trust's consolidated financial statements and changes in accounting principles that have been implemented in the consolidated financial statements, such as described in Note 3 to the consolidated financial statements. Our report to the Unitholders, dated March 7, 2005 (except as to note 20, which is as at March 22, 2005) is expressed in accordance with Canadian reporting standards which do not require a reference to such conditions and events and such changes in accounting principles 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, 2005 (except as to note 20, which is as at March 22, 2005)

Baytex Energy Trust
Consolidated Balance Sheets
As at December 31, 2004 and 2003
(thousands of Canadian dollars)

	2004	2003 (note 3)
Assets		
Current assets		
Cash and short-term investments	$ —	$ 53,731
Accounts receivable	41,154	48,608
Crude oil inventory	7,299	5,900
	48,453	108,239
Deferred charges and other assets	6,491	7,764
Petroleum and natural gas properties (note 5)	1,009,933	866,637
Goodwill (note 4)	39,259	—
	$ 1,104,136	$ 982,640
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 72,976	$ 80,126
Distributions payable to unitholders	9,981	9,123
Bank loan (note 6)	161,444	—
Financial derivative contracts (note 16)	9,513	—
	253,914	89,249
Long-term debt (note 7)	216,583	232,562
Asset retirement obligation (note 8)	73,297	55,996
Future income taxes (note 13)	164,909	170,952
	708,703	548,759
Non-controlling interest (note 10)	12,962	25,705
Unitholders' Equity		
Unitholders' capital (note 9)	515,728	449,403
Contributed surplus	7,494	224
Accumulated distributions	(146,445)	(33,382)
Accumulated income (deficit)	5,694	(8,069)
	382,471	408,176
	$ 1,104,136	$ 982,640

Commitments and contingencies (note 17)

See accompanying notes to the consolidated financial statements.

On behalf of the Board of Baytex Energy Ltd.

(signed) "**Naveen Dargan**"
Director
Baytex Energy Ltd.

(signed) "**W. A. Blake Cassidy**"
Director
Baytex Energy Ltd.

Baytex Energy Trust
Consolidated Statements of Operations and Accumulated Income (Deficit)
Years Ended December 31, 2004 and 2003
(thousands of Canadian dollars, except per unit data)

	2004	2003 (note 3)
Revenue		
Petroleum and natural gas sales (note 3)	$ 420,400	$ 403,022
Royalties	(65,988)	(67,175)
Realized loss on financial derivatives	(78,124)	(33,777)
Unrealized gain on financial derivatives	597	—
	276,885	302,070
Expenses		
Operating	89,078	86,034
Transportation (note 3)	18,714	17,841
General and administrative	15,243	8,927
Unit based compensation (note 11)	7,736	739
Interest (note 7)	19,412	23,548
Costs on redemption and exchange of notes (note 7)	—	44,771
Foreign exchange gain (note 7)	(15,979)	(52,101)
Depletion, depreciation and accretion	160,808	123,137
Reorganization costs (note 18)	—	18,851
	295,012	271,747
Income (loss) before income taxes and non-controlling interest	(18,127)	30,323
Income taxes (recovery) (note 13)		
Current	9,000	9,663
Future	(41,237)	(14,516)
	(32,237)	(4,853)
Income before non-controlling interest	14,110	35,176
Non-controlling interest (note 10)	(347)	668
Net income	13,763	35,844
Accumulated deficit, beginning of year, as previously reported	(351)	(38,489)
Accounting policy change for non-controlling interest (note 3)	529	—
Accounting policy change for asset retirement obligations (note 3)	(8,247)	(5,424)
Accumulated deficit, beginning of year, as restated	(8,069)	(43,913)
Accumulated income (deficit), end of year	$ 5,694	$ (8,069)
Net income per trust unit (note 12)		
Basic	$ 0.22	$ 0.66
Diluted	$ 0.21	$ 0.62

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Consolidated Statements of Cash Flows
Years Ended December 31, 2004 and 2003
(thousands of Canadian dollars)

	2004	2003 (note 3)
Cash provided by (used in):		
Operating activities		
Net income	$ 13,763	$ 35,844
Items not affecting cash:		
Unit based compensation (note 11)	7,736	739
Amortization of deferred charges	11,171	1,027
Costs on redemption and exchange of notes (note 7)	—	44,771
Unrealized foreign exchange gain	(15,979)	(52,101)
Depletion, depreciation and accretion	160,808	123,137
Unrealized gain on financial derivatives (note 16)	(597)	—

Future income taxes (recovery)	(41,237)	(14,516)
Non-controlling interest (note 10)	347	(668)
	136,012	138,233
Change in non-cash working capital (note 14)	3,589	(8,060)
Asset retirement expenditures	(2,739)	(880)
Decrease in deferred charges and other assets	212	211
Decrease in deferred credits	—	(2,213)
	137,074	127,291
Financing activities		
Redemption of senior secured notes (note 7)	—	(89,950)
Increase in bank loan	161,444	—
Increase in deferred charges and other assets	—	(7,425)
Issue of trust units (note 9)	44,505	61,525
Payments of distributions	(112,074)	(24,259)
Issue of common shares (note 18)	—	37,049
	93,875	(23,060)
Investing activities		
Petroleum and natural gas property expenditures	(184,065)	(185,876)
Corporate acquisition (note 4)	(111,042)	—
Disposal of petroleum and natural gas properties	14,441	137,493
Change in non-cash working capital (note 14)	(4,014)	(6,215)
	(284,680)	(54,598)
Change in cash and short-term investments during the year	(53,731)	49,633
Cash and short-term investments, beginning of year	53,731	4,098
Cash and short-term investments, end of year	$ —	$ 53,731

See accompanying notes to the consolidated financial statements.

Baytex Energy Trust
Notes to the Consolidated Financial Statements
Years Ended December 31, 2004 and 2003
(all tabular amounts in thousands of Canadian dollars, except per unit amounts)

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a wholly owned subsidiary of the Trust (note 18).

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 ("GAAP") as described in note 2. Material differences between Canadian GAAP and U.S. GAAP are disclosed in Note 20.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned 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.

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.

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

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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.

Flow-through Shares

The Company had financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the book value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company recorded the gross book value of the expenditures and a future tax liability for the tax benefits renounced to subscribers.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 11. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the consolidated financial statements for unexercised 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 or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in income in the period of change 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.

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

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. 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.

3. CHANGES IN ACCOUNTING POLICIES

Unit-Based Compensation

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. For the year ended December 31, 2003, compensation expense of $0.22 million was recorded for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. For the year ended December 31, 2003, compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (note 18).

Full Cost Accounting

In 2003, the CICA issued Accounting Guideline 16, Oil and Gas Accounting – Full Cost (AcG-16). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies the ceiling test calculation applied by the Trust. The ceiling test was changed to 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 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. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust (note 17):

	2004	2005	2006	2007	2008
WTI ($US/bbl)	29.63	26.80	25.76	26.14	26.53
AECO ($CDN/mcf)	6.03	5.36	4.80	4.91	4.98

Asset Retirement Obligations

Effective January 1, 2004, the Trust adopted the CICA Section 3110, "Asset Retirement Obligations". This section requires recognition of 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 in which the actual costs were incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative year ended December 31, 2003 decreased by $2.8 million, net of future income tax of $0.8 million. At December 31, 2003 the asset retirement obligations balance increased by $32.5 million to $56.0 million, the petroleum and natural gas assets balance increased by $19.2 million to $862.3 million and the future tax liability decreased by $5.0 million to $169.3 million. The opening 2003 accumulated deficit increased by $5.4 million (net of future income tax of $0.8 million). There was no impact on cash flow as a result of adopting this policy (note 8).

Financial Derivative Contracts

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 "Hedging Relationships" (AcG-13) for accounting for derivative contracts. This guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, 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 derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC 128) also became effective. EIC 128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the consolidated balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC-128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded 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 from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of $0.6 million in the consolidated statement of operations (note 16).

Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the year ended December 31, 2004 both increased by $18.7 million (2003 – $17.8 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

Non-controlling interest

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, "Exchangeable Securities Issued by Subsidiaries of Income Trusts" (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. 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. The presentation of the exchangeable shares at December 31, 2003 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of Unitholders' Equity.

As a result of the adoption of EIC 151, net income was reduced in 2004 by $0.35 million for the non- controlling interest's share of income and was increased in 2003 by $0.67 million for the non- controlling interest's share of the loss from the date of the Arrangement. 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. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a $15.0 million increase in petroleum and natural gas properties (December 2003 - $4.3 million), a $5.7 million increase in future income taxes (December 2003 - $1.6 million) and a $10.9 million increase in unitholders' capital (December 2003 - $2.8 million).

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. The Company has not yet completed its final valuation of the assets acquired and liabilities assumed and, therefore, the purchase price allocation may be subject to change. Subsequent to the acquisition, the private company was amalgamated with the Company.

Petroleum and natural gas properties	$	109,777
Goodwill		39,259
Working capital		1,447
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 $39.3 million was determined based on the excess of the total consideration paid less the value assigned to the identifiable assets and liabilities including the future income tax liability.

5. PETROLEUM AND NATURAL GAS PROPERTIES

	As at December 31,	
	2004	2003 (note 3)
Petroleum and natural gas properties	**$ 2,342,514**	$ 2,042,749
Accumulated depletion and depreciation	**(1,332,581)**	(1,176,112)
	$ 1,009,933	$ 866,637

In calculating the depletion and depreciation provision for 2004, $61.7 million (2003 - $51.1 million) of costs relating to undeveloped properties and materials and supplies of $3.7 million (2003 - $4.0 million) were excluded from costs subject to depletion and depreciation. During 2003, $4.4 million of corporate expenses relating to exploration and development activities were capitalized. No corporate 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, 2004 using the following benchmark reference prices for the years 2005 to 2009 adjusted for commodity differentials specific to the Trust (note 17):

	2005	2006	2007	2008	2009
WTI ($US/bbl)	44.29	41.60	37.09	33.46	31.84
AECO ($CDN/mcf)	6.97	6.66	6.21	5.73	5.37

The prices and costs subsequent to 2009 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 and probable reserves 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 17) 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

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charge over all of the Company's assets. At December 31, 2004 a total of $161.4 million had been drawn under the credit facilities.

7. LONG-TERM DEBT

	As at December 31, 2004	As at December 31, 2003
10.5% senior subordinated notes (US$247,000)	**$ 297**	$ 319
9.625% senior subordinated notes (US$179,699,000)	**216,286**	232,243
	$ 216,583	$ 232,562

Senior Subordinated Notes

On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old 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.

On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities. In November 2003, 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.

Senior Secured Notes

On November 13, 1998, the Company issued US$57 million of senior secured notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. In May 2003, the Company redeemed the outstanding senior secured notes for a total cash payment of $90 million, resulting in a cost of $4.7 million on the redemption.

Interest Expense

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

	2004	2003
Bank loan	**$ 2,256**	$ 675
Amortization of deferred charges	**1,060**	1,027
Long-term debt	**16,096**	21,846
Total interest	**$ 19,412**	$ 23,548

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8. ASSET RETIREMENT OBLIGATIONS

	As at December 31, 2004	As at December 31, 2003 (note 3)
Balance, beginning of the year	**$ 55,996**	$ 52,244
Liabilities incurred	**4,623**	4,010
Liabilities settled	**(2,739)**	(880)

Acquisition of liabilities		**12,797**		—
Disposition of liabilities		**(1,722)**		(3,335)
Accretion		**4,342**		3,957
Balance, end of the year	**$**	**73,297**	$	55,996

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 55 years with the majority of costs incurred between 2029 and 2060. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2004 is $189 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 1.5 percent.

9. UNITHOLDERS' CAPITAL

Trust Units

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53,304,858 trust units and 4,732,326 exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company (notes 10 and 18).

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. On December 12, 2003, the Trust issued 6,500,000 trust units at $10.00 per unit for gross proceeds of $65 million pursuant to a prospectus.

Trust Units	**Number of units**	**Amount**
Issued September 2, 3003 pursuant to Plan of Arrangement (note 18)	53,305	$ 377,419
Issued on conversion of Exchangeable Shares	1,016	9,944
Unit-based compensation	—	515
Issued for cash, net of expenses	6,500	61,525
Balance December 31, 2003 (restated – note 3)	60,821	449,403
Issued on conversion of Exchangeable Shares	1,994	21,222
Issued on exercise of trust unit rights (1)	113	1,472
Issued pursuant to distribution reinvestment program	10	131
Issued for cash, net of expenses	3,600	43,500
Balance December 31, 2004	66,538	$ 515,728

(1) Includes compensation expense transferred from contributed surplus.

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. Trust units purchased from treasury under the DRIP will be issued at a 5% discount from the weighted average closing price of the trust units on the Toronto Stock Exchange. 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

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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.

10. 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 of the five-day trading period ending on the record date. The exchange ratio at December 31, 2004 was 1.21472 trust units per exchangeable share (2003 - 1.04530 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 or decrease to the non-controlling interest on the balance sheet.

Non-controlling Interest	**Number of Exchangeable Shares**	**Amount**
Issued September 2, 2003 pursuant to Plan of Arrangement (note 18)	4,732	$ 33,507
Exchanged for trust units	(1,007)	(7,134)
Non-controlling interest in net loss	—	(668)
Balance December 31, 2003 (restated – note 3)	3,725	25,705
Exchanged for trust units	(1,849)	(13,090)
Non-controlling interest in net income	—	347
Balance December 31, 2004	1,876	$ 12,962

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. During the year ended December 31, 2004, the adoption of EIC 151 resulted in a $15.0 million increase in petroleum and natural gas properties (December 2003 - $4.3 million), a $5.7 million increase in future income taxes (December 2003 - $1.6 million) and a $10.9 million increase in unitholders' capital (December 2003 - $2.8 million).

11. TRUST UNIT RIGHTS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. A total of 5,800,000 Trust Unit Rights are reserved for issue under the Plan. Trust Unit Rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

The Trust Unit Rights Incentive Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions provided a certain threshold return on assets is met. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future trust unit prices, production of oil and natural

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gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements. The accounting for unit-based compensation results in compensation expense for year ended December 31, 2004 of $7.7 million (2003 - $0.22 million).

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

	Number of Rights	Weighted average exercise price (1)
Initial grant September 9, 2003	2,593	$ 10.23
Granted	380	$ 9.60
Cancelled	(118)	$ 10.23
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

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

The following table summarizes information about the unit rights outstanding at December 31, 2004:

Range of Exercise Prices	Number Outstanding at December 31, 2004	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2004	Weighted Average Exercise Price
$7.21 to $8.49	2,239	3.7	$ 8.34	680	$ 8.34
$8.50 to $9.99	176	4.1	$ 9.12	—	—
$10.00 to $11.49	361	4.6	$ 11.30	—	—
$11.50 to $13.25	761	4.9	$ 12.60	—	—
$7.21 to $13.25	3,537	4.0	$ 9.60	680	$ 8.34

12. 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 at year-end, converted at the year-end exchange ratio, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

	2004	2003
Weighted average number of units outstanding, basic	62,574	53,995
Trust units issuable on conversion of exchangeable shares	2,635	1,535
Dilutive effect of trust unit incentive rights	473	990
Weighted average number of units outstanding, diluted	65,682	56,520

The dilutive effect of trust unit incentive rights above did not include 3.1 million trust unit rights (2003 - 2.7 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 and not yet recognized.

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13. INCOME TAXES (RECOVERY)

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

	2004	2003 (note 3)
Income (loss) before income taxes and non-controlling interest	$ (18,127)	$ 30,323
Expected income taxes (recovery) at the statutory rate of 40.57% (2003 – 42.5%)	$ (7,354)	$ 12,887
Increase (decrease) in taxes resulting from:		
Crown royalties	18,802	21,451
Resource allowance	(9,663)	(18,334)
Alberta royalty tax credit	(203)	(213)
Net income of the Trust	(46,469)	(14,191)
Non-taxable portion of foreign exchange gain	(3,241)	(11,074)
Effect of change in tax rate	(10,324)	(5,462)
Effect of change in opening tax pool balances	8,711	—
Effect of change in valuation allowance	5,194	—
Unit based compensation	2,949	314
Other	361	106
Large corporation tax and provincial capital tax	9,000	9,663
Provision for (recovery of) income taxes	$ (32,237)	$ (4,853)

The components of future income taxes are as follows:

	As at December 31,	
	2004	2003 (note 3)
Future income tax liabilities:		
Capital assets	$ 193,584	$ 209,425
Other	12,853	2,560
Future income tax assets:		
Asset retirement obligation	(26,072)	(21,239)
Reorganization costs	(12,206)	(19,794)
Loss carry-forward	(3,250)	—
Future income taxes	$ 164,909	$ 170,952

14. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

	2004	2003
Current assets	$ 6,055	$ (1,840)
Current liabilities	(5,630)	(12,435)
	$ 425	$ (14,275)
Changes in non cash working capital related to:		
Operating activities	$ 3,589	$ (8,060)
Investing activities	(4,014)	(6,215)
	$ 425	$ (14,275)

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

	2004	2003
Interest	$ 21,096	$ 24,449
Current income taxes	$ 17,485	$ 12,557

15. FINANCIAL INSTRUMENTS

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, 2004, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2003 - 105 percent).

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.

16. 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, 2004, the Trust had derivative contracts for the following:

	Period	Volume	Price	Index
Oil				
Price collar	Calendar 2005	3,000 bbl/d	US$35.00 – $42.40	WTI
Price collar	Calendar 2005	2,000 bbl/d	US$35.00 – $42.50	WTI
Price collar	Calendar 2005	1,000 bbl/d	US$35.00 – $42.70	WTI
Price collar	Calendar 2005	2,000 bbl/d	US$35.00 – $42.75	WTI

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

As discussed in note 3, under the new guideline for hedge accounting, the Trust's financial derivative contracts for oil collars do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has been recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded 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 from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of $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.

17. 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, 2004, there are outstanding letters of credit aggregating $2.2 million issued as security for performance under certain contracts.

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.

18. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement (note 1), the Company transferred to Crew a portion of the Company's producing and exploratory petroleum and natural gas assets. As this was a related party transaction, assets and liabilities were transferred at net book value as follows:

Petroleum and natural gas assets and equipment	$ 21,244
Future income tax asset	3,278
Total assets transferred	24,522
Provision for future site restoration	(559)
Net assets transferred and reduction in share capital	$ 23,963

Reorganization costs of $18.9 million were expensed in the consolidated statements of operations as a result of the Plan of Arrangement.

Under the Plan of Arrangement, shareholders of the Company received one unit of the Trust or one exchangeable share and one-third of a share of Crew for each common share held.

Common shares of Baytex Energy Ltd.	Number of shares	Amount
Balance December 31, 2002	52,819	$ 398,176
Flow-through shares issued	103	810
Future tax related to flow-through shares	—	(336)
Exercise of stock options	5,115	36,239
Transfer of assets under Plan of Arrangement	—	(23,963)
Balance September 2, 2003 prior to Plan of Arrangement	58,037	410,926
Trust units issued (note 9)	(53,305)	(377,419)
Exchangeable shares issued (note 10)	(4,732)	(33,507)
Balance December 31, 2003	—	$ —

The Company had a stock option plan prior to the Plan of Arrangement. The outstanding stock options of the Company were exercised or cancelled as follows:

	Number of options	Weighted average exercise price

Balance December 31, 2002	5,126	$ 6.98
Granted	121	$ 9.28
Exercised	(5,115)	$ 7.07
Cancelled	(132)	$ 5.44
Balance December 31, 2003	—	—

The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Compensation expense of $0.52 million was recorded for all stock options granted by the Company on or after January 1, 2003, with a corresponding amount recorded as trust units on exercise of the options, with expenses in the first and second quarters increased by $0.32 million and $0.20 million, respectively. Accordingly, quarterly net income in such quarters previously reported as $32.9 million and $41.8 million would be revised to $32.6 million and $41.6 million, respectively. There were no changes to the expenses or the net loss of the third quarter of 2003.

Compensation expense for options granted during 2003 was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option. For options granted prior to January 1, 2003, the pro forma income impact of related stock-based compensation expense is as follows:

	Year Ended December 31, 2003
Net income as reported (restated – see note 3)	$ 35,844
Stock-based compensation expense	(5,522)
Pro forma	$ 30,322
Net income per unit	
Basic as reported	$ 0.66
Pro forma	$ 0.56
Diluted as reported	$ 0.62
Pro forma	$ 0.52

The weighted average fair market value of options granted during the year ended December 31, 2003 was $4.21 per option. The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk free interest rate of 4.5 percent; expected life of four years; and expected volatility of 52 percent.

19. SUBSEQUENT EVENT

In January 2005, the Company entered into agreements to collar the exchange rate on US$9 million per month at average $CDN/$US rates between $1.2168 and $1.2500.

20. 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 2004 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 amortization will differ in subsequent years.

(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. In prior years, the Trust accounted for its trust units under U.S. GAAP as a component of permanent Unitholders’ Equity. This accounting was based on the assumption that the redemption feature embedded in the Trust Units was sufficiently restrictive to avoid classification as temporary equity under U.S. GAAP. In 2004, the Trust has concluded that the restrictions on redemption are not substantive enough to avoid classification as temporary equity under U.S. GAAP, in accordance with EITF D-98, and the trust units must be presented as Temporary Equity and carried on the consolidated balance sheets at their redemption value. As a result, in 2004 the Trust has retroactively restated its trust units as Temporary Equity on its consolidated

balance sheets.

In applying this retroactive restatement the Trust has recorded Temporary Equity in the amount of $878.8 million for 2004 and $702.1 million for 2003 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 $176.6 million for 2004 and $305.2 million for 2003. As a result, the Accumulated Income (Deficit) year-end balance is reduced by $481.8 million in 2004 and $305.2 million in 2003.

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 Financial Accounting Standards Board ("FASB") has issued Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" ("FAS 143"). FAS 143 was adopted prospectively on January 1, 2003 and requires liability recognition for retirement obligations associated with tangible long-lived assets. The initial measurement of the asset retirement obligation is to be at fair value. The asset retirement cost equal to the fair value of the retirement obligation is to be capitalized as part of the cost of the related long-lived asset and amortized to expense over the useful life of the asset. The liability accretes until the expected settlement of the retirement obligation.

Canadian standards are consistent with the requirements under FAS 143, except under U.S. GAAP the change was effective January 1, 2003. Under U.S. GAAP, prior periods are not restated for the change in

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accounting policy and the effect of the change is charged to income. The difference between Canadian GAAP and U.S. GAAP of the effect of this change in accounting policy has been accounted for as a cumulative effect adjustment in the 2003 Consolidated Statement of Operations as a loss of $1.7 million, net of income taxes of $1.4 million.

(d) During 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. As the exercise price of the unit rights granted under the plan as 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 exercise 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 does not result in a difference between Canadian and U.S. 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"). Since all options were granted with exercise price equal to the market price at the date of the grant, no compensation cost has been charged to income at the time of the option grants. Had compensation cost for the Company's stock options been determined based on the fair market value at the grant dates of the awards consistent with methodology prescribed by FAS 123, "Accounting for Stock-Based Compensation", the net loss and net loss per unit for the year ended December 31, 2003 would have been the pro forma amounts indicated below:

	Year Ended December 31 2003
Net income (loss) US GAAP as reported	$ (812)
Stock based compensation expense	(5,522)
Pro forma	$ (6,334)
Net income (loss) per unit:	
Basic as reported	$ (0.01)
Pro forma	$ (0.11)
Diluted as reported	$ (0.01)
Pro forma	$ (0.11)

The weighted average fair market value of options granted in 2003 was $4.21 per option The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk free interest rate of four percent; expected life of four years; and expected volatility of 52 percent.

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 are subject to variable plan accounting, which results in an increase of compensation cost of $12.3 million for the year ended December 31, 2003 for U.S. GAAP purposes.

(e) The Company adopted the liability method of accounting for income taxes in 2000 retroactively without restatement. The liability method of accounting for income taxes is similar to Statement of

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Financial Accounting Standards No. 109, which requires the use of the asset and liability method. The Canadian GAAP liability method requires the measurement of future income tax liabilities and assets using income tax rates that reflect enacted income tax rate reductions provided it is more likely than not that the Company will be eligible for such rate reductions in the period of reversal. U.S. GAAP allows recording of such reductions only when claimed.

(f) 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, 2004, the Trust's financial instruments that do not meet the specific hedge accounting under U.S. GAAP would be recorded as a asset on the balance sheet at their fair value of $2.8 million (2003 – liability of $6.2 million).

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 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.

(g) The income tax effect of the items noted in (a) through (f) for the year ended December 31, 2004 is an increase in income taxes of $3.9 million (2003 – decrease of $16.5 million).

(h) 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.

(i) Effective January 1, 2004, The Trust has prospectively adopted FASB Interpretation No. ("FIN") 46(R) "Consolidation of Variable Interest Entities". FIN 46(R) clarifies the application of Accounting Research Bulletin No. 51 "Consolidated Financial Statements" to those entities (defined as VIE's) in which the equity as risk is not sufficient to permit that entity to finance its activities without additional subordinated financial support from other parties. The VIE definition also extends to entities where equity investors lack voting control, an obligation to absorb expected losses or the right to receive expected residual returns. FIN 46(R) requires consolidation by a business of VIE's in which it is the primary beneficiary. The primary beneficiary is defined as the party that has exposure to the majority of the expected losses and/or expected residual returns of the VIE. Adoption of FIN 46(R) had no material impact on the financial results of the Trust.

Consolidated Statements of Operations

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

	Years Ended December 31	
	2004	2003 (note 3)
Net income for the year – Canadian GAAP	$ 13,763	$ 35,844
Adjustments:		
Depletion (a)	527	(34,701)
Non-controlling interest (b)	347	(668)
Compensation expense (d)	—	(11,972)
Interest rate swaps (f)	(1,061)	(12,181)
Financial derivative instruments (f)	10,110	8,109
Income taxes (g)	(3,886)	16,482
Net income from continuing operations before cumulative effect of change in accounting policy for asset retirement obligations	19,800	913
Cumulative effect of change in accounting policy for asset retirement obligations (c)	—	(1,725)
Net income (loss) for the year – U.S. GAAP	$ 19,800	$ (812)
Net income per unit before cumulative effect of change in accounting policy for asset retirement obligations – U.S. GAAP		
Basic	$ 0.30	$ 0.02
Diluted	$ 0.30	$ 0.02
Net income (loss) per unit – U.S. GAAP		
Basic	$ 0.30	$ (0.01)
Diluted	$ 0.30	$ (0.01)

Consolidated Balance Sheets

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

	December 31, 2004		
	Canadian GAAP as Reported	Increase (Decrease)	U.S. GAAP

Assets:			
Capital assets (a)	$ 1,009,933	$ (136,654)	$ 873,279
Financial derivative instruments (e)	—	2,858	2,858
Liabilities:			
Future income taxes (g)	164,909	(61,583)	103,326
Non-controlling interest (b)	12,962	(12,962)	—
Temporary equity (b)	—	878,794	878,794
Unitholders' equity:			
Unitholders' capital (b)	515,728	(515,728)	—
Accumulated income (deficit) – see below	5,694	(585,986)	(580,292)

	December 31, 2003		
	Canadian GAAP as Reported (note 3)	Increase (Decrease)	U.S. GAAP (restated note 20(b))
Assets:			
Capital assets (a)	$ 866,637	$ (150,282)	$ 716,355
Liabilities:			
Financial derivative instruments (e)	—	6,191	6,191
Future income taxes (g)	170,952	(70,437)	100,515
Non-controlling interest (b)	25,705	(25,705)	—
Temporary equity (b)	—	702,154	702,154
Unitholders' equity:			
Unitholders' capital (b)	449,403	(449,403)	—
Accumulated deficit – see below	(8,069)	(415,384)	(423,453)

	December 31,	
	2004	2003 (restated note 20(b))
Accumulated income (deficit) - Canadian GAAP	$ 5,694	$ (8,069)
Adjustments to depletion (a)	(162,337)	(162,864)
Compensation expense (d)	(13,845)	(13,845)
Financial derivative instruments (f)	2,858	(6,191)
Non-controlling interest (b)	(321)	(668)
Change in redemption value of trust units (b)	(481,810)	(305,170)
Adjustments to future income taxes	71,194	75,079
Cumulative effect of change in accounting policy for asset retirement obligation (c)	(1,725)	(1,725)
Accumulated deficit - U.S. GAAP	$ (580,292)	$ (423,453)

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 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. The Trust is evaluating the effect of this standard on its consolidated financial statements.

In June 2004, FASB issued an exposure draft of a proposed Statement, "Fair Value Measurements" to provide guidance on how to measure the fair value of financial and non-financial assets and liabilities when required by other authoritative accounting pronouncements. The proposed statement attempts to address concerns about the ability to develop reliable estimates of fair value and inconsistencies in fair value guidance provided by current U.S. GAAP, by creating a framework that clarifies the fair value objective and its application in GAAP. In addition, the proposal expands disclosures required about the use of fair value to remeasure assets and liabilities. The standard would be effective for financial statements issued for fiscal years beginning after June 15, 2005. The Trust is evaluating the effect of this standard 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

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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.

Other Proposed Standards The CICA has proposed amendments to Section 3500 "Earnings per Share", which include the requirement to include in the computation of basic earnings per share any shares issued upon conversion of a mandatorily convertible instrument. The computational guidance for calculating the number of incremental shares included in diluted shares when applying the treasury stock method is also amended. These amendments were not enacted in final form as of the time of release of the Trust's 2004 consolidated financial statements.

The CICA has issued an Exposure Draft of a new Section 3830, "Non-Monetary Transactions" which proposes that all non-monetary transactions be measured at fair value, unless certain criteria are met. A final standard is planned to be issued in the first quarter of 2005.

A Re-Exposure draft on Section 3820, "Subsequent Events" was issued in January 2005, which proposes to separately define the subsequent event period and to require disclosure of the dates to which subsequent events are reflected in the financial statements. This Re-Exposure draft was not enacted in final form as of the time of release of the Trust's 2004 consolidated financial statements.

Regarding this MD&A The following discussion and analysis, dated March 7, 2005, 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, 2004 and 2003. 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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 payout ratio 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, 2004 and 2003, 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.

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

2004 OVERVIEW

ACQUISITIONS

Effective September 22, 2004, the Company acquired all of the outstanding shares of a Calgary based private oil and gas company for a cash consideration of $109 million. The results of its operations have been included in the consolidated financial statements of the Trust since the effective date. This acquisition added approximately 3,000 boe per day of production comprised of 12 mmcf/d of natural gas and 1,000 barrels per day of light oil and NGLs from three geographically-focused areas in southern Alberta. Subsequent to the acquisition, the private company was amalgamated with the Company.

Effective December 22, 2004, the Company acquired oil and natural gas interests in the West Stoddart area of northeast British Columbia for a total cash consideration of $90 million. This property added approximately 3,300 boe per day of primarily high netback liquids-rich natural gas production comprised of 10.0 mmcf/d of natural gas, 1,300 barrels per day of NGLs and 330 barrels per day of light oil. The production is from three properties near Fort St. John, B.C. generally with year-round access for efficient operations and capital activities.

OPERATIONS REVIEW

PRINCIPAL PROPERTIES

Baytex's crude oil and natural gas operations are organized into two operating districts – the Heavy Oil District and the Conventional Oil and Gas District. Each district constitutes an extensive portfolio of operated properties and development prospects with considerable upside potential. Baytex has established skilled technical teams to operate 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 of exploration, development and acquisition opportunities and improves cost efficiency.

HEAVY OIL DISTRICT

The Heavy Oil District accounts for approximately 60 percent of the Trust's current production and approximately three-quarters of its reserves and 50 percent of cash flow from operations. Heavy oil operations consist largely of cold conventional production from wells with multi-zone potential. Production is generated primarily from vertical, slant and horizontal wells using progressive cavity pump technology to generate large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 100 barrels per day of low gravity crude ranging from 11 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. After being sold by Baytex, the crude oil is then upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt.

In 2004, production in the Heavy Oil District averaged 22,700 barrels per day of heavy oil and 8.9 mmcf/d of natural gas (24,200 boe per day). Baytex drilled 115 gross (113.7 net) wells in the heavy oil district resulting in 95 gross (95.0 net) oil wells, three gross (2.2 net) gas wells, seven gross (6.5 net) stratigraphic test wells, and 10 gross (10.0 net) dry and abandoned wells, for a success rate of 91.3 percent.

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 deposits. The ability to generate relatively lowcost replacement production through conventional cold production methods is one of the key elements of the Trust's sustainability.

The Trust will continue to build value through internal property development and selective acquisitions. Future heavy oil activity will focus on the development of the Seal and Ardmore properties along with continued infill drilling at the adjacent Cold Lake property and throughout the Saskatchewan properties. Company net undeveloped lands in this district totaled 344,892 acres at year-end 2004.

ARDMORE – ALBERTA

Ardmore is one of the key heavy oil development and production areas for the Trust. Acquired in 2002 with production of 2,200 barrels per day, Ardmore has been developed in the Sparky, McLaren and Colony formations. Average production during 2004 was 4,200 barrels per day of oil and 1.0 mmcf/d of natural gas (4,400 boe per day). Current production is 3,800 barrels per day of oil and 950 mcf/d of natural gas (4,000 boe per day). Baytex has applied leading-edge slotted-liner production technology to improve production and increase wellbore stability. Slotted-liner wells in the area are capable of producing up to 300 barrels per day of heavy oil and continue to be used extensively for pool development projects. Twenty-six oil wells and three dry wells were drilled in the area during 2004 and 20 to 25 wells are anticipated to be drilled during 2005. During 2004, operating expenses were reduced to $5.50/bbl primarily by building a water disposal facility and conserving solution gas produced in conjunction with the heavy oil. It is expected that operating expenses will be further reduced as a result of the construction of a sand disposal facility in late 2004. The Trust also added 6,500 acres of new lands through Crown land sales in 2004 that are prospective for Colony oil pool development. Company net undeveloped lands were 39,120 acres at year-end 2004.

COLD LAKE – ALBERTA

Baytex acquired the Cold Lake heavy oil property in 2001. This year-round drilling area is located on the Cold Lake First Nations lands, with heavy oil production generated largely from the Colony formation. Average production was 1,000 barrels per day during 2004. The Trust drilled 12 oil wells and three dry wells in the Cold Lake area during 2004. Up to 15 new drills are anticipated during 2005. Company net undeveloped lands were 18,062 acres at year-end 2004.

SEAL – ALBERTA

The Seal property is a highly prospective property located in the Peace River oil sands area of northwest Alberta. The Trust holds a 100 percent working interest in approximately 96 sections of land, of which 42 sections were acquired in 2004. The Seal oil deposits can be produced through horizontal well-bores at initial rates of approximately 200 barrels per day per well without the use of capital intensive steam injection methods. A seven-well stratigraphic test program completed during the first quarter of 2004 has led to the Trust's current development program on the western block of these land holdings. Two horizontal wells drilled at the end of 2004 are currently producing a total of approximately 400 barrels per day. The prospective undeveloped area of the western block is over 25,000 acres. During 2005, Baytex plans to drill up to six additional stratigraphic test wells to further delineate this land block and up to 15 horizontal producers in the immediate area that are currently producing. In addition, other industry operators are currently drilling horizontal production wells on adjoining sections that will help define the productive capability of the Trust's lands. Company net undeveloped lands in this area were 63,680 acres at year-end 2004.

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. Provincial government regulations generally prohibit production from more than one formation at a time. As such, this property possesses long-term development potential from a considerable number of up-hole recompletion opportunities. Average production during 2004 was approximately 3,800 barrels per day of heavy oil and 1.2 mmcf/d of natural gas (4,000 boe per day). Ongoing projects in the area include up to 15 development wells during 2005, uphole recompletions after depletion of deeper producing intervals, and optimization of the solution gas gathering system. Company net undeveloped lands were 11,160 acres at year-end 2004.

CARRUTHERS – SASKATCHEWAN

The Carruthers property was obtained by Baytex in 1997. The property consists of separate "North" and "South" oil pools in the Cummings

formation. Typical vertical oil wells initially produce approximately 40 barrels per day with ultimate recoveries of approximately 60,000 barrels of reserves. During 2004, average production was approximately 3,200 barrels per day of heavy oil and 850 mcf/d of natural gas (3,300 boe per day). The Trust drilled 1.2 net natural gas wells and 14 net oil wells in South Carruthers and three net horizontal oil wells in North Carruthers during 2004. This area represents a relatively stable production base with continued development drilling expected to total 10 to 15 wells annually. Company net undeveloped lands were 14,425 acres at year-end 2004.

MARSDEN/EPPING/MACKLIN/SILVERDALE – SASKATCHEWAN

This area of Saskatchewan is characterized by low-access costs and higher quality oil of 13 to 18 API gravity and low sand content. Initial production rates are typically 70 barrels per day and primary recovery factors can be as high as 30 percent of the original oil in place. This oil is also receptive to waterflood recovery schemes to further increase recovery. Average production in this area during 2004 was approximately 4,600 barrels per day. Twenty oil wells were drilled in 2004, increasing production to over 4,900 barrels per day by year-end. In addition, ongoing flow-line installation and water disposal projects have combined to keep operating costs below $5.50/bbl. Drilling in 2005 will add up to 15 new oil wells, mostly through development of the Macklin pool. In Epping, waterflood and solution gas tie-in projects are planned for 2005. Company net undeveloped lands were 20,932 acres at year-end 2004.

CONVENTIONAL OIL AND GAS DISTRICT

The Conventional Oil and Gas district produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. In 2004, production averaged 46.0 mmcf/d of natural gas and 2,200 barrels per day of hydrocarbon liquids (9,800 boe per day). In 2004, the Conventional District drilled 23 gross (20.9 net) wells resulting in four gross (4 net) oil wells, 14 gross (12.4 net) gas wells and five gross (4.5 net) dry and abandoned wells for a success rate of 78 percent. The Company undeveloped lands in the Conventional district were 453,055 net acres at year-end 2004. During 2004, property acquisitions at Garden Plains, Turin and Stoddart were added to the Conventional District.

STODDART – BRITISH COLUMBIA

The Stoddard asset acquisition was closed on December 22, 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnal, Coplin and Bluesky formations. Oil is treated at two Company-operated batteries. Natural gas is compressed at four company-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Year-end 2004 production was approximately 10 mmcf/d of natural gas and 1,700 barrels per day of hydrocarbon liquids (3,400 boe per day). The Company plans to drill approximately four wells and recomplete up to seven wells in 2005 in the Stoddart area. Company net undeveloped lands were 25,343 acres at December 31, 2004.

GARDEN PLAINS/SEDALIA – ALBERTA

In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. December 2004 gas production was approximately 10 mmcf/d (1,700 boe per day). This area has the advantage 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. The Company plans to drill four wells during 2005 in this area. Company net undeveloped lands were 77,498 acres at year-end 2004.

TURIN – ALBERTA

This multi-zone, year-round access property was acquired in 2004. December 2004 production was approximately two mmcf/d of natural gas and 900 barrels per day liquids (1,200 boe per day). 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. The Company plans to drill approximately five wells and recomplete up to 10 other wells during 2005 in the Turin area. Company net undeveloped lands were 31,335 acres at December 31, 2004.

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 2004 from this area averaged approximately eight mmcf/d of natural gas and 1,000 barrels per day hydrocarbon liquids (2,300 boe per day). In 2004, Baytex drilled eight net wells in 2004 resulting in four oil wells, two gas wells and two abandoned wells and plans to drill one well during 2005. Company net undeveloped lands were 44,448 acres at year-end 2004.

BON ACCORD – ALBERTA

This multi-zone property was acquired by Baytex in 1997. Production is from the Belly River, Viking and Mannville formations and averaged approximately six mmcf/d of gas and 300 barrels per day of hydrocarbon liquids (1,300 boe per day) in 2004. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. In late 2004, Baytex drilled two gas wells (1.5 net) which will be put on production in 2005, and plans to drill one well during 2005. Company net undeveloped lands were 47,725 acres at year-end 2004.

LEAHURST – ALBERTA

Production averaged approximately eight mmcf/d (1,300 boe per day) in 2004 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 2004, Baytex drilled five Mannville natural gas wells resulting in three gas wells and two abandonments. Baytex also successfully recompleted nine wells for coal-bed methane production from the Horseshoe Canyon coals during 2004. In 2005, Baytex plans to drill approximately 15 wells and recomplete seven wells in the Leahurst area. Company net undeveloped lands were 35,310 acres at year-end 2004.

NINA/DARWIN – 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 2004 averaged approximately five mmcf/d (800 boe per day). Six net wells were drilled in 2004 resulting in three producing gas wells. Company net undeveloped lands were 46,203 acres at year-end 2004.

HEAVY OIL SUPPLY AGREEMENT

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 barrels per day of Lloyd Blend ("LLB") quality crude at Hardisty, Alberta through the Express Pipeline to Guernsey, Wyoming. The blended crude is comprised of approximately 15,500 barrels of Baytex production and 4,500 barrels per day 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 production.

The Frontier Crude Oil Supply Agreement effectively mitigates the risk of volatile heavy oil differentials on Baytex's cash flow

MARKETING

CRUDE OIL

World crude oil prices reached unprecedented levels in 2004 as strong Asian demand, uncertainty over Middle East supplies, hurricane-inflicted damage to U.S. Gulf of Mexico production facilities and diminishing excess OPEC productive capacity all contributed to record prices. Benchmark West Texas Intermediate (WTI) prices, after reaching an all-time high of US$55.17 per barrel in late October, averaged $41.40 in 2004, an increase of 33 percent from the 2003 average of $31.04. The five-year average is $30.92.

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 $52.57 per barrel in 2004, up 22 percent from $43.16 in 2003. The five-year average is $43.82.

Baytex's conventional crude oil and natural gas liquids prices averaged $48.64 per barrel in 2004 compared to $40.01 in 2003.

With OPEC increasing oil output late in 2004 to meet surging world demand, supplies of heavy and sour crude oil grades increased and prices versus benchmark light sweet prices deteriorated. Canadian heavy oil prices were affected by this increased supply as the differential between WTI and Lloyd blend prices in Alberta averaged US$14.01 per barrel in 2004 (34 percent of WTI) compared to US$8.88 in 2003 (29 percent of WTI), with five-years averages at US$9.68 and 31 percent.

Baytex's heavy oil prices averaged $30.32 per barrel in 2004, compared to $26.68 in 2003.

Baytex's heavy crude oil is shipped to the Frontier Refinery in Cheyenne, Wyoming via the Express Pipeline system.

NATURAL GAS

Natural gas prices in North America were strong in 2004, reflecting high oil prices and concerns over gas supplies. U.S. gas prices, represented by the NYMEX futures contract, averaged US$6.09 per thousand cubic feet (mcf) in 2004, an increase of 12 percent from $5.44 in 2003. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $6.53/mcf in 2004 compared to $6.66 in 2003, due to the impact of the strong Canadian dollar. Five-year average prices are US$4.62 for the NYMEX contract, and $5.71 for Alberta daily prices.

Baytex received an average of $6.46 per mcf for 2004 natural gas sales compared to $6.23 in 2003.

PRODUCTION

The Trust's average production for fiscal 2004 decreased by seven percent to 34,022 boe per day from 36,686 boe per day for fiscal 2003 due to asset dispositions and the transfer of properties pursuant to the Plan of Arrangement.

Light oil production decreased four percent to 2,172 barrels per day during 2004 from 2,273 barrels per day in 2003. Heavy oil production during 2004 was 22,703 barrels per day, a decrease of five percent from production of 23,911 barrels per day during 2003. Natural gas production for 2004 decreased by 13 percent to 54.9 mmcf/d compared to 63.0 mmcf/d for the prior year.

PRODUCTION BY AREA

	Light Oil	**Barrels of**

	and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Oil Equivalent (boe/d)
2004				
Heavy Oil District	**—**	**22,703**	**8.9**	**24,177**
Conventional Oil and Gas District	**2,172**	**—**	**46.0**	**9,845**
Total Production	**2,172**	**22,703**	**54.9**	**34,022**
2003				
Heavy Oil District	—	23,911	10.6	25,676
Conventional Oil and Gas District	2,273	—	52.4	11,010
Total Production	2,273	23,911	63.0	36,686

REVENUE

Petroleum and natural gas sales for 2004 increased by four percent to $420.4 million from $403.0 million for fiscal 2003. Benchmark WTI crude oil averaged US$41.40 per barrel for 2004, representing a 33 percent increase over the US$31.04 per barrel for 2003. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$0.7683 in 2004, compared to US$0.7135 in 2003. The Trust's light oil and NGLs price increased to $48.64 per barrel from $40.01 per barrel. The heavy oil price increased 14 percent to $30.32 per barrel in 2004 from $26.68 per barrel in 2003. Natural gas prices were four percent higher in 2004, averaging $6.46 per mcf compared to $6.23 per mcf during the previous year. Overall, after accounting for $78.1 million of realized losses on financial derivative contracts, the Trust averaged $27.48 per boe for 2004, a two percent decrease from $28.07 per boe received in the prior year. For the per-sales-unit calculations, heavy oil sales for 2004 were five barrels per day lower (2003 – 650 barrels per day lower) than the production for the year due to inventory in transit under the Frontier supply agreement.

For 2004, light oil revenue increased 16 percent over 2003, due to a 22 percent increase in wellhead prices and a four percent decrease in production. Revenue from heavy oil increased 11 percent due to a five percent decrease in sales volume and a 14 percent increase in wellhead prices. Natural gas revenue decreased 10 percent as the 13 percent production decrease was offset by a four percent increase in wellhead price.

GROSS REVENUE ANALYSIS

	2004		2003	
	$thousands	$/Unit(1)	$thousands	$/Unit (1)
Oil revenue (barrels)				
Light oil	**38,673**	**48.64**	33,197	40.01
Heavy oil	**252,016**	**30.32**	226,482	26.68
Derivative contract loss	**(78,124)**	**(8.58)**	(33,777)	(3.62)
Total oil revenue	**212,565**	**23.34**	225,902	24.24
Natural gas revenue (mcf)	**129,711**	**6.46**	143,343	6.23
Total revenue (boe @ 6:1)	**342,276**	**27.48**	369,245	28.07

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

ROYALTIES

For the year ended December 31, 2004, royalties decreased to $66.0 million from $67.2 million for last year and were 15.7 percent of sales compared to 16.7 percent of sales in 2003. Royalties for 2004 were 14.1 percent of sales for light oil, 13.3 percent for heavy oil and 20.9 percent for natural gas. These rates compared to 17.4 percent, 13.0 percent and 22.3 percent, respectively, for 2003.

OPERATING EXPENSES

Operating expenses for 2004 increased five percent to $89.1 million from $86.0 million for 2003. This increase is attributable to general industry inflation. Operating expenses were $7.15 per boe for 2004 compared to $6.54 per boe for the prior year. In 2004, operating expenses were $9.51 per barrel of light oil, $7.83 per barrel of heavy oil and $0.82 per mcf of natural gas compared to $8.32, $7.34 and $0.73, respectively, for 2003.

TRANSPORTATION EXPENSES

Transportation expenses for 2004 were $18.7 million compared to $17.8 million for 2003. These expenses were $1.50 per boe in 2004 compared to $1.36 in 2003. Transportation expenses were $1.66 per barrel of oil and $0.18 per mcf of natural gas in 2004 and $1.50 per barrel of oil and $0.16 per mcf of natural gas in 2003.

OPERATING NETBACKS

	Light oil and NGLs ($/bbl)		Heavy Oil ($/bbl)		Total Oil and NGLs ($/bbl)		Natural Gas ($/mcf)		BOE ($/boe)	
	2004	2003	2004	2003	2004	2003	2004	2003	2004	2003
Sales price	**48.64**	40.01	**30.32**	26.68	**31.91**	27.86	**6.46**	6.23	**33.75**	30.64
Royalties	**(6.88)**	(6.96)	**(4.02)**	(3.47)	**(4.27)**	(3.78)	**(1.35)**	(1.39)	**(5.30)**	(5.11)

Operating costs	**(9.51)**	(8.32)	**(7.83)**	(7.34)	**(7.97)**	(7.43)	**(0.82)**	(0.73)	**(7.15)**	(6.54)
Transportation	**(0.92)**	(0.97)	**(1.73)**	(1.55)	**(1.66)**	(1.50)	**(0.18)**	(0.16)	**(1.50)**	(1.36)
Net revenue	**31.33**	23.76	**16.74**	14.32	**18.01**	15.15	**4.11**	3.95	**19.80**	17.63

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 $15.2 million compared to $8.9 million for the prior year. On a per sales unit basis, these expenses were $1.22 per boe in 2004 and $0.71 per boe in 2003. In accordance with full cost accounting policy, $4.4 million of expenses were capitalized in 2003, while no expenses have been capitalized in 2004. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

GENERAL AND ADMINISTRATIVE EXPENSES

($ thousands)	**2004**	**2003**
Gross corporate expense	**20,413**	20,496
Operator's recoveries	**(5,170)**	(7,166)
Subtotal	**15,243**	13,330
Capitalized expense	**—**	(4,403)
Net expense	**15,243**	8,927

UNIT BASED COMPENSATION EXPENSE

The Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. The Trust is unable to determine the fair value of the rights granted as the plan contains a provision for the reduction, in certain circumstances, in the exercise price. Therefore, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. For 2004, compensation expense was $7.7 million compared to $0.7 million for 2003. Compensation expense on the Trust's unit rights incentive plan has been determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements. The compensation expense for 2003 also includes $0.5 million based on the fair value of the stock options outstanding prior to the Plan of Arrangement

INTEREST EXPENSE

In 2004, interest expense was $19.4 million for the year compared to $23.5 million last year. The decrease in total interest expense is due to the redemption of the Company's senior secured notes in May 2003 and the stronger Canadian currency as interest on the long-term notes is denominated in U.S. dollars.

COSTS ON REDEMPTION AND EXCHANGE OF NOTES

On July 9, 2003, the Company completed an exchange offer related to its previously outstanding US$150 million 10.5 percent senior subordinated notes due 2011 (the "Old Notes"). The Company issued US$179.7 million of 9.625 percent senior subordinated notes due 2010 in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. Also recognized in income is $4.7 million of costs on the redemption of the US$57 million 7.23 percent senior secured notes.

FOREIGN EXCHANGE

The foreign exchange gain for 2004 was $16.0 million compared to a gain of $52.1 million in the prior year. The 2004 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.8308 at December 31, 2004 compared to 0.7737 at December 31, 2003. The 2003 gain is based on translation at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002.

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion increased to $160.8 million for 2004 compared to $123.1 million for the same period last year. On a sales-unit basis, the depletion and depreciation provision for the current period was $12.91 per boe compared to $9.36 per boe for the same period a year earlier. This rate increase is due to the revisions in proved reserves at year-end 2003 pursuant to the implementation of the new standards of disclosure for oil and gas activities, National Instrument ("NI") 51-101.

INCOME TAXES

Current tax expenses were $9.0 million for 2004 compared to $9.7 million for the same period last year. The current tax expense is comprised of $7.0 million of Saskatchewan Capital Tax and $2.0 million of Large Corporation Tax compared to $8.0 million and $1.7 million, respectively, in 2003.

The fiscal 2004 provision for future income taxes was a recovery of $41.2 million compared to a recovery of $14.5 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)	December 31, 2004
Cumulative Canadian Exploration Expense	1,283
Cumulative Canadian Development Expense	99,741
Cumulative Canadian Oil and Gas Property Expense	155,930
Undepreciated Capital Cost	195,235
Other	39,430
	491,619

CASH FLOW FROM OPERATIONS

Cash flow from operations 2004 decreased 1.6 percent to $136.0 million from $138.2 million for the previous year. On a barrel of oil equivalent basis, cash flow from operations was $10.03 for 2004 compared to $10.40 for 2003. The decrease is due to higher realized losses from financial derivative contracts in 2004.

CASH FLOW NETBACKS

	2004		2003	
	$/boe	Percent	$/boe	Percent
Production revenue	**33.75**	**100**	30.64	100
Derivative contract loss	**(6.27)**	**(19)**	(2.57)	(8)
Royalties	**(5.30)**	**(16)**	(5.11)	(17)
Operating expenses	**(7.15)**	**(21)**	(6.54)	(21)
Transportation	**(1.50)**	**(4)**	(1.36)	(5)
Field netbacks	**13.53**	**40**	15.06	49
General and administrative expenses	**(1.22)**	**(4)**	(0.71)	(2)
Reorganization costs	**—**	**—**	(1.43)	(5)
Interest expense	**(1.56)**	**(4)**	(1.79)	(6)
Current income taxes	**(0.72)**	**(2)**	(0.73)	(2)
Cash flow netbacks	**10.03**	**30**	10.40	34

NET INCOME

Net income for 2004 was $13.8 million compared to $35.8 million for 2003. The increased petroleum and natural gas sales realized through higher wellhead prices in 2004 were offset by increased charges for depletion, depreciation and accretion, a lower foreign exchange gain and a higher realized loss on financial derivatives. 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.

CAPITAL EXPENDITURES

Exploration and development expenditures decreased to $94.5 million for 2004 compared to $179.2 million last year. The lower capital expenditures reflect a different business plan since the conversion to an income trust. For the year ended December 31, 2004, the Trust participated in the drilling of 138 (135.0 net) wells, resulting in 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 compared to prior year activities of 266 (243.4 net) wells, including 173 (158.9 net) oil wells, 67 (61.4 net) gas wells, seven (5.1 net) service wells and 19 (18.0 net) dry holes. On September 22, 2004, the Company acquired all of the issued and outstanding shares of a private oil and gas company with operations in Alberta for $109 million plus adjustments. Effective December 22, 2004, the Company acquired oil and natural gas interests in the West Stoddart area of northeast British Columbia for $90 million plus adjustments.

Year Ended December 31 **($ thousands)**	2004	2003
Land	**8,744**	14,138
Seismic	**1,283**	5,436
Drilling and completion	**55,322**	110,892
Equipment	**25,982**	42,365
Other	**3,152**	6,401
Total exploration and development	**94,483**	179,232
Corporate acquisition	**111,042**	—
Property acquisitions	**89,582**	6,644
Property dispositions	**(14,441)**	(137,493)
Total capital expenditures	**280,666**	48,383

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2004, total net debt (including working capital) was $422.0 million compared to $213.6 million at December 31, 2003. The $422.0 million net debt included $9.5 million of notional liabilities based on the mark-to-market valuations of derivative contracts as at December

31, 2004. The increase in total debt at year-end 2004 compared to 2003 was the result of the increase in bank loans used to fund capital expenditures during 2004.

The Company's debt structure consists of two components. The first component is the senior 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 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, 2004 at total of $161.4 million had been drawn under the credit facilities.

The second component is the senior subordinated notes. On February 12, 2001, the Company issued US$150 million of senior subordinated term notes ("Old 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. On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million ($247.1 million) of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

The bank credit facilities contain restrictions on the Company's ability to make distributions to the Trust if the Company is in default under such facilities or the distribution would have a material adverse effect on the ability of the Company to meet its obligations to its lenders. In addition, the note indenture relating to the senior subordinated notes contains a limitation on restricted payments whereby the Company is restricted from making any restricted payments, including distributions to the Trust, if a default or event of default under the note indenture has occurred and is continuing.

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. Pursuant to the Plan of Arrangement, 53.3 million trust units and 4.7 million exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company. An additional 6.5 million trust units were issued on December 12, 2003 for gross proceeds of $65 million. On December 20, 2004, the Trust issued 3.6 million trust units at $12.80 per unit for gross proceeds of $46.1 million.

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders can elect to reinvest monthly cash distributions in additional trust units of the Trust. Trust units purchased from treasury under the DRIP will be issued at a 5 percent discount from the weighted average closing price of the trust units on the Toronto Stock Exchange 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.

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, 2004, there were 1.9 million exchangeable shares outstanding. During 2004, a total of 1.8 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, 2004 was 1.21472 trust units per exchangeable share (December 31, 2003 – 1.04530 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 2004 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.

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

		Payments Due by Period			
($ thousands)	**Total**	**Less than 1 year**	**1-3 years**	**4-5 years**	**After 5 years**
Long-term debt (1)	216,583	—	—	—	216,583
Operating leases	9,473	1,359	5,469	2,645	—
Capital lease	782	221	561	—	—
Transportation agreements	5,166	2,675	2,491	—	—
Total contractual obligations	232,004	4,255	8,521	2,645	216,583

(1) Total US $180 million

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 independent members of the Company's Board of Directors, assists the Board in their annual review of the reserves evaluation.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on reserves 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 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 U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. 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 16 of the consolidated financial statements.

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 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. 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 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.

CHANGES IN ACCOUNTING POLICIES

UNIT-BASED COMPENSATION

At December 31, 2003, the Trust elected to adopt amendments to CICA Handbook Section 3870, “Stock-based Compensation and Other Stock-based Payments” pursuant to the transitional provisions contained therein. Under this amended standard, the Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. For the year ended December 31, 2003, compensation expense of $0.22 million was recorded as non cash general and administrative expense for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. For the year ended December 31, 2003, compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (note 18 to the consolidated financial statements).

FULL COST ACCOUNTING

In 2003, the CICA issued Accounting Guideline 16, Oil and Gas Accounting – Full Cost (AcG-16). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline modifies the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition 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 carrying amount 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. The adoption of this guideline on January 1, 2004 did not have an impact on the financial results of the Trust. The ceiling test impairment test was calculated on January 1, 2004 using the following benchmark reference prices at January 1, 2004 for the years 2004 to 2008 adjusted for commodity differentials specific to the Trust (note 17 to the consolidated financial statements):

2004	2005	2006	2007	2008

WTI ($US/bbl)	29.63	26.80	25.76	26.14	26.53
AECO ($CDN/mcf)	6.03	5.36	4.80	4.91	4.98

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, the Trust adopted the CICA Section 3110, “Asset Retirement Obligations”. This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation 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 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 incurred.

The provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of this change, net income for the comparative year ended December 31, 2003 decreased by $2.8 million, net of future income tax of $0.8 million. At December 31, 2003 the asset retirement obligations balance increased by $32.5 million to $56.0 million, the petroleum and natural gas assets balance increased by $19.2 million to $862.3 million and the future tax liability decreased by $5.0 million to $169.3 million. The opening 2003 accumulated deficit increased by $5.4 million (net of future income tax of $0.8 million). There was no impact on cash flow from operations as a result of adopting this policy (note 8 to the consolidated financial statements).

FINANCIAL DERIVATIVE CONTRACTS

Effective January 1, 2004, the Trust implemented CICA Accounting Guideline 13 “Hedging Relationships” (AcG-13) for accounting for derivative contracts. This guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, 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 derivatives. Upon implementation of AcG-13, Emerging Issues Committee Abstract 128 (EIC-128) also became effective. EIC-128 requires that changes in the fair value of these derivative contracts that do not qualify for hedge accounting under AcG-13 be recognized in the balance sheet and measured at fair value, with changes in fair value reported as income or expense in each reporting period. The income or expense relating to the change in fair value of the derivative contracts is an expense that has no impact on cash flow but may result in significant fluctuations in net income due to volatility in the underlying market prices. In accordance with the transitional provisions of AcG-13 and EIC-128, the new accounting treatment has been applied prospectively whereby prior periods have not been restated.

Prior to January 1, 2004, the Trust accounted for all derivative contracts whereby realized gains and losses on such contracts were included in the statement of operations within the corresponding item to which the contract was related. Following implementation of the guideline, realized and unrealized gains and losses on derivative contracts that do not qualify as effective hedges are reported separately in the statement of operations.

Pursuant to the transitional provisions contained in AcG-13, on January 1, 2004, the Trust recorded a deferred charge for the unrealized loss of $10.1 million for the mark-to-market value of the outstanding non-hedging financial derivatives. This balance has being recognized in income during the year ended December 31, 2004. At December 31, 2004, the Trust recorded 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 from the inception of the contracts to December 31, 2004 has been recorded as an unrealized gain on non-hedging financial derivatives of $0.6 million in the consolidated statement of operations (note 16 to the consolidated financial statements).

TRANSPORTATION COSTS

CICA Handbook Section 1100, “Generally Accepted Accounting Principles”, is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior periods, it had been industry practice to record revenue net of related transportation costs. In accordance with the new accounting standards, revenue is now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs for the year ended December 31, 2004 both increased by $18.7 million (2003 – $17.8 million) as a result of this change. This change in classification has no impact on net income and the comparative figures have been restated to conform to the presentation adopted for the current period.

NON-CONTROLLING INTEREST

The Trust has implemented the accounting for the exchangeable shares issued by the Company as required by EIC Abstract 151, “Exchangeable Securities Issued by Subsidiaries of Income Trusts” (EIC 151), issued in January 2005. Under EIC 151, exchangeable shares issued by a subsidiary of an income trust are presented as non-controlling interest, unless certain conditions are met. 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. The presentation of the exchangeable shares at December 31, 2003 was restated to conform to the presentation for the current year, pursuant to the transitional provisions contained in EIC 151. Previously, the exchangeable shares were reflected as a component of Unitholders’ Equity (note 10).

As a result of the adoption of EIC 151, net income was reduced in 2004 by $0.35 million for the non-controlling interest’s share of income and was increased in 2003 by $0.67 million for the non-controlling interest’s share of the loss from the date of the Arrangement. There was no impact on cash flow from operations as a result of adopting this policy. As the exchangeable shares are converted to Trust units, 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.

The adoption of EIC 151 had the following impact on the Trust's previously reported financial statements:

($ thousands, except per unit amounts)	Three Months Ended September 2004	June 2004	March 2004	December 2003	September 2003
Net income (loss)					
Previously reported: (1)	(12,604)	(11,170)	(4,296)	9,127	(46,245)
Restated:	(12,554)	(11,213)	(4,578)	8,490	(45,079)
Net income (loss) per unit basic					
Previously reported: (1)	(0.20)	(0.17)	(0.07)	0.14	(0.84)
Restated:	(0.20)	(0.18)	(0.07)	0.14	(0.82)
Net income (loss) per unit diluted					
Previously reported: (1)	(0.20)	(0.17)	(0.07)	0.14	(0.84)
Restated:	(0.20)	(0.18)	(0.07)	0.15	(0.84)

($ thousands, except per unit amounts)	Nine Months Ended September 2004	Six Months Ended June 2004	Year Ended December 2003	Nine Months Ended September 2003
Net income (loss)				
Previously reported: (1)	(28,070)	(15,466)	35,315	26,188
Restated:	(28,345)	(15,791)	35,844	27,354
Net income (loss) per unit basic				
Previously reported: (1)	(0.45)	(0.24)	0.64	0.48
Restated:	(0.45)	(0.25)	0.66	0.51
Net income (loss) per unit diluted				
Previously reported: (1)	(0.45)	(0.24)	0.62	0.48
Restated:	(0.45)	(0.25)	0.62	0.48

($ thousands, except per unit amounts)	As At September 30, 2004	June 30, 2004	March 31, 2004	December 31, 2003	September 30, 2003
Unitholders' Equity					
Previously reported: (1)	325,292	362,791	400,492	431,210	385,678
Restated:	323,083	360,267	397,012	408,176	356,049
Non-controlling interest					
Previously reported:	—	—	—	—	—
Restated:	11,822	12,332	13,198	25,705	30,322

(1) The amounts previously reported as at and for the periods ended September 2003 and December 2003 have been restated for the adoption of the new accounting standard for asset retirement obligations.

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.

OTHER PROPOSED STANDARDS

The CICA has proposed amendments to Section 3500 "Earnings per Share", which include the requirement to include in the computation of basic earnings per share any shares issued upon conversion of a mandatorily convertible instrument. The computational guidance for calculating the number of incremental shares included in diluted shares when applying the treasury stock method

is also amended. These amendments were not enacted in final form as of the time of release of the Trust's 2004 consolidated financial statements.

The CICA has issued an Exposure Draft of a new Section 3830, "Non-Monetary Transactions" which proposes that all non-monetary transactions be measured at fair value, unless certain criteria are met. A final standard is planned to be issued in the first quarter of 2005.

A Re-Exposure draft on Section 3820, "Subsequent Events" was issued in January 2005, which proposes to separately define the subsequent event period and to require disclosure of the dates to which subsequent events are reflected in the financial statements. This Re-Exposure draft was not enacted in final form as of the time of release of the Trust's 2004 consolidated financial statements.

FOURTH QUARTER 2004

The following discussion reviews the Trust's results of operations for the fourth quarter of 2004.

Light oil production for the fourth quarter of 2004 increased by 41 percent to 2,786 barrels per day from 1,982 barrels per day a year earlier primarily due to the acquisition in September 2004. Heavy oil production decreased 8 percent to 22,490 barrels per day for the fourth quarter of 2004 compared to 24,400 barrels per day a year ago. Natural gas production decreased by 6 percent to 55.5 mmcf/d for the fourth quarter of 2004 compared to 58.9 mmcf/d for the same period last year. These decreases are due to a lower exploration and development program in 2004.

Petroleum and natural gas sales increased 24 percent to $111.5 million for the quarter ended December 31, 2004 from $89.5 million for the same period in 2003. Total royalties increased to $17.4 million for the fourth quarter of 2004 from $13.5 million in 2003. Total royalties for the fourth quarter of 2004 were 15.6 percent of sales compared to 15.1 percent of sales for the same period in 2003. Operating expenses for the fourth quarter of 2004 increased to $24.2 million from $22.1 million in the corresponding quarter last year. Operating expenses were $7.63 per boe for the fourth quarter of 2004 compared to $6.74 per boe for the fourth quarter of 2003. Transportation expenses for the fourth quarter of 2004 were $4.6 million compared to $4.7 million for the fourth quarter of 2003. These expenses were $1.43 per boe for the fourth quarter of 2004 compared to $1.45 for the same period in 2003.

General and administrative expenses increased to $4.1 million in the fourth quarter of 2004 from $3.6 million one year ago. On a per sales unit basis, these expenses were $1.43 per boe for the fourth quarter of 2004 compared to $1.21 per boe for 2003. In accordance with full cost accounting policy, no expenses were capitalized in either the fourth quarter of 2003 or 2004.

Interest expense increased to $6.4 million for the fourth quarter of 2004 from $5.2 million for the same quarter last year. The increase can be attributed to interest incurred on amounts drawn on the Trust's credit facilities in the fourth quarter of 2004.

The foreign exchange gain in the fourth quarter of 2004 was $10.9 million compared to a gain of $10.4 million in the prior year.

The provision for depletion, depreciation and accretion was $41.5 million for the fourth quarter of 2004 compared to $42.6 million for the same quarter a year ago. On a sales-unit basis, the provision for the current quarter was $12.87 per boe compared to $12.14 per boe for the same quarter in 2003.

Net income for the fourth quarter of 2004 was $42.1 million compared to $9.0 million for the corresponding quarter of 2003. In 2004, the increased petroleum and natural gas sales realized through higher wellhead prices in 2004 were offset by increased charges for depletion, depreciation and accretion, a lower foreign exchange gain and a higher realized loss on financial derivatives. In 2003, increased depletion expense was offset by foreign exchange gains and a recovery of future income taxes.

OUTSTANDING UNIT INFORMATION

At of February 28, 2005, the Trust had 66,650,987 units outstanding and the Company had 1,860,944 exchangeable shares outstanding. The exchange ratio at February 28, 2005 was 1.243 trust units per exchangeable share.

SELECTED ANNUAL INFORMATION

FINANCIAL (unaudited)

($ thousands, except per unit amounts)	2004	2003(2)	2002(2)
Revenue	**420,400**	403,022	372,037
Net income (loss) (1)	**13,763**	35,844	43,729
Per unit basic (1)	**0.22**	0.66	0.84
Per unit diluted (1)	**0.21**	0.62	0.82
Total assets	**1,104,136**	982,640	1,018,382
Total long-term financial liabilities	**216,583**	232,562	326,977
Cash distributions declared	**113,063**	33,382	—

(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). The application of this standard did not impact the 2002 financial information.

(2) The financial information for 2003 and 2002 has been restated for the adoption of the new accounting standards related to asset retirement obligations and transportation expenses.

Overall production for 2004 was 34,022 boe per day which represented a seven percent decrease from 36,686 boe per day in 2003. Average wellhead prices received during 2004 were $27.48 per boe compared to $28.07 during 2003. Production in 2002 was 39,214 boe per day. Average wellhead prices received in 2002 were $25.56 per boe. Total revenue for 2004 was $420.4 million compared to $403.0 million in 2003 and $372.0 million in 2002.

QUARTERLY INFORMATION

	2004				2003			
($ thousands, except per share amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
FINANCIAL (unaudited)								
Revenue	**111,521**	**108,216**	**104,517**	**96,146**	89,526	98,692	89,999	124,805
Cash flow from operations	**28,144**	**32,235**	**36,944**	**38,689**	30,179	19,975	33,372	54,707
Per unit basic	**0.44**	**0.51**	**0.59**	**0.63**	0.51	0.36	0.62	1.03
Per unit diluted	**0.42**	**0.49**	**0.57**	**0.60**	0.51	0.36	0.61	1.01
Cash distribution declared	**28,856**	**28,266**	**28,237**	**27,704**	25,344	8,038	—	—
Per unit	**0.45**	**0.45**	**0.45**	**0.45**	0.45	0.15	—	—
Net income (loss) (1)	**42,108**	**(12,554)**	**(11,213)**	**(4,578)**	8,490	(45,079)	40,329	32,104
Per unit basic (1)	**0.66**	**(0.20)**	**(0.18)**	**(0.07)**	0.14	(0.82)	0.75	0.60
Per unit diluted (1)	**0.65**	**(0.20)**	**(0.18)**	**(0.07)**	0.14	(0.84)	0.73	0.59

(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).

	2004				2003			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
PRODUCTION								
Conventional oil and NGLs (bbls/d)	**2,786**	**1,890**	**1,952**	**2,058**	1,982	1,989	2,167	2,969
Heavy oil (bbls/d)	**22,490**	**22,083**	**22,927**	**23,322**	24,400	25,123	22,816	23,278
Total oil and NGLs (bbls/d)	**25,276**	**23,973**	**24,879**	**25,380**	26,382	27,112	24,983	26,247
Natural gas (mmcf/d)	**55.5**	**50.9**	**57.2**	**56.0**	58.9	61.8	57.5	74.0
Barrels of oil equivalent (boe/d @ 6:1)	**34,525**	**32,454**	**34,411**	**34,709**	36,195	37,412	34,574	38,580
AVERAGE PRICES								
WTI oil (US$/bbl)	**48.28**	**43.88**	**38.32**	**35.15**	31.18	30.20	28.91	33.86
Edmonton par oil ($/bbl)	**57.72**	**56.32**	**50.59**	**45.59**	39.56	40.94	41.08	50.91
BTE light oil ($/bbl)	**50.46**	**52.63**	**47.55**	**43.50**	37.46	35.40	38.24	46.21
BTE heavy oil ($/bbl)	**31.24**	**34.69**	**29.21**	**26.29**	24.01	25.68	24.59	32.99
BTE total oil ($/bbl)	**33.35**	**36.11**	**30.63**	**27.70**	25.04	26.39	25.80	34.57
BTE natural gas ($/mcf)	**6.60**	**6.16**	**6.61**	**6.43**	5.56	5.79	6.21	7.17
BTE oil equivalent ($/boe)	**35.03**	**36.34**	**33.12**	**30.63**	27.34	28.69	29.02	37.39

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 annual 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 annual 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 registrant, 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; and

Date: March 29, 2005

Baytex Energy Trust
By: Baytex Energy Ltd

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

Exhibit 99.5

CERTIFICATIONS

I, Daniel G. Belot, Vice-President Finance and 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 annual 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 annual 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 registrant, 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; and

Date: March 29, 2005

Baytex Energy Trust
By: Baytex Energy Ltd.

By: (signed) "Daniel G. Belot"
Name: Daniel G. Belot
Title: Vice President Finance and
Chief Executive 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, 2004 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 Trust.

Baytex Energy Trust
by: Baytex Energy Ltd.

/s/RAYMOND T. CHAN
Raymond T. Chan
President & Chief Executive Officer

Dated at Calgary, Alberta, as of March 29, 2005

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, 2004 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Daniel G. Belot, Vice President, Finance and Chief Financial Officer of Baytex, 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.

Baytex Energy Trust
By: Baytex Energy Ltd.

/s/DANIEL G. BELOT
Daniel G. Belot
Vice President, Finance & Chief Financial Officer

Dated at Calgary, Alberta, as of March 29, 2005

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

We consent to the use of our reports dated March 7, 2005 (except as to note 20, which is as at March 22, 2005) (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 when there has been a restatement of the financial statements as described in note 20, and when there are changes in accounting principles that have a material effect on the comparability of the financial statements and changes in accounting principles that have been implemented in the financial statements such as described in note 3 to the consolidated financial statements), appearing in the Annual Report on Form 40-F of Baytex Energy Trust for the year ended December 31, 2004. .

/s/ “Deloitte & Touche LLP”

Independent Registered Chartered Accountants
Calgary, Alberta, Canada

March 29, 2005

Exhibit 99.9

Sproule ASSOCIATES LIMITED

Geological and Petroleum Engineering Consultants

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; Corporate Secretary*
D.W.C. Ho*, B.A.Sc., P.Eng., *Manager, Engineering*
K.P. McDonald, C.A., *Controller*
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.
H.J. Firla, B.S., P.Eng.
C.M.F. Galas, Ph.D., P.Eng.
C.J. Henderson, B.Eng., P.Eng.
B.F. Jose, M.Sc., P.Geoph.
P.B. Jung, B.S., 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.
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.

**Director*

Ref.: 2077.15303

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated February 28, 2005 and effective December 31, 2004, 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, 2004)", (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, 2004 dated March 21, 2005, 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 performed in connection with such Report.

Sincerely,

(signed) "Ken H. Crowther"

Ken H. Crowther, P.Eng.
President

Calgary, Alberta, Canada
March 29, 2005

KHC:PCS:dmm

900, 140 Fourth Ave SW; Calgary AB T2P 3N3 Canada; Tel: (403) 294-5500, Fax: (403) 294-5590
1675 Broadway, Suite 1130, Denver CO 80202 U.S.A.; Tel: (303) 592-8770, Fax: (303) 592-8771
Toll Free: 1-877-777-6135
info@sproule.com, www.sproule.com