UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 40-F

☐ **REGISTRATION STATEMENT PURSUANT TO SECTION 12 OF THE SECURITIES EXCHANGE ACT OF 1934**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13(a) OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended: December 31, 2011
Commission File Number: 001-32754

BAYTEX ENERGY CORP.

(Exact name of Registrant as specified in its charter)

Alberta	**1381**	**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)

2800, 520 - 3rd Avenue S.W.
Calgary, Alberta
T2P 0R3
(587) 952-3000
(Address and telephone number of registrant's principle executive offices)

Baytex Energy USA Ltd.
600 17th St., Suite 1600 S.
Denver, CO 80202
(303) 825-2777
(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:**
Common Shares	New York Stock Exchange Toronto Stock Exchange

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

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

For annual reports, indicate by check mark the information filed with this form:

☒ Annual Information Form ☒ 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:

117,892,573

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 ☒ No ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☐ No ☐

The Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the Registrant's Registration Statements under the Securities Act of 1933 on Form S-8 (File Nos. 333-163289 and 333-171568) and Form F-3 (File No. 333-171866) and the Registration Statement on Form F-10 and Form F-3 of the Company and Baytex Energy USA Ltd. (File Nos. 333-175796 and 333-175801).

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 40-F are forward-looking statements within the meaning of Section 21E of the Securities and Exchange Act of 1934, as amended (the "Exchange Act") and Section 27A of the Securities Act of 1933, as amended. Please see "Special Note Regarding Forward-Looking Statements" on page 4 of the Annual Information Form, which is Exhibit 99.1 of this Annual Report on Form 40-F.

Principal Documents

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

A. Annual Information Form

For the Registrant's Annual Information Form for the year ended December 31, 2011, see Exhibit 99.1 of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

For the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2011, including the report of its Independent Registered Chartered Accountants with respect thereto, see Exhibit 99.2 of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

For the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2011, see Exhibit 99.3 of this Annual Report on Form 40-F.

CONTROLS AND PROCEDURES

A. Certifications

The required disclosure is included in Exhibits 99.4, 99.5, 99.6 and 99.7 of this Annual Report on Form 40-F.

B. Disclosure Controls and Procedures

As of the year ended December 31, 2011, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the President and Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of the Registrant's "disclosure controls and procedures" as defined in Rule 13a-15(e) under Exchange Act. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the design and operation of the Registrant's disclosure controls and procedures were effective to ensure that the information required to be disclosed in the reports that the Registrant files or submits to the Securities and Exchange Commission is (i) recorded, processed, summarized and reported, within the required time periods; and (ii) accumulated and communicated to the Registrant's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief 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 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.

C. Management's Annual Report on Internal Control Over Financial Reporting

Management's Annual Report on Internal Control Over Financial Reporting is included in the Management's Report that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2011, filed as Exhibit 99.2 to this Annual Report on Form 40-F, and is incorporated herein by reference.

D. Attestation of Report of Independent Registered Chartered Accountants

The Attestation Report of the Registrant's Auditor is included in the Report of Independent Registered Chartered Accountants that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2011, filed as Exhibit 99.2 of this Annual Report of Form 40-F, and is incorporated herein by reference.

E. Changes in Internal Control Over Financial Reporting

During the year ended December 31, 2011, there were no changes in the Registrant's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Registrant's internal control over financial reporting.

AUDIT COMMITTEE FINANCIAL EXPERT

The Company's Board of Directors has determined that Mr. Naveen Dargan is an "audit committee financial expert" (as that term is defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its audit committee and is "independent" (as defined by the New York Stock Exchange corporate governance rules applicable to foreign private issuers). For a description of Mr. Dargan's relevant experience in financial matters, see the biographical description for Mr. Dargan under "Directors and Officers" in the Registrant's Annual Information Form for the year ended December 31, 2011, which is filed as Exhibit 99.1 to this Annual Report on Form 40-F.

CODE OF ETHICS

The Registrant has adopted a "code of ethics" (as that term is defined in paragraph 9(b) of General Instruction B to Form 40-F) ("Code of Ethics"), which is applicable to the directors, officers, employees and consultants of the Registrant and its affiliates (including, its principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions). The Code of Ethics is available on the Registrant's website at www.baytex.ab.ca.

In the past fiscal year, the Registrant has not amended any provision of its Code of Ethics that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F, or granted any waiver, including an implicit waiver, from any provision of its Code of Ethics.

PRINCIPAL ACCOUNTANT FEES AND SERVICES

The required disclosure is included under the heading "Audit Committee Information — External Auditor Service Fees" in the Registrant's Annual Information Form for the year ended December 31, 2011, filed as Exhibit 99.1 to this Annual Report on Form 40-F, and is incorporated herein by reference.

OFF-BALANCE SHEET ARRANGEMENTS

The Registrant does not have any "off-balance sheet arrangements" (as that term is defined in paragraph 11(ii) of General Instruction B to Form 40-F) that have or are reasonably likely to have a current or future effect on its financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that is material to investors.

TABULAR DISCLOSURE OF CONTRACTUAL OBLIGATIONS

The required disclosure is included under the heading "Liquidity and Capital Resources — Contractual Obligations" in the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2011, filed as Exhibit 99.3 to this Annual Report on Form 40-F, and is incorporated herein by reference.

IDENTIFICATION OF THE AUDIT COMMITTEE

The Company has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Company's Audit Committee members consist of Mr. N. Dargan, Mr. R.E.T. (Rusty) Goepel, and Mr. G. Melchin.

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

(1) The Registrant has previously filed a Form F-X in connection with the class of securities in relation to which the obligation to file this report arises.

(2) Any change to the name or address of a Registrant's agent for service shall be communicated promptly to the Commission by amendment to Form F-X referencing the file number of the Registrant.

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 report to be signed on its behalf by the undersigned, thereto duly authorized on March 15, 2012.

BAYTEX ENERGY CORP.

By: /s/ W. DEREK AYLESWORTH

Name: W. Derek Aylesworth
Title: Chief Financial Officer

FORM 40-F TABLE OF CONTENTS

Exhibit No.	Document
99.1	Annual Information Form of the Registrant for the fiscal year ended December 31, 2011.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2011 together with the Auditors' Report thereon.
99.3	Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2011.
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.

Use these links to rapidly review the document

EXHIBIT 99.1

BAYTEX ENERGY CORP.

ANNUAL INFORMATION FORM 2011

MARCH 15, 2012

TABLE OF CONTENTS

SELECTED TERMS

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

<u>Entities</u>

Baytex or the **Corporation** means Baytex Energy Corp., a corporation incorporated under the ABCA.

Baytex Commercial Trusts mean, collectively, Baytex Commercial Trust 1, Baytex Commercial Trust 2, Baytex Commercial Trust 3, Baytex Commercial Trust 4, Baytex Commercial Trust 5, Baytex Commercial Trust 6 and Baytex Commercial Trust 7.

Baytex Energy means Baytex Energy Ltd., a corporation amalgamated under the ABCA.

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

Baytex USA means Baytex Energy USA Ltd.

Board of Directors means the board of directors of Baytex.

NYMEX means the New York Mercantile Exchange, a commodity futures exchange.

OPEC means the Organization of the Petroleum Exporting Countries.

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

SEC means the United States Securities and Exchange Commission.

Shareholders mean the holders from time to time of Common Shares.

subsidiary has the meaning ascribed thereto in the *Securities Act* (Ontario) and, for greater certainty, includes all corporations, partnerships and trusts owned, controlled or directed, directly or indirectly, by us.

Trust means Baytex Energy Trust, a trust created under the laws of the Province of Alberta on July 24, 2003 pursuant to the Trust Indenture and which was dissolved into the Corporation on January 1, 2011 in connection with the Corporate Conversion.

we, **us** and **our** means Baytex and all its subsidiaries on a consolidated basis unless the context requires otherwise.

<u>Independent Engineering</u>

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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

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

Sproule Report means the report prepared by Sproule dated March 7, 2012 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2011*)".

<u>Securities and Other Terms</u>

2016 Debentures means our $150 million 9.15% series A senior unsecured debentures due August 26, 2016 and issued pursuant to the Debenture Indenture.

2021 Debentures means our US$150 million 6.75% series B senior unsecured debentures due February 17, 2021 and issued pursuant to the Debenture Indenture.

ABCA means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

Canadian GAAP means generally accepted accounting principles in Canada.

Common Shares means the common shares of Baytex.

Corporate Conversion means the internal reorganization of the Trust and certain of its subsidiaries which resulted in the conversion of the legal structure of the Trust from a trust to a corporation effective December 31, 2010 pursuant to a plan of arrangement under the ABCA.

Credit Facilities means, collectively, the $40 million extendible operating loan facility that Baytex Energy has with a chartered bank and the $660 million extendible syndicated loan facility that Baytex Energy has with a syndicate of chartered banks, each of which constitute a revolving credit facility for a three-year term (to June 14, 2014), which is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time).

Debenture Indenture means the amended and restated trust indenture among us, as issuer, Baytex Energy, Baytex Oil & Gas Ltd., Baytex Partnership, Baytex Marketing Ltd. and Baytex USA, as guarantors, and Valiant Trust Company, as indenture trustee, dated January 1, 2011, which is an amendment and restatement of a trust indenture dated August 26, 2009, as supplemented by a supplemental indenture dated February 17, 2011.

Debentures means, collectively, the 2016 Debentures and the 2021 Debentures.

Notes mean the unsecured subordinated promissory notes issued by Baytex Energy and certain other Operating Entities to us.

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

Trust Indenture means the third amended and restated trust indenture between Valiant Trust Company, and Baytex Energy dated May 20, 2008, as amended by a supplemental indenture dated December 31, 2010.

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

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
NGL	natural gas liquids	Mcf/d	thousand cubic feet per day
bbl/d	barrels per day	MMcf/d	million cubic feet per day
		m^3	cubic metres
		MMbtu	million British Thermal Units
		GJ	gigajoule

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

CONVERSIONS

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

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

CONVENTIONS

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

SPECIAL NOTES TO READER

Forward-Looking Statements

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

Specifically, this Annual Information Form contains forward-looking statements relating to: our business strategies, plans and objectives; the portion of our funds from operations to be allocated to our capital program; our ability to maintain production levels by investing approximately two-thirds of our internally generated funds from operations; our ability to grow our reserve base and add to production levels through exploration and development activities complemented by strategic acquisitions; our petroleum and natural gas reserves, including the quantum thereof and the present value of the future net revenue to be derived therefrom; the contingent resource estimates for our oil resource plays at Seal, northeast Alberta, North Dakota, Redwater and Kerrobert/Whiteside, including the quantum thereof and the present value of the future net revenue to be derived therefrom; development plans for our properties, including number of potential drilling locations, number of wells to be drilled in 2012, initial production rates from new wells and recovery factors; our light oil resource play at Kerrobert, including the development potential of the Viking formation; our steam-assisted gravity drainage project at Kerrobert, including resource potential of our undeveloped land, initial production rates from new wells and the number of potential drilling locations; our heavy oil resource play at Peace River, including the resource potential of our undeveloped land, initial production rates from new wells, the ability to recover incremental reserves using waterflood and cyclic steam recovery methods, our assessment of our cyclic steam stimulation pilot projects and the timing of commencing development of a 15-well thermal module; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates from new wells and average recoveries per well; our ability to utilize our tax pools to reduce our taxable income; our working interest production volume for 2012; the existence, operation and strategy of our risk management program; our dividend policy and level; funding sources for development capital expenditures and dividend payments; and the impact of existing and proposed governmental and environmental regulation. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

In addition, there are forward looking statements in this Annual Information Form under the heading "*Description of Our Business and Operations — Statement of Reserves Data and Other Oil and Gas Information*" (as to our reserves and future net revenues from our reserves, pricing and inflation rates, future development costs, the development of our proved undeveloped reserves and probable undeveloped reserves, future development costs, contingent resources, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates). Information and statements relating to reserves and resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in quantities predicted or estimated, and that the reserves and resources can be profitably produced in the future.

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

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: declines in oil and natural gas prices; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; access to external sources of capital; third party credit risk; a downgrade of our credit ratings; risks associated with the exploitation of our properties and our ability to acquire reserves; increases in operating costs; changes in government regulations that affect the oil and gas industry; risks relating to hydraulic fracturing; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with properties operated by third parties; risks associated with delays in business operations; risks associated with the marketing of our petroleum and natural gas production; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; expansion of our operations; the failure to realize anticipated benefits of acquisitions and dispositions or to manage growth; changes in climate change laws and other environmental, health and safety regulations; competition in the oil and gas industry for, among other things, acquisitions of reserves, undeveloped lands, skilled personnel and drilling and related equipment; the activities of our Operating Entities and their key personnel; depletion of our reserves; risks associated with securing and maintaining title to our properties; seasonal weather patterns; our permitted investments; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond the control of Baytex.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements. Readers should also carefully consider the matters discussed under the heading "*Risk Factors*" in this Annual Information Form.

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

Contingent Resource

This Annual Information Form contains estimates as of December 31, 2011 of the volumes of, and the net present value of the future net revenue from, the "contingent resource" for four of our oil resource plays: the Bluesky in the Seal area of Alberta; the Bakken/Three Forks in North Dakota; the Viking in southeast Alberta; and the Lloydminster area of Alberta. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resource" is not, and should not be confused with, petroleum and natural gas reserves. "Contingent resource" is defined in the Canadian Oil and Gas Evaluation Handbook as: "those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resource the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

A range of contingent resource estimates (low, best and high) were prepared by the independent qualified reserves evaluators. A low estimate (C1) is considered to be a conservative estimate of the quantity of the resource that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty (a 90% confidence level) that the actual quantities recovered will be equal or exceed the estimate. A best estimate (C2) is considered to be the best estimate of the quantity of the resource that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will be equal or exceed the estimate. A high estimate (C3) is considered to be an optimistic estimate of the quantity of the resource that will actually be recovered. It is unlikely that the actual remaining quantities of resource recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty (a 10% confidence level) that the actual quantities recovered will equal or exceed the estimate.

The primary contingencies which currently prevent the classification of the contingent resource as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; access to capital markets; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices; demonstration of economic viability; future drilling program and testing results; further reservoir delineation and studies; facility design work; limitations to development based on adverse topography or other surface restrictions; and the uncertainty regarding marketing and transportation of petroleum from development areas.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The estimates of contingent resource involve implied assessment, based on certain estimates and assumptions, that the resource described exists in the quantities predicted or estimated and that the resource can be profitably produced in the future. The net present value of the future net revenue from the contingent resource does not necessarily represent the fair market value of the contingent resource.

The recovery and resource estimates provided herein are estimates only. Actual contingent resource (and any volumes that may be reclassified as reserves) and future production from such contingent resource may be greater than or less than the estimates provided herein.

Description of Funds from Operations

This Annual Information Form contains references to funds from operations, which does not have any standardized meaning prescribed by Canadian GAAP. We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with Canadian GAAP, such as cash flow from operating activities and net income.

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

New York Stock Exchange

As a Canadian issuer listed on the New York Stock Exchange (the "**NYSE**"), we are not required to comply with most of the NYSE's corporate governance rules and listing standards and instead may comply with domestic corporate governance requirements. The NYSE requires that as a foreign private issuer we disclose any significant ways in which our corporate governance practices differ from those followed by U.S. domestic issuers. We have reviewed the NYSE corporate governance and listing standards applicable to U.S. domestic issuers and confirm that our corporate governance practices do not differ significantly from such standards.

Access to Documents

Any document referred to in this Annual Information and described as being accessible on the SEDAR website at *www.sedar.com* (including those documents referred to as being incorporated by reference in this Annual Information Form) may be obtained free of charge from us at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3.

BAYTEX ENERGY CORP.

General

We were incorporated on October 22, 2010 pursuant to the provisions of the ABCA, as an indirect wholly-owned subsidiary of the Trust, for the sole purpose of participating in a plan of arrangement under the ABCA to effect the conversion of the legal structure of the Trust from a trust to a corporation. The Corporate Conversion was implemented as a result of changes to laws regarding the taxation of trusts in Canada that took effect on January 1, 2011.

Pursuant to the Corporate Conversion: (i) on December 31, 2010, holders of Trust Units exchanged their Trust Units for Common Shares on a one-for-one basis; and (ii) on January 1, 2011, the Trust was dissolved and terminated, with the Corporation being the successor to the Trust.

Our head and principal office is located at Suite 2800, Centennial Place, East Tower, 520 - 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3. Our registered office is located at 1400, 350 - 7th Avenue S.W., Calgary, Alberta, Canada, T2P 3N9.

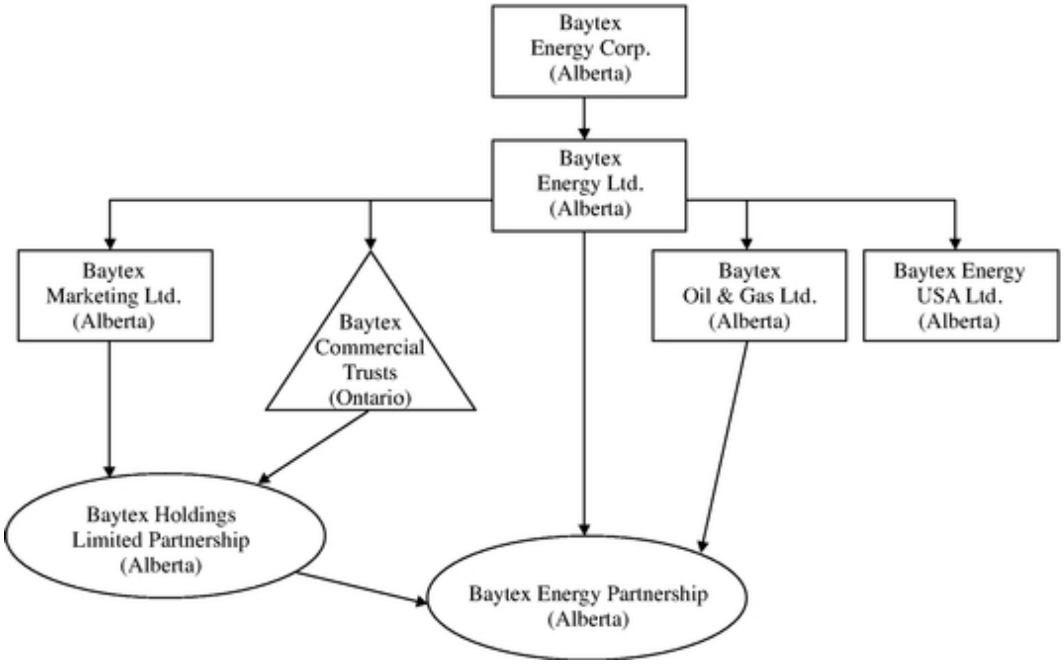
Inter-Corporate Relationships

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

	Percentage of voting securities (directly or indirectly)	Jurisdiction of Incorporation/ Formation
Baytex Energy Ltd.	100%	Alberta
Baytex Marketing Ltd.	100%	Alberta
Baytex Commercial Trusts	100%	Ontario
Baytex Oil & Gas Ltd.	100%	Alberta
Baytex Energy USA Ltd.	100%	Colorado
Baytex Holdings Limited Partnership	100%	Alberta
Baytex Energy Partnership	100%	Alberta

Our Organizational Structure

The following diagram describes the inter-corporate relationships among us and our material subsidiaries.



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

In this section, references to "we", "us" and "our" for events occurring prior to January 1, 2011 refer to the Trust and its subsidiaries on a consolidated basis, unless the context requires otherwise.

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

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

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

In November, 2009, we reached an agreement with our joint venture partner in the Bakken/Three Forks light oil resource play in the Williston Basin in northwest North Dakota to pre-pay the remaining deferred acquisition payments. The original participation agreement with the joint venture partner called for deferred acquisition payments totalling approximately US$36 million to be made prior to the

spud date of each of the remaining 24 earning wells, occurring more or less rateably until approximately January 2011. On December 15, 2009, we paid our joint venture partner US$33.2 million to complete the remaining deferred acquisition payments and to earn the right to operate a portion of the joint project area effective at the beginning of 2010.

On May 26, 2010, we completed the acquisition of a private company with heavy oil assets in the Lloydminster area of southwest Saskatchewan for aggregate net cash consideration of $40.9 million. The acquired assets were producing approximately 900 bbl/d of heavy oil at the time of the acquisition. The acquired assets included approximately 32,100 net acres of undeveloped land in close proximity to our existing assets in the Lloydminster area.

On September 30, 2010, we closed the sale of our 50% interest in the lands and wells comprising phase one of an in-situ combustion project located in the Kerrobert area of southwest Saskatchewan for $18 million and a gross overriding royalty on the divested lands. We retained our 50% interest in the area of mutual interest surrounding the phase one lands. Our other Kerrobert interests, including our 100% working interest in our steam-assisted gravity drainage project, were unaffected by the sale.

On December 31, 2010 / January 1, 2011, the Corporate Conversion was completed which resulted in holders of Trust Units exchanging their Trust Units for Common Shares on a one-for-one basis and the dissolution and termination of the Trust, with the Corporation being the successor to the Trust.

On February 3, 2011, we completed the acquisition of heavy oil assets located in the Reno area of northern Alberta and the Lloydminster area of western Saskatchewan. The total consideration for the acquisition of $159.3 million (net of adjustments) was funded by drawing on our revolving credit facilities.

On February 17, 2011, we completed a private placement of US$150 million principal amount of 6.75% series B senior unsecured debentures due February 17, 2021. The net proceeds of the offering were used to repay existing indebtedness under the credit facilities and for general corporate purposes.

On August 9, 2011, we completed the acquisition of natural gas assets located in the Brewster area of west central Alberta. The total consideration for the acquisition of $22.4 million (net of adjustments) was funded by drawing on our revolving credit facilities.

In the fourth quarter of 2011, we completed two dispositions of primarily undeveloped lands for $47.4 million. In the Kaybob South area of west central Alberta, we sold six sections of leasehold, including five sections with Duvernay rights, for $11.1 million. In the Dodsland area in southwest Saskatchewan, we sold 32,600 net acres of leasehold in the "halo" of the field for $36.3 million.

Significant Acquisitions

During the year ended December 31, 2011, we did not complete any acquisitions for which disclosure was required under Part 8 of National Instrument 51-102.

RISK FACTORS

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

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

Risks Relating to Our Business and Operations

Oil and natural gas prices are volatile. Declines in oil and natural gas prices will adversely affect our financial condition

Our revenues, operating results, profitability and future rate of growth depend primarily upon the prices we receive for the oil and natural gas that we sell. Prices also affect the amount of cash flow available for capital expenditures and dividends to Shareholders and our ability to borrow money or raise additional capital.

The extreme volatility of oil and natural gas prices over the past few years has affected the monthly distributions per Trust Unit paid by our predecessor, which reached a high of $0.25 for June to November 2008, before being reduced to $0.18 for December 2008 and January 2009 and $0.12 for February to November 2009. With the recovery in oil and natural gas prices, monthly distributions per Trust Unit were increased to $0.18 in December 2009 and to $0.20 in December 2010. Continuing strength in oil prices in 2011 allowed us to increase monthly dividends per Common Share to $0.22 in December 2011. Declines in oil and natural gas prices may result in declines in, or the elimination of, dividends to Shareholders.

Historically, oil and natural gas prices have been volatile and they are likely to continue to be volatile. Oil and natural gas prices are determined by economic factors and in the case of oil prices, political factors and a variety of additional factors beyond our control. These factors include economic conditions in the United States and Canada and worldwide including ongoing credit and liquidity concerns, the actions of OPEC, sanctions imposed on certain oil producing nations by other countries, governmental regulation, political instability or armed-conflict in the Middle East and other oil producing regions, weather conditions including weather-related disruptions to the North American natural gas supply, the foreign supply of oil and natural gas, risks of supply disruption, the level of consumer demand, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our proved and probable reserves, net asset value, borrowing capacity, revenues, profitability and funds from operations and ultimately on our financial condition and may, therefore, affect the amount of dividends that we pay to our Shareholders.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control.

The economics of producing from some wells may change as a result of lower commodity prices, which could result in reduced production of oil or natural gas and a reduction in the volumes of our reserves. We might also elect not to produce from certain wells at lower prices. Volatile oil and natural gas prices also make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

Variations in interest rates and foreign exchange rates could adversely affect our financial condition

There is a risk that the interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse impact on our financial condition, results of operations and future growth, potentially resulting in a decrease in dividends to Shareholders and/or the market price of the Common Shares.

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

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies in acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

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

We may manage the risk associated with changes in commodity prices by entering into petroleum or natural gas price hedges. If we hedge our commodity price exposure, we may forego some of the benefits we would otherwise experience if commodity prices were to increase. For more information in relation to our commodity hedging program, see "*Statement of Reserves Data and Other Oil and Natural Gas Information — Other Oil and Gas Information — Forward Contracts*". We may initiate certain hedges to attempt to mitigate the risk of the Canadian dollar appreciating against the U.S. dollar. An increase in the Canada/U.S. foreign exchange rate will impact future dividends and the future value of our reserves as determined by independent evaluators. These hedging activities could expose us to losses and to credit risk associated with counterparties with which we contract.

Uncertainty in the credit markets may restrict the availability or increase the cost of borrowing required for future development and acquisitions

Our future success depends in part on our ability to access capital markets and obtain financing on reasonable terms. Our ability to do so is dependent on a number of factors, many of which are beyond our control, including our credit ratings, interest rates, the structured and commercial financial markets and perceptions of us and the oil and natural gas exploration and production industry generally.

Uncertainty in domestic and international credit markets and other financial systems could materially affect our ability to access sufficient capital for our capital expenditures and acquisitions on reasonable terms, or at all, and, as a result, may have a material adverse effect on our ability to execute our business strategy and on our financial condition. There can be no assurance that financing will be available or sufficient to meet these requirements or for other corporate purposes or, if financing is available, that it will be on terms appropriate and acceptable to us. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

Our bank credit facilities will need to be renewed prior to June 14, 2014 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition

Our existing Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. We currently have Credit Facilities in the amount of $700 million. In the event that the Credit Facilities are not extended before June 14, 2014, indebtedness under the Credit Facilities will be repayable on June 14, 2014. The interest charged on the Credit Facilities is calculated based on a sliding scale ratio of our debt to EBITDA ratio. Repayment of all outstanding amounts under the Credit Facilities may be demanded on relatively short notice if an event of default occurs, which is continuing. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on our business, and dividends to Shareholders may be materially reduced. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms.

As at December 31, 2011, our outstanding indebtedness included $150 million of 2016 Debentures which mature on August 26, 2016 and US$150 million of 2021 Debentures which mature on February 17, 2021. We intend to fund these debt maturities with our existing Credit Facilities. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations and to pay dividends.

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

Amounts paid in respect of interest and principal on debt may reduce dividends to Shareholders. 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 dividends. Certain covenants in the agreements with our lenders under the Credit Facilities and the holders of the Debentures may also limit dividends. Although we believe the Credit Facilities will be sufficient for our immediate requirements, there can be no assurance that the amount will be adequate for our future financial obligations including our future capital expenditure program, or that we will be able to obtain additional funds.

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

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

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

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

Shareholders may suffer dilution in connection with future issuances of Common Shares. One of our objectives is to continually add to our reserves through acquisitions and through development. Our success is, in part, dependent on our ability to raise capital from time to time by selling additional Common Shares. Shareholders will suffer dilution as a result of these offerings if, for example, the cash flow, production or reserves from the acquired assets do not reflect the additional number of Common

Shares issued to acquire those assets. Shareholders may also suffer dilution in connection with future issuances of Common Shares to complete acquisitions.

If funds from operations are lower than expected or capital costs for these projects exceed current estimates, or if we incur major unanticipated expenses related to development or maintenance of our existing properties, we may be required to seek additional capital to maintain our capital expenditures at planned levels. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development of, or production from, our properties resulting in a decrease in the amount of funds from operations received by us and, therefore, may reduce dividends to Shareholders.

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

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

A downgrade our credit rating could increase our cost of capital and limit our access to capital, suppliers or counterparties.

Rating agencies regularly evaluate us, basing their ratings of our long-term and short-term debt on a number of factors. This includes our financial strength as well as factors not entirely within our control, including conditions affecting the oil and gas industry generally and the wider state of the economy. There can be no assurance that one or more of our credit ratings will not be downgraded.

Our borrowing costs and ability to raise funds are directly impacted by our credit ratings. Credit ratings may be important to suppliers or counterparties when they seek to engage in certain transactions, including transactions involving over-the-counter derivatives. A credit-rating downgrade could potentially impair our ability to enter into arrangements with suppliers or counterparties, to engage in certain transactions, and could limit our access to private and public credit markets and increase the costs of borrowing under our existing credit facilities. A downgrade could also limit our access to short-term debt markets, increase the cost of borrowing in the short-term and long-term debt markets, and trigger collateralization requirements related to physical and financial derivative liabilities with certain marketing counterparties and pipeline and midstream service providers.

In connection with certain over-the-counter derivatives contracts and other trading agreements, we could be required to provide additional collateral or to terminate transactions with certain counterparties in the event of a downgrade of our credit rating. The occurrence of any of the foregoing could adversely affect our ability to execute portions of our business strategy, including hedging, and could have a material adverse effect on our liquidity and capital position.

Our ability to add to our petroleum and natural gas reserves is highly dependent on our success in exploiting existing properties and acquiring additional reserves

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

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

Increases in operating costs could adversely affect our business, financial condition and results of operations

Higher operating costs for our underlying properties will directly decrease the amount of funds from operations received by us and, therefore, may reduce dividends to Shareholders. Labour costs, electricity, gas processing, well servicing and chemicals are examples of types of operating costs that are susceptible to material fluctuation. There is no assurance that further commercial quantities of petroleum and natural gas will be discovered or acquired by us.

Changes in government regulations that affect the oil and gas industry, or failing to comply with such regulations, could adversely affect us

The oil and gas industry in Canada and the United States is subject to federal, provincial, state and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the exportation of crude oil, natural gas and other products, as well as other matters. See "*Industry Conditions*".

The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights. We also rely on fresh water, which is obtained under government licenses to provide domestic and utility water for certain of our operations. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses.

Government regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse impact on us. In addition, failure to comply with government regulations may result in the suspension or termination of operations and subject us to liabilities and administrative, civil and criminal penalties. Compliance costs can be significant.

Hydraulic fracturing is subject to certain risks

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (natural gas and oil) production. The use of hydraulic fracturing is being used to produce commercial quantities of natural gas and oil from reservoirs that were previously unproductive. We use hydraulic fracturing in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay or increased operating costs or third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

Income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as resource allowance, may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders. Tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders.

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

We cannot assure you that income tax laws and government incentive programs relating to the oil and gas industry generally will not change in a manner that adversely affects the market price of the Common Shares.

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

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

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

Estimates of proved and probable reserves include undeveloped reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is still required before such wells begin production. Reserves may be recognized when plans are in place to make the required investments to convert these undeveloped reserves to producing. Circumstances such as a sustained decline in commodity prices or poorer than expected results from initial activities could cause a change in the investment or development plans which could result in a material change in our reserves estimates.

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

The contingent resource volumes included in this Annual Information Form are estimates only. The same uncertainties inherent in estimating quantities of reserves apply to estimating quantities of contingent resource. In addition, there are contingencies that prevent contingent resource from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent resource. Actual results may vary significantly from these estimates and such variances could be material.

Acquiring, developing and exploring for oil and natural gas involves many operating risks, which even a combination of experience, knowledge and careful evaluation may not be able to overcome. We have not insured and cannot fully insure against all risks related to our operations

Our business involves many operating risks related to the acquiring, developing and exploring for oil and natural gas. These risks include, but are not limited to, encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, equipment failures and other accidents, sour gas releases and spills, uncontrollable flows of oil, natural gas or well fluids, the invasion of water into producing formations, adverse weather conditions, pollution, other environmental hazards, fires, spills and delays in payments between parties caused by operation or economic matters which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment, personal injuries, loss of life and other hazards, all of which could result in liability. These risks will increase as we undertake more exploratory activity. Drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, the shut-in of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect upon our financial condition.

Exploration and development risks arise due to the uncertain results of searching for and producing petroleum and natural gas using imperfect scientific methods. Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations, prospects and our ability to maintain dividends to Shareholders.

The operation of a portion of our properties is largely dependent on the ability of third party operators, and harm to their business could cause delays and additional expenses in our receiving revenues

The continuing production from a property, and to some extent the marketing of production, is dependent upon the ability of the operators of our properties. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices. If, in situations where we are not the operator, the operator fails to perform these functions properly or becomes insolvent, revenues may be reduced. Revenues from production generally flow through the operator and, where we are not the operator, there is a risk of delay and additional expense in receiving such revenues.

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

The operation of wells located on properties not operated by us is generally governed by operating agreements which typically require the operator to conduct operations in a good and workman-like manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to us or our Shareholders. As owner of working interests in properties not operated by us, we will generally have a cause of action for damages arising from a breach of the operator's duty. Although not established by definitive legal precedent, it is unlikely that our Shareholders would be entitled to bring suit against third party operators to enforce the terms of the operating agreements. Therefore, our Shareholders will be dependent upon us, as owner of the working interest, to enforce such rights.

Delays in business operations could adversely affect our income and financial condition

Delays in business operations could adversely affect our income and financial condition and may affect our ability to pay dividends to Shareholders and the market price of our Common Shares. In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of our properties, and the delays of those operators in remitting payment to us, payments between any of these parties may also be delayed by:

- restrictions imposed by lenders;
- accounting delays;
- delays in the sale or delivery of products;
- delays in the connection of wells to a gathering system;
- restrictions due to limited pipeline or processing capacity;
- operational problems affecting pipelines and facilities;
- blowouts or other accidents;
- adjustments for prior periods;
- recovery by the operator of expenses incurred in the operation of the properties; or
- the establishment by the operator of reserves for these expenses.

Any of these delays could reduce the amount of cash available to pay dividends to Shareholders in a given period and expose us to additional third party credit risks.

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

These factors include demand for petroleum and natural gas, market fluctuations, the availability, proximity and capacity of oil and natural gas pipelines and processing and storage facilities and government regulations, including regulations relating to environmental protection, royalties, allowable production, pricing, taxes, importing and exporting of oil and natural gas and political events throughout the world that cause disruptions in the supply of oil. Any particular event could result in a material decline in prices and therefore result in a reduction of our net production revenue. The availability of markets is beyond our control.

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

The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems some of which we do not own. Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has recently resulted in significantly lower amounts being realized by Canadian producers compared with the WTI price for crude oil. The lack of access to capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and

facilities, as well as any delays in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition.

Certain pipeline leaks in 2011have gained media and other stakeholder attention and may result in additional regulation or changes in law which could impede the conduct of our business or make our operations more expensive.

A portion our production may, from time to time, be processed through facilities owned by third parties and which we do not have control of. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

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

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

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the availability of, and the ability to acquire, water supplies needed for drilling and hydraulic fracturing, or our ability to dispose of water used or removed from strata at a reasonable cost and within applicable environmental regulations;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and gas industry by various levels of government and governmental agencies.

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

Our heavy oil projects face additional risks compared to conventional oil and gas production

Some of our heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as cyclic steam stimulation and steam-assisted gravity drainage, are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the

reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on cyclic steam stimulation, steam-assisted gravity drainage or other new technologies to become uneconomical, which could have a negative effect on our financial condition. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

The operating costs of our heavy oil projects have the potential to vary considerably throughout the operating period and will be significant components of the cost of production of any petroleum products produced. Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation: labor costs; the cost of catalyst and chemicals; the cost of natural gas and electricity; power outages; produced sand causing issues of erosion, hot spots and corrosion; reliability of and maintenance cost of facilities; and the cost to transport sales products and the cost to dispose of certain by-products.

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

Our operations and expertise are currently primarily focused on oil and gas production and development in western Canada and the United States. In the future, we may acquire oil and gas properties outside of these geographic areas. In addition, we could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, or an interest in an oil sands project. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may adversely affect our business, financial condition or results of operations.

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

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

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

The price we pay for the purchase of any material properties is based on several criteria, including engineering and economic assessments made by independent engineers modified to reflect our technical and economic views. These assessments include a series of assumptions regarding such factors as recoverability and marketability of petroleum and natural gas, future prices of petroleum and natural gas, future operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond our control. All such assessments involve a measure of geologic and engineering uncertainty which could result in lower than anticipated production and reserves. Consequently, the reserves acquired may be less than expected, which could adversely impact cash flow from operating activities and dividends to Shareholders.

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

Climate change laws and related environmental, health and safety regulation may impose restrictions or costs on our business which may adversely affect our financial condition and our ability to maintain dividends

Nearly all aspects of our operations are subject to environmental, health and safety regulation pursuant to a variety of federal, provincial, state and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. A breach of such legislation may result in the imposition of fines or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Furthermore, management believes the political climate appears to favour new programs for environmental laws and regulation, particularly in relation to the reduction of emissions or emissions intensity, and there is no assurance that any such programs, laws or regulations, if proposed and enacted, will not contain emission reduction targets which we cannot meet, and financial penalties or charges could be incurred as a result of the failure to meet such targets. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions — Climate Change Regulation*".

There has been much public and political debate with respect to the strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies by either the provinces or states in which we operate our business or by the governments of Canada or the United States, and whether to meet international agreed limits, or as otherwise determined, for reducing greenhouse gases could have a material impact on the nature of oil and natural gas operations, including ours. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on us and our operations and financial condition. Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated environmental and reclamation obligations, there can be no assurance that we will be able to satisfy our actual future environmental and reclamation obligations from such funds.

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

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

There are numerous companies in the oil and gas industry who are competing with us for the acquisitions of properties with longer life reserves, properties with exploitation and development opportunities and undeveloped land. As a result of such competition, it may be more difficult for us to acquire reserves on beneficial terms or at all. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a world-wide basis and, as such, have greater technical, financial and operational resources than us.

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

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

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

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

We depend entirely on our management with respect to the acquisition of oil and gas properties, the development and acquisition of additional reserves, the management and administration of all matters relating to our properties, including the safekeeping of our primary workspace and computer systems. The loss of the services of key personnel may have a material adverse effect on our business, financial condition, results of operations and prospects. The contributions of the existing management team to our immediate and near term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

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

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

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

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

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

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

Although title reviews are conducted prior to any purchase of significant resource assets, such reviews cannot guarantee that an unforeseen defect in the chain of title will not arise to defeat our title to certain assets. There may be valid challenges to title, or proposed legislative changes which affect title to the oil and natural gas properties that we control, that, if successful or made into law, could impair our activities on them and result in a reduction in the amount of funds from operations, possibly resulting in lower dividends to our Shareholders which could result in a lower market price of the Common Shares.

We are affected by seasonal weather patterns

The level of activity in the oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities, provincial and state transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for crude oil and natural gas.

Our permitted investments may be risky

An investment in us should be made with the understanding that the value of any of our investments may fluctuate in accordance with changes in the financial condition of such investments, the value of similar securities, and other factors. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Investments in energy-related 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 our Common Shares could be affected by adverse changes in the market values of such investments.

Risks Relating to Ownership of Securities

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

The amount of future cash dividends, if any, will be subject to the discretion of our Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the ABCA for the declaration and payment of dividends. Depending on these and various other factors, many of which will be beyond the control of our Board of Directors and management team, we will change our dividend policy from time to time and, as a result, future cash dividends could be reduced or suspended entirely. The market value of our Common Shares may deteriorate if we reduce or suspend the amount of the cash dividends that we pay in the future and such deterioration may be material. Furthermore, the future treatment of dividends for tax purposes will be subject to the nature and composition of our dividends and potential legislative and regulatory changes.

Dividends may be reduced during periods of lower funds from operations, which result from lower commodity prices and the decision by us to finance capital expenditures using funds from operations. A reduction in dividends could also negatively affect the market price of the Common Shares.

Production and development costs incurred with respect to properties, including power costs and the costs of injection fluids associated with tertiary recovery operations, reduce the income that we receive and, consequently, the amounts we can distribute to our Shareholders.

The timing and amount of capital expenditures will directly affect the amount of income available to pay dividends to our Shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are planned. To the extent that external sources of capital, including the issuance of additional Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand petroleum and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash we receive will be reduced, resulting in reductions to the amount of cash we are able to distribute to our Shareholders. A reduction in the amount of cash distributed to Shareholders may negatively affect the market price of the Common Shares.

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates and the comparability of the Common Shares to other yield-oriented securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

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

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

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

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

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

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

We also included in this Annual Information Form estimates of contingent resources. Contingent resources represent the quantity of petroleum and natural gas estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. The SEC does not permit the inclusion of estimates of resources in reports filed with it by United States companies.

There is additional taxation applicable to non-residents

The Tax Act imposes a withholding tax at the rate of 25% on the dividends or other property paid by us to Shareholders who are non-residents of Canada, unless the rate is reduced under the provisions of a tax treaty between Canada and the non-resident Shareholder's jurisdiction of residence. These taxes may change from time to time. Where the non-resident Shareholder is a United States resident entitled to benefits under the Canada-United States Income Tax Convention, 1980and is the beneficial owner of the dividends, the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%. Additionally, the reduced rates of taxation on qualified dividend income under current U.S. tax laws are scheduled to expire at the end of 2012 and there is no assurance that the reduced tax rates will be re-enacted in the future.

There is a foreign exchange risk for non-resident Shareholders

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

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

Overview

Through our subsidiaries, we are engaged in the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets in Canada (primarily in the provinces of British Columbia, Alberta and Saskatchewan) and in the United States (primarily in the states of North Dakota and Wyoming). We act as the primary financing vehicle for our subsidiaries by providing access to debt and equity capital markets. As at the date of this Annual Information Form, our primary assets are the shares of Baytex Energy that we own and the Notes. Cash flow from the business carried on by our subsidiaries is flowed to us by way of dividends and interest and principal repayments on the Notes.

We pay monthly cash dividends to holders of our Common Shares in accordance with our dividend policy. In the event that we do not comply with covenants under the Credit Facilities and the Debenture Indenture, our ability to pay dividends to Shareholders may be restricted. See "*Description of Capital Structure — Dividend Policy*".

Baytex Energy Ltd.

Baytex Energy is a corporation amalgamated under the ABCA and is actively engaged in the business of oil and natural gas exploration, exploitation, development, acquisition and production in Canada. Baytex Energy acts as the managing partner of Baytex Partnership. Baytex Energy is a wholly-owned subsidiary of the Corporation.

Baytex Energy Partnership

Baytex Partnership is a general partnership governed by the laws of the Province of Alberta. As at the date of this Annual Information Form, the partners of Baytex Partnership are Baytex Energy, Baytex Holdings Limited Partnership and Baytex Oil & Gas Ltd. Baytex Partnership holds the material operating assets in Canada from which we generate cash flow.

Baytex Energy USA Ltd.

Baytex USA is a corporation incorporated under the laws of the State of Colorado and is actively engaged in the business of oil and natural gas exploration, exploitation, development, acquisition and production in the United States. Baytex USA holds all of the operating assets in the United States from which we generate cash flow. Baytex USA is a wholly-owned subsidiary of Baytex Energy.

Personnel

As at December 31, 2011, we had 159 employees in our Calgary head office, 18 employees in our Denver office and 52 employees in our field operations.

Notes

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

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated December 31, 2011. The statement is effective as of December 31, 2011 and the preparation date of the statement by Sproule is March 7, 2012. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Sproule in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2011 as contained in the Sproule Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any hedging activities. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101. Sproule was engaged by us to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. See also "*Definitions and Other Notes to Reserve Data Tables*" below.

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

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

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED:						
Developed Producing	4,746.3	3,945.7	41,739.7	34,948.7	1,844.5	1,321.8
Developed Non-Producing	425.7	355.5	12,355.8	10,329.3	110.5	76.6
Undeveloped	5,180.1	4,531.4	53,998.1	46,471.3	986.4	716.9
TOTAL PROVED	10,352.1	8,832.6	108,093.6	91,749.3	2,941.4	2,115.3
PROBABLE	7,039.6	6,028.3	71,150.6	59,169.0	1,528.7	1,091.5
TOTAL PROVED PLUS PROBABLE	17,391.6	14,860.9	179,244.2	150,918.3	4,470.1	3,206.8

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	55,159	47,679	57,523.7	48,162.7
Developed Non-Producing	3,432	2,890	13,464.0	11,243.1
Undeveloped	16,978	13,306	62,994.3	53,937.3
TOTAL PROVED	75,569	63,876	133,981.9	113,343.2
PROBABLE	34,281	28,218	85,432.4	70,991.8
TOTAL PROVED PLUS PROBABLE	109,850	92,094	219,414.2	184,335.0

UNITED STATES

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED:						
Developed Producing	3,672.6	3,008.8	—	—	—	—
Developed Non-Producing	380.0	308.8	—	—	—	—
Undeveloped	13,819.3	11,560.7	—	—	2,824.9	2,415.3
TOTAL PROVED	17,871.9	14,878.4	—	—	2,824.9	2,415.3
PROBABLE	7,970.7	6,627.6	—	—	1,327.9	1,135.3
TOTAL PROVED PLUS PROBABLE	25,842.5	21,506.0	—	—	4,152.8	3,550.6

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	167	136	3,700.4	3,031.5
Developed Non-Producing	—	—	380.0	308.8
Undeveloped	11,133	9,519	18,499.7	15,562.5
TOTAL PROVED	11,300	9,655	22,580.1	18,902.9
PROBABLE	5,291	4,522	10,180.4	8,516.6
TOTAL PROVED PLUS PROBABLE	16,592	14,177	32,760.6	27,419.5

TOTAL

RESERVES CATEGORY	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)
PROVED:						
Developed Producing	8,418.9	6,954.6	41,739.7	34,948.7	1,844.5	1,321.8
Developed Non-Producing	805.6	664.3	12,355.8	10,329.3	110.5	76.6
Undeveloped	18,999.4	16,092.1	53,998.1	46,471.3	3,811.3	3,132.2
TOTAL PROVED	28,223.9	23,710.9	108,093.6	91,749.3	5,766.3	4,530.6
PROBABLE	15,010.3	12,655.9	71,150.6	59,169.0	2,856.5	2,226.9
TOTAL PROVED PLUS PROBABLE	43,234.2	36,366.8	179,244.2	150,918.3	8,622.9	6,757.4

RESERVES CATEGORY	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	55,326	47,815	61,224.1	51,194.3
Developed Non-Producing	3,432	2,890	13,843.9	11,551.9
Undeveloped	28,112	22,825	81,494.1	69,499.8
TOTAL PROVED	86,870	73,531	156,562.1	132,246.0
PROBABLE	39,572	32,740	95,612.7	79,508.5
TOTAL PROVED PLUS PROBABLE	126,442	106,271	252,174.8	211,754.5

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

CANADA

	BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	2,068,777	1,754,438	1,540,278	1,384,356	1,265,207
Developed Non-Producing	493,250	375,084	294,198	236,801	194,805
Undeveloped	2,109,414	1,494,155	1,099,290	837,308	655,231
TOTAL PROVED	4,671,441	3,623,677	2,933,766	2,458,465	2,115,243
PROBABLE	3,339,190	2,144,653	1,492,851	1,101,823	849,827
TOTAL PROVED PLUS PROBABLE	8,010,631	5,768,330	4,426,617	3,560,288	2,965,070

UNITED STATES

RESERVES CATEGORY					
PROVED:					
Developed Producing	176,373	131,627	106,529	90,611	79,623
Developed Non-Producing	17,940	13,293	10,651	8,948	7,756
Undeveloped	597,163	310,136	174,935	102,098	59,361
TOTAL PROVED	791,475	455,056	292,115	201,657	146,740
PROBABLE	545,716	198,609	97,531	56,470	35,542
TOTAL PROVED PLUS PROBABLE	1,337,191	653,665	389,646	258,127	182,281

TOTAL

RESERVES CATEGORY					
PROVED:					
Developed Producing	2,245,149	1,886,065	1,646,807	1,474,966	1,344,829
Developed Non-Producing	511,190	388,377	304,848	245,749	202,561
Undeveloped	2,706,576	1,804,291	1,274,225	939,406	714,592
TOTAL PROVED	5,462,915	4,078,732	3,225,881	2,660,122	2,261,982
PROBABLE	3,884,906	2,343,263	1,590,382	1,158,294	885,369
TOTAL PROVED PLUS PROBABLE	9,347,822	6,421,995	4,816,263	3,818,415	3,147,351

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,531,164	1,298,209	1,139,767	1,024,596	936,723
Developed Non-Producing	355,176	268,970	210,204	168,641	138,315
Undeveloped	1,563,681	1,085,981	783,020	582,733	443,936
TOTAL PROVED	3,450,020	2,653,160	2,132,991	1,775,971	1,518,974
PROBABLE	2,468,655	1,579,698	1,092,536	800,434	612,572
TOTAL PROVED PLUS PROBABLE	5,918,675	4,232,858	3,225,527	2,576,405	2,131,546

UNITED STATES

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	167,377	124,931	101,123	86,023	75,601
Developed Non-Producing	17,016	12,607	10,099	8,483	7,352
Undeveloped	469,957	247,910	141,122	82,469	47,475
TOTAL PROVED	654,349	385,447	252,343	176,975	130,429
PROBABLE	414,887	151,665	75,020	43,755	27,670
TOTAL PROVED PLUS PROBABLE	1,069,236	537,113	327,363	220,730	158,099

TOTAL

RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,698,541	1,423,140	1,240,890	1,110,619	1,012,324
Developed Non-Producing	372,192	281,577	220,303	177,124	145,667
Undeveloped	2,033,638	1,333,891	924,142	665,202	491,411
TOTAL PROVED	4,104,369	3,038,607	2,385,334	1,952,946	1,649,403
PROBABLE	2,883,542	1,731,363	1,167,556	844,189	640,242
TOTAL PROVED PLUS PROBABLE	6,987,911	4,769,971	3,552,890	2,797,135	2,289,645

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

TOTAL PROVED RESERVES	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	WELL ABANDONMENT COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Canada	9,773,531	1,406,703	2,770,607	772,540	152,242	4,671,441	1,221,421	3,450,020
United States	2,108,730	604,576	389,936	322,743	—	791,475	137,126	654,349
Total	11,882,260	2,011,279	3,160,544	1,095,283	152,242	5,462,915	1,358,547	4,104,369
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	16,652,220	2,463,324	4,889,196	1,098,643	190,425	8,010,631	2,091,956	5,918,675
United States	3,359,387	965,500	681,782	374,915	—	1,337,191	267,956	1,069,236
Total	20,011,607	3,428,824	5,570,978	1,473,558	190,425	9,347,822	2,359,912	6,987,911

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/boe)[(1)]
CANADA			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	270,323	30.04
	Heavy Oil (including solution gas and other by-products)	2,487,726	27.02
	Natural Gas (including by-products but excluding natural gas from oil wells)	175,717	14.30
	Total Canada	2,933,766	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	401,609	26.68
	Heavy Oil (including solution gas and other by-products)	3,765,154	24.88
	Natural Gas (including by-products but excluding natural gas from oil wells)	259,855	14.46
	Total Canada	4,426,618	
UNITED STATES			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	292,115	15.45
	Heavy Oil (including solution gas and other by-products)	—	—
	Natural Gas (including by-products but excluding natural gas from oil wells)	—	—
	Total United States	292,115	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	389,646	14.21
	Heavy Oil (including solution gas and other by-products)	—	—
	Natural Gas (including by-products but excluding natural gas from oil wells)	—	—
	Total United States	389,646	
TOTAL			
Proved	Light and Medium Crude Oil (including solution gas and other by-products)	562,437	20.16
	Heavy Oil (including solution gas and other by-products)	2,487,726	27.02
	Natural Gas (including by-products but excluding natural gas from oil wells)	175,717	14.30
	Total	3,225,881	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and other by-products)	791,255	18.65
	Heavy Oil (including solution gas and other by-products)	3,765,154	24.88
	Natural Gas (including by-products but excluding natural gas from oil wells)	259,855	14.46
	Total	4,816,264	

Note:

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

Definitions and Notes to Reserves Data Tables

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

1. "**Gross**" means:

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

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

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

2. "**Net**" means:

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

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

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

3. Definitions used for reserve categories are as follows:

    Reserve Categories

    Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

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

    (b) the use of established technology; and

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

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

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

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

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

    Development and Production Status

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

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

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

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

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

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

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

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

   (c) dry hole contributions and bottom hole contributions;

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

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

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

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

   These are prices and costs that are:

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

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

10. Numbers may not add due to rounding.

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

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

    In Canadian Securities Administrators Staff Notice 51-324, "Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities" bitumen is defined as:

    > "A naturally occurring viscous mixture consisting mainly of pentanes and heavier hydrocarbons. Its viscosity is greater than 10,000 mPa-s (cp) measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis. Crude bitumen may contain sulphur and other non-hydrocarbon compounds."

Paragraphs 1.1(u) and 1.1(v) of NI 51-101 clarify that bitumen would be recovered by non-conventional oil and gas activities.

Almost all the oil we produce at Seal has a viscosity greater than 10,000 mPa-s (cp) measured at original temperature in the reservoir and atmospheric pressure, on a gas-free basis. We currently produce almost all of our oil at Seal by conventional oil and gas activities, drilling horizontal wells, recovering the oil by primary recovery, as the oil flows to our wells in its native state. Much of our oil produced by conventional oil and gas activities at Seal is classed as "ultra-heavy" oil for the purposes of paying Crown royalties. By calling this oil produced by conventional methods "heavy oil", we provide investors with a clearer and more logical description of our oil and gas activities.

We have classified the oil that would be produced from our non-conventional thermal in-situ projects at Seal as "bitumen". By calling this oil produced by non-conventional methods "bitumen", we provide investors with a clearer and more logical description of our oil and gas activities.

With respect to our permanent steam project at Seal, Alberta, as of December 31, 2011, Sproule attributed gross proved developed producing bitumen reserves of 1,583.6 Mbbl and gross proved undeveloped bitumen reserves of 6,892.1 Mbbl, which equates to gross total proved bitumen reserves of 8,475.7 Mbbl. As a comparison, as of December 31, 2010, Sproule attributed gross proved undeveloped bitumen reserves of 5,109.1 Mbbl to this project and there was no attribution to the proved developed producing category. As of December 31, 2011, Sproule attributed gross proved plus probable developed producing bitumen reserves of 3,292.9 Mbbl and gross proved plus probable undeveloped bitumen reserves of 29,626.9 Mbbl, which equates to gross total proved plus probable bitumen reserves of 32,919.8 Mbbl. As a comparison, as of December 31, 2010, Sproule attributed gross proved plus probable undeveloped bitumen reserves of 30,335.6 Mbbl to this project and there was no attribution to the proved plus probable developed producing category.

After deducting the volumes of gross bitumen reserves, Sproule's estimates of our total gross proved heavy oil reserves were 99,617.9 Mbbl, and its estimates of our total gross proved plus probable heavy oil reserves were 146,324.4 Mbbl as of December 31, 2011.

13. On March 11, 2010, the Alberta government announced changes to Alberta's royalty system intended to increase Alberta's competitiveness in the oil and gas industry, which included a decrease in the maximum royalty rates for conventional oil and natural gas production effective for the January 2011production month and certain temporary incentive programs currently in place being made permanent. See "*Industry Conditions*".

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2011, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2011

	OIL			NATURAL GAS		
	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Hardisty Lloydblend 20.5° API ($Cdn/bbl)	AECO-C ($Cdn/MMbtu)	INFLATION RATES(1) %/year	EXCHANGE RATE(2) ($US/$Cdn)
Historical						
2007	72.27	77.06	51.93	6.65	2.0	0.935
2008	99.59	102.85	82.58	8.15	1.1	0.943
2009	61.63	66.20	58.49	4.19	2.0	0.880
2010	79.43	77.80	67.17	4.16	1.2	0.971
2011	95.00	95.16	77.09	3.72	1.5	1.012
Est Forecast						
2012	98.07	96.87	82.34	3.16	2.0	1.012
2013	94.90	93.75	79.69	3.78	2.0	1.012
2014	92.00	90.89	77.25	4.13	2.0	1.012
2015	97.42	96.23	81.80	5.53	2.0	1.012
2016	99.37	98.16	83.44	5.65	2.0	1.012
Thereafter				Escalation Rate of 2%		

Notes:

(1) Inflation rates for forecasting prices and costs.

(2) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average prices realized by us for the year ended December 31, 2011, excluding hedging activities, were $65.53/bbl for heavy oil, $82.49/bbl for light oil and NGL and $4.17/Mcf for natural gas.

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

CANADA	LIGHT AND MEDIUM OIL Proved (Mbbl)	LIGHT AND MEDIUM OIL Probable (Mbbl)	LIGHT AND MEDIUM OIL Proved Plus Probable (Mbbl)	HEAVY OIL Proved (Mbbl)	HEAVY OIL Probable (Mbbl)	HEAVY OIL Proved Plus Probable (Mbbl)
December 31, 2010	10,316.8	6,535.2	16,852.0	104,978.1	62,435.4	167,413.5
Extensions	2,726.6	2,443.4	5,170.0	9,477.0	7,929.4	17,406.4
Improved Recovery	—	—	—	3,191.0	3,409.2	6,600.2
Technical Revisions	(729.8)	(1,066.4)	(1,796.2)	(2,872.5)	(6,701.1)	(9,573.6)
Discoveries	—	—	—	51.3	16.9	68.2
Acquisitions	—	—	—	6,221.6	4,030.6	10,252.2
Dispositions	(547.9)	(863.6)	(1,411.5)	—	—	—
Economic Factors	(33.3)	(9.1)	(42.4)	(85.8)	30.2	(55.6)
Production	(1,380.3)	—	(1,380.3)	(12,867.1)	—	(12,867.1)
December 31, 2011	10,352.1	7,039.6	17,391.6	108,093.6	71,150.6	179,244.2

CANADA	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Proved (MMcf)	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Probable (MMcf)	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Proved Plus Probable (MMcf)	NATURAL GAS LIQUIDS Proved (Mbbl)	NATURAL GAS LIQUIDS Probable (Mbbl)	NATURAL GAS LIQUIDS Proved Plus Probable (Mbbl)
December 31, 2010	78,182	33,580	111,762	2,824.6	1,215.2	4,039.8
Extensions	12,520	6,579	19,099	797.2	585.0	1,382.2
Improved Recovery	21	5	26	—	—	—
Technical Revisions	(1,217)	(8,293)	(9,510)	(457.7)	(425.7)	(883.4)
Discoveries	—	—	—	—	—	—
Acquisitions	8,565	3,348	11,913	457.9	173.1	631.0
Dispositions	(240)	(13)	(253)	—	—	—
Economic Factors	(4,516)	(926)	(5,442)	(76.5)	(18.9)	(95.4)
Production	(17,745)	—	(17,745)	(604.1)	—	(604.1)
December 31, 2011	75,570	34,281	109,850	2,941.4	1,528.7	4,470.1

CANADA	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2010	131,149.8	75,782.3	206,932.3
Extensions	15,087.5	12,054.3	27,141.8
Improved Recovery	3,194.5	3,410.0	6,604.5
Technical Revisions	(4,262.8)	(9,575.4)	(13,838.2)
Discoveries	51.3	16.9	68.2
Acquisitions	8,107.0	4,761.7	12,868.7
Dispositions	(587.9)	(865.8)	(1,453.7)
Economic Factors	(948.3)	(152.1)	(1,100.4)
Production	(17,809.0)	—	(17,809.0)
December 31, 2011	133,982.1	85,432.0	219,414.1

UNITED STATES	LIGHT AND MEDIUM OIL			ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2010	8,099.2	11,407.5	19,506.6	5,643	9,873	15,516
Extensions	6,035.3	2,855.2	8,890.5	2	1	3
Improved Recovery	—	—	—	—	—	—
Technical Revisions	4,227.9	(6,281.2)	(2,053.3)	5,678	(4,578)	1,100
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	(4.4)	(10.8)	(15.2)	(4)	(4)	(8)
Production	(486.1)	—	(486.1)	(19)	—	(19)
December 31, 2011	17,871.9	7,970.6	25,842.5	11,300	5,292	16,592

UNITED STATES	NATURAL GAS LIQUIDS			OIL EQUIVALENT		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2010	—	—	—	9,039.7	13,052.9	22,092.6
Extensions	—	—	—	6,035.6	2,855.4	8,891.0
Improved Recovery	—	—	—	—	—	—
Technical Revisions	2,824.9	1,327.9	4,152.8	7,999.1	(5,716.3)	2,282.8
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	—	—	(5.1)	(11.5)	(16.5)
Production	—	—	—	(489.3)	—	(489.3)
December 31, 2011	2,824.9	1,327.9	4,152.8	22,580.1	10,180.5	32,760.6

TOTAL	LIGHT AND MEDIUM OIL Proved (Mbbl)	LIGHT AND MEDIUM OIL Probable (Mbbl)	LIGHT AND MEDIUM OIL Proved Plus Probable (Mbbl)	HEAVY OIL Proved (Mbbl)	HEAVY OIL Probable (Mbbl)	HEAVY OIL Proved Plus Probable (Mbbl)
December 31, 2010	18,416.0	17,942.7	36,358.7	104,978.1	62,435.4	167,413.5
Extensions	8,761.9	5,298.6	14,060.5	9,477.0	7,929.4	17,406.4
Improved Recovery	—	—	—	3,191.0	3,409.2	6,600.2
Technical Revisions	3,498.1	(7,347.7)	(3,849.6)	(2,872.5)	(6,701.1)	(9,573.6)
Discoveries	—	—	—	51.3	16.9	68.2
Acquisitions	—	—	—	6,221.6	4,030.6	10,252.2
Dispositions	(547.9)	(863.6)	1,411.5)	—	—	—
Economic Factors	(37.7)	(19.9)	(57.6)	(85.8)	30.2	(55.6)
Production	(1,866.4)	—	(1,866.4)	(12,867.1)	—	(12,867.1)
December 31, 2011	28,223.9	15,010.3	43,234.2	108,093.6	71,150.6	179,244.2

TOTAL	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Proved (MMcf)	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Probable (MMcf)	ASSOCIATED, NON-ASSOCIATED AND SOLUTION GAS Proved Plus Probable (MMcf)	NATURAL GAS LIQUIDS Proved (MMcf)	NATURAL GAS LIQUIDS Probable (MMcf)	NATURAL GAS LIQUIDS Proved Plus Probable (MMcf)
December 31, 2010	83,825	43,453	127,278	2,824.6	1,215.2	4,039.8
Extensions	12,522	6,580	19,102	797.2	585.0	1,382.2
Improved Recovery	21	5	26	—	—	—
Technical Revisions	4,461	(12,871)	(8,410)	2,367.2	902.2	3,269.4
Discoveries	—	—	—	—	—	—
Acquisitions	8,565	3,348	11,913	457.9	173.1	631.0
Dispositions	(240)	(13)	(253)	—	—	—
Economic Factors	(4,520)	(930)	(5,450)	(76.5)	(18.9)	(95.4)
Production	(17,764)	—	(17,764)	(604.1)	—	(604.1)
December 31, 2011	86,870	39,572	126,442	5,766.3	2,856.5	8,622.9

TOTAL	OIL EQUIVALENT Proved (Mboe)	OIL EQUIVALENT Probable (Mboe)	OIL EQUIVALENT Proved Plus Probable (Mboe)
December 31, 2010	140,189.5	88,835.4	229,025.0
Extensions	21,123.1	14,909.7	36,032.8
Improved Recovery	3,194.5	3,410.0	6,604.5
Technical Revisions	3,736.3	(15,291.7)	(11,555.4)
Discoveries	51.3	16.9	68.2
Acquisitions	8,107.0	4,761.7	12,868.7
Dispositions	(587.9)	(865.8)	(1,453.7)
Economic Factors	(953.3)	(163.6)	(1,116.9)
Production	(18,298.3)	—	(18,298.3)
December 31, 2011	156,562.2	95,612.5	252,174.8

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

Our operating budget typically allocates approximately two-thirds of our expected funds from operations to capital expenditures related to exploration and development activities. We allocate development capital to our assets in an efficient and disciplined process. We reduce risk by technically assessing the results of each of our development programs before committing additional capital. This disciplined approach to investing in development means that in most cases it will take longer than two years to develop our proved undeveloped and probable undeveloped reserves. We plan to develop the majority of our proved undeveloped reserves and probable undeveloped reserves over the next six years.

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

<u>Proved Undeveloped Reserves</u>

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

	Light and Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		NGLs Gross (Mbbl)		Natural Gas Gross (MMcf)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior	6,909.2	14,730.0	48,554.8	154,458.8	925.8	2,383.4	25,863	75,326
2009	1,874.4	8,002.4	18,084.9	49,363.0	106.1	312.9	3,123	9,331
2010	4,412.8	10,771.4	17,548.8	54,617.6	156.4	430.4	5,353	13,717
2011	6,838.6	18,999.4	9,725.6	53,998.0	3,594.3	3,811.3	17,061	28,112

Sproule assigned reserves to a total of 827 well locations to the proved undeveloped reserve category, of which 576 are located on our Canadian heavy oil properties. With respect to the heavy oil locations, 551 are primary locations which are scheduled to be drilled over the next twelve years and 25 are thermal locations at Seal which are scheduled to be drilled over the next four years. Sixty-four (64) of the proved undeveloped locations are located on our Canadian light oil and natural gas properties and are scheduled to be drilled over the next four years. The remaining 187 proved undeveloped locations are in the United States within Divide County, North Dakota and are scheduled to be drilled over the next five years. Each of the 827 locations with a proved undeveloped reserves assignment has a probable undeveloped reserves assignment too.

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

Probable Undeveloped Reserves

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

	Light and Medium Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		NGLs Gross (Mbbl)		Natural Gas Gross (MMcf)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
Prior	6,915.0	9,683.8	30,218.0	86,073.7	1,260.8	1,950.3	25,093	50,948
2009	3,457.1	7,518.2	19,426.4	31,494.5	135.4	368.2	4,444	11,210
2010	9,459.4	14,845.8	18,202.5	46,859.2	99.7	325.0	8,236	17,212
2011	5,269.5	11,435.4	12,971.9	51,344.2	1,912.1	2,116.1	8,666	16,794

In addition to those locations with proved undeveloped reserves, Sproule assigned reserves to a total of 265 well locations with probable undeveloped reserves only. None of these 265 locations have any proved undeveloped reserves assigned to them. Of these locations with probable undeveloped reserves only, 102 are located on our Canadian heavy oil properties. With respect to the heavy oil locations, 71 are primary locations which are scheduled to be drilled over the next eight years and 31 are thermal locations at Seal which are scheduled to be drilled over the next seven years. One hundred and twenty-four (124) of the probable undeveloped locations are located on our Canadian light oil and natural gas properties and are scheduled to be drilled over the next five years. The remaining 39 probable undeveloped locations are in the United States within Divide County, North Dakota and are scheduled to be drilled over the next two years. The table entitled "Probable Undeveloped Reserves" shows the probable undeveloped reserves for all of our locations, including the 827 locations with both a proved and probable undeveloped assignment, and those 265 locations with a probable undeveloped assignment only.

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

Significant Factors or Uncertainties

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

Future Development Costs

The following table sets forth development costs deducted in the estimation of the future net revenue attributable to the reserve categories noted below (using forecast prices and costs).

	CANADA		UNITED STATES		TOTAL	
($000s)	**Proved Reserves**	**Proved plus Probable Reserves**	**Proved Reserves**	**Proved plus Probable Reserves**	**Proved Reserves**	**Proved plus Probable Reserves**
2012	208,687	248,672	11,187	38,574	219,874	287,245
2013	223,025	285,339	42,670	67,456	265,695	352,796
2014	126,071	199,984	89,200	89,200	215,271	289,184
2015	61,125	144,985	93,202	93,202	154,327	238,187
2016	41,360	85,496	86,483	86,483	127,843	171,979
Remaining	112,273	134,167	—	—	112,273	134,167
Total (undiscounted)	772,540	1,098,643	322,743	374,915	1,095,283	1,473,558

We expect to fund the development costs of our reserves through a combination of internally generated funds from operations, debt and equity financings. Our operating budget typically allocates approximately two-thirds of our expected funds from operations to exploration and development activities.

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

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

Contingent Resource

We commissioned Sproule to conduct an assessment of contingent resource effective December 31, 2011on three of our oil resource plays: the Bluesky in the Seal area of Alberta, the Bakken/Three Forks in North Dakota and the Viking in the Redwater area of Alberta and the Kerrobert/Whiteside areas of Saskatchewan. We also commissioned McDaniel & Associates Consultants Ltd. ("**McDaniel**") to conduct an assessment of contingent resource effective December 31, 2011on certain heavy oil properties in Northeast Alberta.

Contingent resource represents the quantity of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets.

For the total of these four plays, Sproule and McDaniel's estimate of contingent resource ranges from 560 million barrels of oil and bitumen in the "low estimate" (C1) to 1.2 billion barrels of oil and bitumen in the "high estimate" (C3), with a "best estimate" (C2) of 783 million barrels of oil and bitumen. Contingent resources are in addition to currently booked reserves.

The tables below summarize Sproule's estimate of gross reserves and Sproule and McDaniel's estimates of contingent resource for the four plays by geographic area and the net present value before tax of the future net revenue attributable to the contingent resource using forecast prices and costs.

SUMMARY OF CONTINGENT RESOURCES(1)
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS(2)

	Summary of Contingent Resources(1) As of December 31, 2011 Forecast Prices and Costs(2)			
		Contingent Resources (gross)(5) As at Dec. 31, 2011		
(millions of barrels of oil equivalent and bitumen)(3)	Proved plus Probable Gross Reserves(4) As at Dec. 31, 2011	Low(6)	Best(7)	High(8)
Bluesky — Seal, Alberta	92.9	438.8	531.0	776.9
Mannville Group — Northeast Alberta	4.0	69.6	130.1	201.8
Bakken/Three Forks — North Dakota, USA	32.4	47.3	110.5	204.9
Viking — Redwater, Alberta	3.6	4.2	9.3	18.0
Viking — Kerrobert/Whiteside, Saskatchewan	4.2	0.6	1.9	10.1
Total	137.1	560.4	782.9	1,211.7

SUMMARY OF NET PRESENT VALUES OF
FUTURE NET REVENUES FROM CONTINGENT RESOURCES
AS OF DECEMBER 31, 2011
FORECAST PRICES AND COSTS(2)

	Summary of Net Present Values of Future Net Revenues from Contingent Resources As of December 31, 2011 Forecast Prices and Costs(2)			
	Before income taxes discounted at (%/year)(9)			
	0%	**5%**	**8%**	**10%**
	($ millions)			
Low estimate (C1)(6)				
Bluesky — Seal, Alberta	13,596.8	6,021.3	3,855.0	2,905.8
Mannville Group — Northeast Alberta	1,365.9	640.3	430.0	333.6
Bakken/Three Forks — North Dakota, USA	1,150.9	370.5	189.3	119.8
Viking — Redwater, Alberta	26.6	(0.1)	(9.1)	(13.2)
Viking — Kerrobert/Whiteside, Saskatchewan	(26.2)	(19.7)	(16.7)	(15.0)
Total	16,113.9	7,012.2	4,448.5	3,331.0
Best estimate (C2)(7)				
Bluesky — Seal, Alberta	17,810.2	7,757.3	4,927.1	3,697.2
Mannville Group — Northeast Alberta	3,365.4	1,348.7	856.8	648.8
Bakken/Three Forks — North Dakota, USA	5,650.3	1,821.3	1,014.6	708.6
Viking — Redwater, Alberta	421.5	260.5	200.0	169.1
Viking — Kerrobert/Whiteside, Saskatchewan	31.3	16.3	10.7	7.9
Total	27,278.8	11,240.1	7,009.2	5,231.6
High estimate (C3)(8)				
Bluesky — Seal, Alberta	29,738.4	12,092.3	7,434.6	5,476.0
Mannville Group — Northeast Alberta	6,088.5	2,265.1	1,404.7	1,053.9
Bakken/Three Forks — North Dakota, USA	13,540.2	3,874.9	2,093.7	1,450.7
Viking — Redwater, Alberta	1,083.3	666.5	518.4	444.2
Viking — Kerrobert/Whiteside, Saskatchewan	464.9	264.4	191.4	155.4
Total	50,915.4	19,163.2	11,642.8	8,580.2

Notes:

(1) The contingent resource assessments were prepared in accordance with the definitions, standards and procedures contained in the COGE Handbook and NI 51-101. Contingent resource is defined in the COGE Handbook as those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets.

(2) The forecast cost and price assumptions utilized in the Sproule Report were also utilized by Sproule and McDaniel in preparing the contingent resource assessments. See "*Description of Our Business and Operations — Statement of Reserves Data and Other Oil and Natural Gas Information — Pricing Assumptions*".

(3) Under NI 51-101, naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. The majority of the contingent resource at Seal that will be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resource is classified as bitumen under NI 51-101.

(4) Proved plus probable gross reserve volumes are based on the Sproule Report.

(5) Sproule and McDaniel prepared the estimates of contingent resource shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table. Gross means the company's working interest share in the contingent resource before deducting royalties.

(6) Low estimate (C1) is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources at the low end of the estimate range have the highest degree of certainty — a 90% confidence level — that the actual quantities recovered will be equal or exceed the estimate.

(7) Best estimate (C2) is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources that fall within the best estimate have a 50% confidence level that the actual quantities recovered will be equal or exceed the estimate.

(8) High estimate (C3) is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will meet or exceed the high estimate. Those resources at the high end of the estimate range have a lower degree of certainty — a 10% confidence level — that the actual quantities recovered will equal or exceed the estimate.

(9) The net present value of future net revenue attributable to the contingent resource does not necessarily represent the fair market value of the contingent resource. Estimated abandonment and reclamation costs have been included in the evaluation.

There is no certainty that it will be commercially viable to produce any portion of the contingent resource or that we will produce any portion of the volumes currently classified as contingent resource. The recovery and resource estimates provided herein are estimates. Actual contingent resource (and any volumes that may be reclassified as reserves) and future production from such contingent resource may be greater than or less than the estimates provided herein.

Other Oil and Gas Information

Oil and Natural Gas Properties

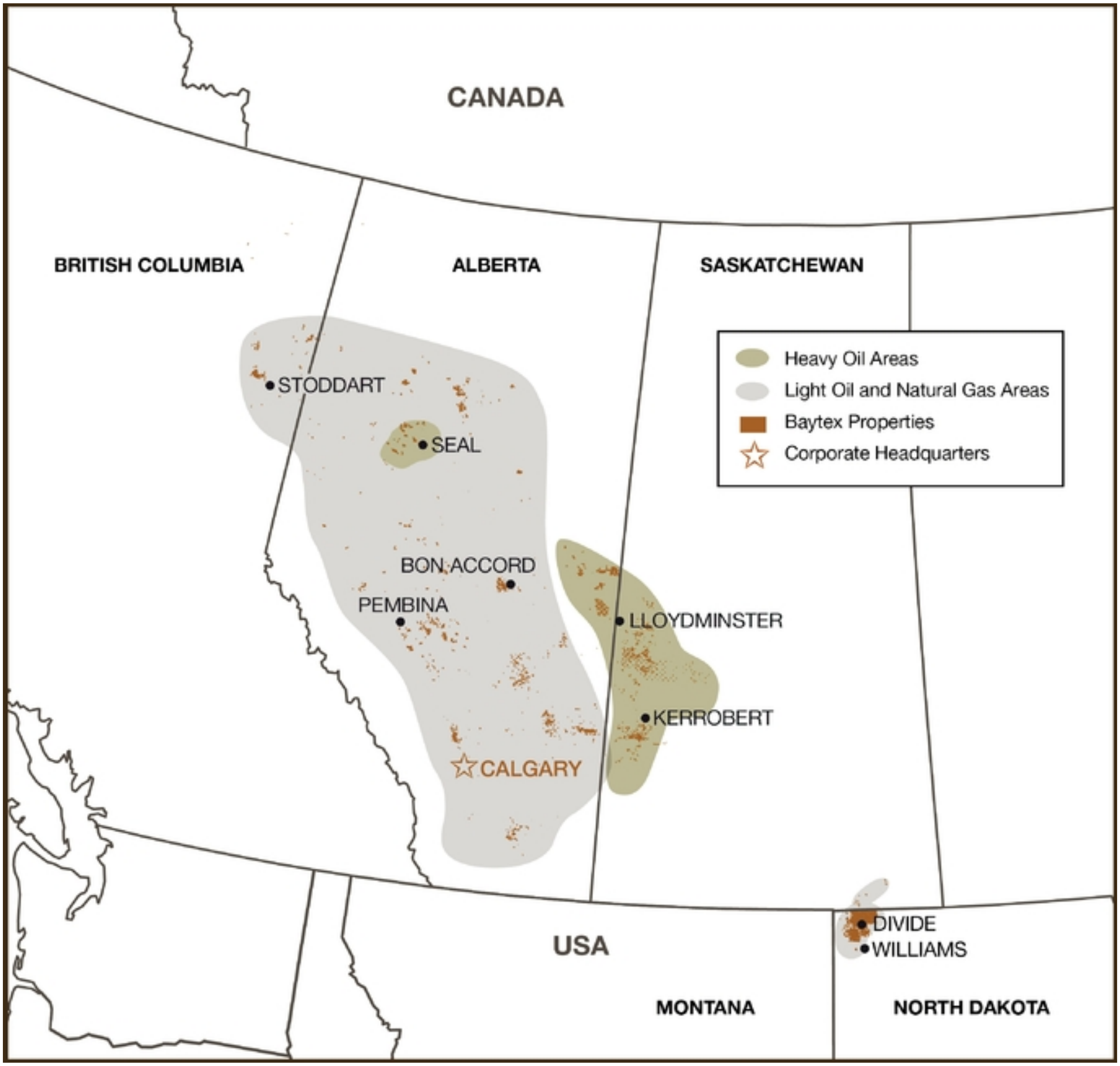
The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2011. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2011. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2011, except where otherwise indicated.

Our crude oil and natural gas operations are organized into three business units: Alberta/B.C., Saskatchewan and United States. Each business unit has a portfolio of mineral leases, operated and non-operated properties and development prospects. Within these business units, Baytex has established a total of nine geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach is intended to result in thorough identification and evaluation of exploration, development and acquisition investment opportunities and cost-efficient execution of those opportunities.

Baytex invested more than $100 million in undeveloped land over the past four years targeting light oil resource plays. These plays include the Bakken/Three Forks in the Williston Basin of North Dakota and southeast Saskatchewan and the Viking in southwestern Saskatchewan and eastern Alberta. These light oil resource plays provide the opportunity for long term light oil production and reserve growth to complement our heavy oil growth projects. These resource plays are described in more detail in the business unit descriptions below.

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

Baytex Energy Corp. — Principal Properties



Saskatchewan Business Unit

The Saskatchewan Business Unit accounts for more than 38% of current production and more than 32% of oil-equivalent reserves. The Saskatchewan Business Unit's heavy oil operations include cold primary and thermal (steam-assisted gravity drainage) production. In some cases, Baytex's heavy oil reservoirs are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 30 and 100 bbl/d of crude oil with gravities ranging from 10 to 18 degrees

API. Once produced, the oil is delivered to markets in both Canada and the United States on pipelines, tanker trucks or railways. Heavy crude is usually blended with light-hydrocarbon diluents (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2011, production in the Saskatchewan Business Unit averaged approximately 20,958 boe/d, which was comprised of 19,828 bbl/d of heavy oil, 154 bbl/d of light oil and 5,860 Mcf/d of natural gas. During 2011, Baytex drilled 93 (87.9 net) wells in the Saskatchewan Business Unit resulting in 84 (78.9 net) oil wells, four (4.0 net) stratigraphic test wells, four (4.0 net) service wells, and one (1.0 net) dry and abandoned well, for a success rate of 99%.

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

Baytex will endeavour to continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area within the Alberta / BC Business Unit and Baytex's historical area of emphasis around Lloydminster within the Saskatchewan Business Unit. Our net undeveloped lands in the Saskatchewan Business Unit totalled approximately 268,000 acres at year-end 2011.

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

Ardmore, Alberta: Acquired in 2002, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2011was approximately 652 bbl/d of heavy oil and 158 Mcf/d of natural gas (678 boe/d). One well was drilled in the area during 2011. Baytex anticipates drilling six wells in this area in 2012. At year-end 2011, Baytex had 34,000 net undeveloped acres in this area.

Carruthers, Saskatchewan: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. Thirteen new wells were drilled in 2011which, in combination with relatively low production declines due mostly to strong performance of the ongoing waterflood, led to a year-over-year production increase. The waterflood was expanded in 2009and 2010with further expansion planned for 2012. We plan to drill 5 horizontal wells and 6 vertical wells in the Carruthers area in 2012. Average production in 2011was approximately 2,444 bbl/d of heavy oil and 489 Mcf/d of natural gas (2,525 boe/d). At year-end 2011, Baytex had 10,600 net undeveloped acres in this area.

Celtic, Saskatchewan: This producing property was acquired by Baytex in 2005, in a transaction where Baytex purchased cold heavy oil production of 1,600 bbl/d and natural gas production of 900 Mcf/d. As a result of Baytex's well re-completion and drilling activities, production averaged 3,013 bbl/d of heavy oil and 538 Mcf/d of natural gas (3,103 boe/d) during 2011. The heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Baytex drilled seven oil wells in the area in 2011. Baytex plans to drill five new wells in this area in 2012. At year-end 2011, Baytex had 8,000 net undeveloped acres in this area.

<u>Cold Lake, Alberta:</u> This heavy oil property was initially acquired by Baytex in 2001. Production is primarily from the Colony, Upper McLaren, Rex and Sparky formations. Average oil production during 2011was approximately 270 bbl/d. Baytex plans to drill 15 new wells in this area in 2012. At year-end 2011, Baytex had 11,300 net undeveloped acres in this area.

<u>Kerrobert/Coleville, Saskatchewan:</u> Baytex acquired assets in the Kerrobert and Coleville areas of Saskatchewan in 2009. These properties provide numerous opportunities for cold infill drilling and steam-assisted gravity drainage ("**SAGD**") optimization. In addition, the Kerrobert area offers significant potential for light oil development in the Viking formation using horizontal wells with multi-stage hydraulic fractures.

In our Kerrobert SAGD project, we placed two new well pairs on production in the third quarter of 2011and the well pairs produced at a cumulative peak 30-day average rate of approximately 1,850 bbl/d with a steam-oil ratio of approximately 3.5 barrels of steam per barrel of oil. The total cost of the well pairs, including the cost of tie-ins, was $10.8 million. We believe that, through the remaining life of this project, we can drill up to nine additional well pairs with incremental costs of approximately $4.0 million per well pair. Average production from the Kerrobert area in 2011was approximately 3,350 bbl/d of heavy oil, 154 bbl/d of light oil, and 1,999 Mcf/d of natural gas (3,837 boe/d). Baytex drilled five oil wells and eight service wells in this area in 2011. Baytex plans to drill two primary oil wells in this area in 2012. At year-end 2011, Baytex had 38,600 net undeveloped acres in this area.

<u>Lindbergh, Alberta:</u> Lindbergh is a primarily non-operated heavy oil property that was purchased in 2007. Baytex has a 21.25% working interest in this property, which is operated by a senior Canadian producer. Average production in this area during 2011was approximately 673 bbl/d of heavy oil and 71 Mcf/d of natural gas (685 boe/d). Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. In 2011, four (0.9 net) wells were drilled in this area. At year-end 2011, Baytex had 800 net undeveloped acres in this area.

<u>Marsden/Epping/Macklin/Silverdale, Saskatchewan:</u> This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 degrees API. Initial per well production rates are typically 30 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2011was approximately 2,102 bbl/d of oil and 290 Mcf/d of natural gas (2,150 boe/d). Nine successful oil wells were drilled in this area in 2011. For 2012, a further five wells are planned. At year-end 2011, Baytex had 24,200 net undeveloped acres in this area.

<u>Tangleflags, Saskatchewan:</u> Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. In 2011, Baytex drilled eleven horizontal oil wells in the Lloydminster formation. We plan to drill approximately twelve horizontal oil wells in the area in 2012. Average production during 2011was approximately 1,763 bbl/d of heavy oil and 543 Mcf/d of natural gas (1,854 boe/d). At year-end 2011, Baytex had 7,700 net undeveloped acres in this area.

Alberta/B.C. Business Unit

The Alberta/B.C. Business Unit possesses an array of light oil, heavy oil and natural gas properties. In addition to Baytex's historical light oil, heavy oil and natural gas properties in northern and south-eastern Alberta, the geographic scope of our Alberta/B.C. Business Unit oil and gas operations has expanded to central Alberta and northeast British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Alberta/B.C. Business Unit produces light and heavy gravity crude oil, natural gas, and natural gas liquids from various fields in Alberta and British Columbia and accounts for approximately 58% of current production. During 2011, production from this business unit averaged 27,833 boe/d, which was comprised of 15,425 bbl/d of heavy oil, 5,282 bbl/d of light oil and NGL and 42.8 MMcf/d of natural gas. During 2011, the Alberta/B.C. Business Unit participated in the drilling of 71 (59.0 net) wells resulting in 61 (49.0 net) oil wells, one (1.0 net) natural gas well, seven (7.0 net) stratigraphic test wells, one (1.0 net) service well and one (1.0 net) dry and abandoned well for a success rate of 99%. Our net undeveloped lands in this business unit totalled approximately 474,000 acres at year-end 2011.

Listed below is a brief description of the principal properties within the Alberta/B.C. Business Unit:

<u>Bon Accord, Alberta:</u> Baytex acquired its initial position in this multi-zone property in 1997and has further expanded its presence through Crown land sales. Production is obtained from the Belly River, Viking and Mannville formations. During 2011, production for the area averaged approximately 905 bbl/d of light oil and 1,742 Mcf/d of natural gas (1,195 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. In the past two years, Baytex has begun to exploit the Viking sand utilizing multi-lateral horizontal drilling technology. In this area, Baytex drilled 11 (9.7 net) horizontal Viking oil wells in 2011. Baytex plans to drill approximately 11 multi-lateral horizontal Viking oil wells in this area in 2012. At year-end 2011, Baytex had 18,300 net undeveloped acres in this area.

<u>Darwin/Nina/Goodfish/Lafond, Alberta:</u> The properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at three Baytex-operated gas plants and one gas plant operated by a senior producer in which Baytex holds a 30% interest. Production during 2011averaged approximately 3,746 Mcf/d of natural gas (624 boe/d). At year-end 2011, Baytex had 27,300 net undeveloped acres in this area.

<u>Leahurst, Alberta:</u> Production averaged approximately 2,633 Mcf/d of natural gas and 13 bbl/d of NGL (452 boe/d) during 2011from this multi-zone, year-round access area. Natural gas production from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Baytex-operated. Baytex did not drill any wells in this area during 2011. At year-end 2011, Baytex had 7,300 net undeveloped acres in this area.

<u>Peace River, Alberta:</u> Baytex holds a total of 263 net sections of oil sands leases in the Peace River oil sands area, which includes the legacy Seal area and the Reno area which was acquired in February 2011. During 2011, production from the Peace River area was 15,425 bbl/d, which was comprised of 13,746 bbl/d from Seal and 1,679 bbl/d from Reno. In 2011, Baytex drilled 25 (25.0 net) cold horizontal production wells and seven (7.0 net) stratigraphic test wells at Seal and two (2.0 net) cold horizontal production wells at Reno. The purpose of the stratigraphic test wells is to improve delineation of our land base and guide development well trajectories. In 2012, Baytex plans to drill 25 cold horizontal wells and 14 stratigraphic test wells at Seal and 15 cold horizontal wells and four stratigraphic test wells at Reno. The Peace River area includes 152,500 net undeveloped acres, including 57,000 net undeveloped acres at Seal and 95,500 net undeveloped acres at Reno.

In certain parts of this Peace River land base, heavy oil can be produced using horizontal wells at initial production rates of 150 to 500 bbl/d per well, without employing more cost-intensive methods such as steam injection. Reservoir analysis of the Seal property has indicated that both waterflood and cyclic steam recovery methods have the potential to increase economic oil reserves beyond what is achievable with cold primary recovery.

Our first cyclic steam stimulation ("**CSS**") pilot project was carried out on an existing horizontal producer in the Harmon Valley area during 2008to validate our numerical reservoir simulation models of CSS. In 2010, we implemented a second cyclic steam project in the Cliffdale area, seven miles to the east of the first CSS pilot project. In 2011, a number of important milestones were achieved at our

Cliffdale CSS project. The third cycle of the original Cliffdale pilot well was completed, achieving a peak oil rate of 400 bopd with a cycle steam-oil ratio (SOR) below 1.8. In the first half of 2011, we drilled four additional CSS wells and commenced cold production to create voidage. In the second half of 2011, we commissioned our Cliffdale commercial steam injection and production facility and initiated steam injection into the wells which had been drilled earlier in the year. At year-end 2011, our reserves engineers assigned developed producing reserves to the Cliffdale CSS project for the first time. Finally, in late 2011we commenced drilling operations on the final five CSS wells of the first 10-well Cliffdale thermal module, setting intermediate casing before year-end and drilling the horizontal laterals in January 2012. Subsequent to the end of 2011, we finished first cycle injection operations and commenced flowback operations in two wells drilled earlier in 2011. Each of these wells accepted 40% more steam than our original CSS pilot well in its first cycle, and we observed peak oil rates of approximately 300 bbl/d per well, 20% higher than first cycle pilot well performance.

Baytex has applied for regulatory approval for a 15-well Cliffdale CSS project immediately adjacent to the 10-well Cliffdale module. Depending on approval timing, Baytex anticipates drilling five CSS wells in the new 15-well thermal module and commencing facility construction in the fourth quarter of 2012. Also in 2012, we plan to drill approximately five stratigraphic test wells to further delineate our Cliffdale area lands for future CSS development.

Pembina, Alberta: Baytex acquired its initial position in Pembina in 2007and further expanded its presence in the area through the acquisition of Burmis Energy Inc. in 2008. Production is primarily from the Nisku formation and to a lesser extent from Cretaceous and Jurassic age formations, including the Cardium, Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's production in this area is treated at a Baytex-operated oil battery with the remaining production treated at a third party-operated oil battery. Natural gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the producer-operated gas processing facilities and a minor working interest in one of the mid-stream gas processing facilities. During 2011, Pembina production averaged 2,633 bbl/d of light oil and NGL and 22,428 Mcf/d of natural gas (6,371 boe/d). Baytex participated in drilling 19 (8.5 net) wells in this area in 2011, resulting in 17 (6.5 net) oil wells, one (1.0 net) natural gas well, and one (1.0 net) dry and abandoned well. Pembina area drilling included five (5.0 net) operated and 12 (1.5 net) non-operated Cardium horizontal wells which were successfully drilled and completed with multi-stage fracture stimulations. Baytex plans to drill ten wells in this area in 2012. At year-end 2011, Baytex had 19,300 net undeveloped acres in this area.

In the fourth quarter of 2011, Baytex completed the construction of a 33 kilometre "wet" natural gas pipeline in the Pembina region. This 100% owned and operated infrastructure expansion project was required to alleviate capacity restrictions that had adversely impacted our O'Chiese area natural gas and NGL production in 2011.

Red Earth Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Production from this area during 2011averaged approximately 42 Mcf/d of natural gas and 522 bbl/d of light oil and NGL (529 boe/d). Baytex participated in two (1.8 net) successful oil wells in this area in 2011, and we plan to drill one well in the area in 2012. At year-end 2011, Baytex had 8,600 net undeveloped acres in this area.

Richdale/Sedalia, Alberta: Baytex acquired its initial position in this area in 2001and increased its presence through the acquisition of a private company in 2004. During 2011, production averaged approximately 3,845 Mcf/d of natural gas and 8 bbl/d of NGL (649 boe/d). This area has year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the natural gas produced from this area is processed at two Baytex-operated gas plants. At year-end 2011, Baytex had 28,000 net undeveloped acres in this area.

Stoddart, British Columbia: The Stoddart asset acquisition occurred in 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at two third party-operated gas plants. Production from this area during 2011averaged approximately 4,498 Mcf/d of natural gas and 713 bbl/d of oil and NGL (1,463 boe/d). Baytex did not drill any wells in this area in 2011. At year-end 2011, Baytex had 23,700 net undeveloped acres in this area.

Turin, Alberta: This multi-zone, year-round access property was acquired in 2004. Production during 2011averaged approximately 345 bbl/d of oil and NGL and 856 Mcf/d of natural gas (488 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Baytex-operated batteries and natural gas is processed at two third party-operated gas plants. Baytex did not drill any wells in this area in 2011. At year-end 2011, Baytex had 5,700 net undeveloped acres in this area.

United States Business Unit

Baytex acquired significant land positions in the Powder River and Williston basins in 2007and 2008. During 2011, we focused our activities on the light oil resource play located in the Divide and Williams Counties of North Dakota. Production is primarily from horizontal wells using multi-stage hydraulic fracturing in the Bakken and Three Forks formations. We have invested in approximately 277,900 (116,000 net) acres of land, of which 216,900 (91,200 net) acres were undeveloped at year-end 2011. Baytex now owns approximately 61,000 (24,800 net) developed acres. In 2011, Baytex participated in the drilling of 34 (10.4 net) Bakken/Three Forks oil wells with a success rate of 100%. In 2012, Baytex plans to drill approximately 24 (9.6 net) horizontal wells. Ultimately, assuming development of only one stratigraphic elevation, the project has the potential to include 100 to 300 wells with average initial production rates expected to be approximately 420 boe/d per well and average recoveries expected to be approximately 420 Mboe per well, based on drilling two-mile (or 1,280-acre spacing unit) wells. Despite some wells not yet having been completed due to constraints in oilfield services, net production from the United States properties averaged 1,341 boe/d in 2011, as compared to 742 boe/d in 2010, and grew steadily through the year, reaching over 1,800 boe/d in December 2011.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2011.

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Saskatchewan Business Unit				
Ardmore	—	652	158	678
Carruthers	—	2,444	489	2,525
Celtic	—	3,013	538	3,103
Cold Lake	—	270	—	270
Forest Bank	—	760	57	769
Golden Lake	—	1,061	558	1,154
Greenstreet	—	132	—	132
Hoosier	—	439	—	439
Kerrobert/Coleville	154	3,350	1,999	3,837
Lindbergh	—	673	71	685
Maidstone	—	880	—	880
Marsden/Epping/Macklin/Silverdale	—	2,102	290	2,150
Neilburg	—	677	—	677
Poundmaker/Freemont	—	1,282	328	1,337
Sugden	—	193	—	193
Tangleflags	—	1,763	543	1,854
Remaining properties	—	136	829	275
Total Saskatchewan Business Unit	154	19,827	5,860	20,958
Alberta/B.C. Business Unit				
Bon Accord	905	—	1,742	1,195
Darwin/Nina/Goodfish/Lafond	—	—	3,746	624
Leahurst	13	—	2,633	452
Pembina	2,633	—	22,428	6,371
Red Earth	522	—	42	529
Seal/Reno	—	15,425	—	15,425
Richdale/Sedalia	8	—	3,845	649
Stoddart	713	—	4,498	1,463
Turin	345	—	856	488
Remaining Properties	144	—	2,967	637
Total Alberta/B.C. Business Unit	5,283	15,425	42,757	27,833
United States Business Unit				
Williston Basin	1,289	—	52	1,298
Remaining properties	43	—	—	43
Total United States Business Unit	1,332	—	52	1,341
Grand Total	6,769	35,252	48,669	50,132

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2011:

	Canada	United States ($000s)	Total
Property acquisition costs[(1)]			
Proved properties	$162,725	$502	$163,227
Unproved properties	30,288	2,655	32,943
Property disposition	(47,396)	—	(47,396)
Total Property acquisition costs, net	145,617	3,157	148,774
Development Costs[(2)]	284,711	74,033	358,744
Exploration Costs[(3)]	5,672	3,432	9,104
Total	$436,000	$80,622	$516,622

Notes:

(1) Property acquisition costs include the acquisition of assets in the Reno area of northwest Alberta and the Lloydminster area of west central Saskatchewan.

(2) Development and facilities expenditures.

(3) Cost of geological and geophysical capital expenditures and drilling costs for 2010exploratory wells drilled.

Oil and Gas Wells

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2011.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	776	502.0	975	542.6	520	382.4	435	336.1
British Columbia	47	46.6	33	32.2	38	34.8	11	10.5
Saskatchewan	1,249	1,134.9	1,237	1,146.9	43	38.5	126	113.6
North Dakota	109	32.4	—	—	—	—	—	—
Wyoming	5	2.6	—	—	—	—	—	—
Total	2,186	1,718.5	2,245	1,721.7	601	455.7	572	460.2

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2011.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	665,042	525,633
British Columbia	56,999	30,453
Saskatchewan	205,540	179,642
Total Canada	927,581	735,728
United States		
New Mexico	14,312	14,312
North Dakota	216,870	91,160
Utah	180	89
Wyoming	37,364	25,159
Total United States	268,726	130,720
Grand Total	1,196,307	866,448

We estimate the value of our net undeveloped land holdings at December 31, 2011to be approximately $454 million, as compared to $391 million at December 31, 2010. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

We expect that rights to explore, develop and exploit approximately 82,512 net acres of our undeveloped land holdings may expire on or before December 31, 2012. There are no material drilling commitments associated with the land holdings expiring by December 31, 2012.

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, 2011.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	1	1.0	178	137.3	179	138.3
Natural Gas			1	1.0	1	1.0
Evaluation	6	6.0	5	5.0	11	11.0
Service			5	5.0	5	5.0
Dry	1	1.0	1	1.0	2	2.0
Total	8	8.0	190	149.3	198	157.3

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2011, see Note 23 to our annual audited financial statements for the year ended December 31, 2011.

Tax Horizon

Based on the current tax regime and Baytex's available tax pools and anticipated level of funds from operations and capital spending, Baytex does not expect to pay material amounts of cash income taxes (other than Saskatchewan Resource Surcharge) prior to 2013. This estimate is highly sensitive to assumptions regarding commodity prices, production, funds from operations and capital expenditure levels. As at December 31, 2011, Baytex's total Canadian tax pools were estimated to be $1.6 billion, including $266 million for tangibles, $607 million for intangibles and $712 million in non-capital loss carryforwards. In addition, as at December 31, 2011, Baytex's total United States tax pools were estimated to be $293 million, including $93 million for tangibles, $109 million for intangibles and $91 million in non-capital loss carryforwards.

Additional Information Concerning Abandonment and Reclamation Costs

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

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($ millions)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($ millions)
Total liability as at December 31, 2011	315.86	37.21
Anticipated to be paid in 2012	1.35	1.30
Anticipated to be paid in 2013	1.19	1.06
Anticipated to be paid in 2014	3.02	2.50

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

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

The number of net wells for which we estimated we will incur reclamation and abandonment costs is 5,214 wells. This estimate includes all producing wells, all non-producing wells, all standing cased wells and all suspended wells. The number of net wells for which Sproule estimated we will incur reclamation and abandonment costs is 746 wells which are all the proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2011. Abandonment and reclamation costs have been estimated over a 52-year period. Facility reclamation costs are scheduled to be incurred two years following the end of the reserve life of its associated producing area. Only well abandonment costs, net of downhole salvage value were deducted by Sproule in estimating future net revenue in the Sproule Report. The additional liability associated with our existing wells, pipelines and facility reclamation costs, net of salvage, which was estimated to be $315.86 million ($37.2 million discounted at 10 percent), was not deducted in estimating future net revenue.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2012, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Description of Our Business and Operations — Statement of Reserves Data and Other Oil and Gas Information — Disclosure of Reserves Data and Oil and Natural Gas Information*".

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas liquids (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA					
Total Proved	3,659	36,845	1,568	40,788	48,869
Total Proved plus Probable	4,227	40,279	1,740	44,296	53,628
UNITED STATES					
Total Proved	2,002	—	—	53	2,011
Total Proved plus Probable	2,646	—	—	54	2,655
TOTAL					
Total Proved	5,661	36,845	1,568	40,841	50,880
Total Proved plus Probable	6,873	40,279	1,740	44,350	56,283

The only property that accounts for 20% or more of the estimated 2012 production volumes is Seal, Alberta. Estimated 2012 production volumes for Seal are 14,614 boe/d on a total proved basis and 15,907 boe/d on a total proved plus probable basis. Note: these production volumes do not include production from the adjacent Reno area.

Production History

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

	Three Months Ended				Year Ended
	Dec. 31, 2011	Sept 30, 2011	June 30, 2011	Mar. 31, 2011	Dec. 31, 2011
Average Daily Production(1)					
Light Oil and NGL (bbl/d)(2)	7,232	7,170	6,055	6,606	6,769
Heavy Oil (bbl/d)	38,006	37,280	33,839	31,792	35,252
Natural Gas (Mcf/d)	46,891	49,047	47,755	51,022	48,668
Total (boe/d)	53,054	52,625	47,853	46,902	50,132
Average Net Production Prices Received					
Light Oil and NGL($/bbl)(2)	85.09	80.48	89.11	75.68	82.49
Heavy Oil ($/bbl)	70.85	59.92	71.02	59.89	65.53
Natural Gas ($/Mcf)	3.91	4.20	4.36	4.19	4.17
Total ($/boe)	65.81	57.31	65.84	55.86	61.26
Royalties Paid					
Light Oil and NGL($/bbl)(2)	16.36	17.56	18.90	17.35	17.48
Heavy Oil ($/bbl)	13.82	10.51	12.89	12.58	12.44
Natural Gas ($/Mcf)	0.54	0.75	0.28	0.40	0.49
Total ($/boe)	12.61	10.54	11.78	11.42	11.59
Operating Expenses(3)(4)					
Light Oil and NGL($/bbl)(2)	12.81	13.60	10.20	8.69	11.45
Heavy Oil ($/bbl)	10.97	11.08	11.31	11.03	11.09
Natural Gas ($/Mcf)	2.01	2.07	2.27	2.21	2.14
Total ($/boe)	11.38	11.64	11.56	11.11	11.43
Transportation Expenses					
Light Oil and NGL($/bbl)(2)	0.45	0.61	0.59	0.32	0.50
Heavy Oil ($/bbl)	4.76	4.51	5.04	3.97	4.58
Natural Gas ($/Mcf)	0.16	0.18	0.17	0.17	0.17
Total ($/boe)	3.61	3.44	3.81	2.94	3.46
Netback Received(5)					
Light Oil and NGL($/bbl)(2)	55.47	48.71	59.43	49.32	53.06
Heavy Oil ($/bbl)	41.30	33.82	41.77	32.31	37.42
Natural Gas ($/Mcf)	1.20	1.20	1.64	1.40	1.37
Total ($/boe)	38.21	31.69	38.69	30.39	34.78
Financial Instruments gain ($/boe)(6)	(0.27)	1.30	(1.93)	0.37	(0.10)
Netback Received after hedging ($/boe)	37.94	32.99	36.76	30.76	34.68

Notes:

(1) Before deduction of royalties.

(2) Our NGL volumes are not material, and have been grouped with light oil for reporting purposes.

(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.

(4) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.

(5) Netback is calculated by subtracting royalties, operating expenses, transportation expenses and losses/gains on commodity and foreign exchange contracts from revenues.

(6) Financial instruments reflect only realized derivative gains (losses).

Marketing Arrangements

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

Natural Gas

North American natural gas prices in 2011 were marginally lower than in 2010, reflecting continuing pressure on prices due to a number of factors. The NYMEX Henry Hub price averaged US$4.04/MMbtu in 2011, as compared to US$4.39/MMbtu in 2010. The most significant factor affecting prices was the continued growth in U.S. natural gas production from shale plays, enabled by improvements in horizontal drilling and multi-stage fracturing technology. In spite of increased natural gas demand from winter and summer weather, record U.S. natural gas supplies weighed on the market and resulted in high natural gas storage levels relative to historic norms. As a result, natural gas prices gradually declined over 2011 from a high of US$4.847/MMbtu on June 8 to a low of US$2.989/MMbtu on December 30.

For 2011, Baytex's average physical natural gas sales price (inclusive of physical forward sales contracts) was $4.17/mcf, as compared to $4.32/mcf in 2010.

Oil and NGL

Oil prices in 2011 were volatile, but generally higher than in 2010. During 2011, daily NYMEX WTI prices ranged from a low of US$76.29/bbl (on October 10) and a high of US$113.93/bbl (on April 29) and ended the year at US$98.83/bbl. The average WTI price during 2011 was US$95.12/bbl, as compared to an average of US$79.53/bbl in 2010. Over the course of 2011, the benchmark WTI price was supported by an improving global outlook, together with strong oil demand growth from China and other emerging market countries. In spite of a mid-year oil price set-back related to European economic uncertainty, oil prices staged a sustained fourth-quarter rally, driven by continued global oil demand growth.

For 2011, Baytex's light oil and NGL prices averaged $82.49/bbl, while heavy oil sales prices averaged $65.53/bbl (net of physical forward sales gains of $0.17/bbl). In contrast, for 2010 Baytex averaged $65.90/bbl for light oil and NGL and $59.40/bbl for heavy oil sales (net of physical forward sales losses of $0.68/bbl). Baytex's total oil and NGL price in 2011 was $68.26/bbl (net), compared with $60.61/bbl (net) in 2010.

Environmental Policies

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

DIRECTORS AND OFFICERS

The following table sets forth the name, municipality of residence, age as at December 31, 2011, position held with Baytex and principal occupation of each of the directors and officers of Baytex.

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
John A. Brussa(2)(3)(4)(6) Calgary, Alberta	54	Director	Partner with Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	56	Director and Executive Chairman	Executive Chairman of Baytex
Edward Chwyl(2)(3)(4) Victoria, B.C.	68	Director	Independent Businessman
Naveen Dargan(1)(2)(4) Calgary, Alberta	54	Director	Independent Businessman
R.E.T. (Rusty) Goepel(1) Vancouver, B.C.	69	Director	Senior Vice President of Raymond James Ltd.
Anthony W. Marino Calgary, Alberta	51	Director, President and Chief Executive Officer	President and Chief Executive Officer of Baytex
Gregory K. Melchin(1) Calgary, Alberta	58	Director	Independent Businessman
Dale O. Shwed(3) Calgary, Alberta	53	Director	President and Chief Executive Officer of Crew Energy Inc.
Daniel G. Anderson Denver, Colorado	49	Vice President, U.S. Business Unit	President of Baytex USA
Kendall D. Arthur Calgary, Alberta	31	Vice President, Saskatchewan Business Unit	Vice President, Saskatchewan Business Unit of Baytex
W. Derek Aylesworth Calgary, Alberta	49	Chief Financial Officer	Chief Financial Officer of Baytex
Stephen Brownridge Calgary, Alberta	52	Vice President, Exploration	Vice President, Exploration of Baytex
Geoffrey J. Darcy Calgary, Alberta	49	Vice President, Marketing	Vice President, Marketing of Baytex
Murray J. Desrosiers Calgary, Alberta	42	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary of Baytex
Brian G. Ector Calgary, Alberta	43	Vice President, Investor Relations	Vice President, Investor Relations
Michael S. Kaluza Calgary, Alberta	52	Vice President, Corporate Development and Planning	Vice President, Corporate Development and Planning of Baytex
Brett J. McDonald Calgary, Alberta	49	Vice President, Land	Vice President, Land of Baytex
Timothy R. Morris Denver, Colorado	55	Vice President, US Business Development	Vice President of Baytex USA

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
Marty L. Proctor Calgary, Alberta	51	Chief Operating Officer	Chief Operating Officer of Baytex
Richard P. Ramsay Calgary, Alberta	48	Vice President, Alberta/B.C. Business Unit	Vice President, Alberta/B.C. Business Unit of Baytex

Notes:

(1) Member of our Audit Committee.

(2) Member of our Compensation Committee.

(3) Member of our Reserves Committee.

(4) Member of our Nominating and Governance Committee.

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

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

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

John A. Brussa became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since October 8, 1997. He is a partner at Burnet, Duckworth & Palmer LLP and focuses on tax law. He was admitted to the Alberta bar in 1982. Mr. Brussa is a director of several public companies including Chinook Energy Inc., Crew Energy Inc., Just Energy Group Inc., Penn West Petroleum Ltd., Progress Energy Resources Corp. and Storm Resources Ltd. He holds a Bachelor of Laws degree from the University of Windsor where he was a gold medalist and a Bachelor of Arts, History and Economics degree also from the University of Windsor.

Raymond T. Chan was appointed Executive Chairman of Baytex on December 31, 2010 and has held the same position with Baytex Energy since January 1, 2009. He originally joined Baytex Energy in October 1998 and has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to August 2003); President and Chief Executive Officer (September 2003 to November 2007); and Chief Executive Officer (November 2007 to December 2008). Mr. Chan has been a director of Baytex Energy since October 1998. Mr. Chan has held senior executive positions in the Canadian oil and gas industry since 1982, including chief financial officer titles at Tarragon Oil and Gas Limited, American Eagle Petroleums Ltd. and Gane Energy Corporation. Mr. Chan holds a Bachelor of Commerce degree and is a chartered accountant.

Edward Chwyl became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since May 27, 2003. Mr. Chwyl was Chairman of the Board of Directors of Baytex Energy from September 2003 to December 2008. He was appointed Lead Independent Director of Baytex on January 11, 2011 and has held the same position with Baytex Energy since February 17, 2009. He holds a Bachelor of Science degree in Chemical Engineering and a Master of Science degree in Petroleum Engineering. He is a retired businessman with over 35 years experience in the oil and gas industry in North America, most notably as President and Chief Executive Officer of Tarragon Oil and Gas Limited from 1989 to 1998. Prior thereto, he held various technical and executive positions within the oil and gas industry in Canada and the United States.

Naveen Dargan became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since September 1, 2003. He has been an independent businessman since June 2003. Prior thereto, he worked for over 20 years in the investment banking business, finishing his investment banking career as Senior Managing Director and Head of Energy Investment Banking at Raymond James Ltd. Mr Dargan is a director of CCS Corporation. He holds a Bachelor of Arts (Honours) degree in Mathematics and Economics, a Master of Business Administration degree and a Chartered Business Valuator designation.

R.E.T. (Rusty) Goepel became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since May 11, 2005. He is currently Senior Vice President for Raymond James Ltd. He commenced his career in investment banking in 1968 and was President and co-founder of Goepel Shields & Partners, which later became Goepel McDermid Ltd. and was acquired by Raymond James Ltd. in 2001. Mr. Goepel holds a Bachelor of Commerce (Honours) degree.

Anthony W. Marino was appointed President, Chief Executive Officer and director of Baytex on October 22, 2010 and has held the same position with Baytex Energy since January 1, 2009. Mr. Marino joined Baytex Energy in November 2004 as Chief Operating Officer and was promoted to President and Chief Operating Officer in November 2007. Prior to joining Baytex Energy, Mr. Marino was President and Chief Executive Officer of Dominion Exploration Canada Ltd. (a subsidiary of Dominion Resources Inc.). Mr. Marino's earlier experience included managing the Jonah/Pinedale asset area for AEC Oil and Gas (USA) Inc., operations and business development management for Santa Fe Snyder Corp. and several technical and management positions with Atlantic Richfield Company. He is a registered professional engineer and a Chartered Financial Analyst, and has over 30 years of experience in the North American oil and gas industry. Mr. Marino has a Bachelor of Science degree with Highest Distinction in Petroleum Engineering from the University of Kansas and a Masters of Business Administration degree from California State University at Bakersfield. Mr. Marino is a member of the Board of Directors of Enterprise Saskatchewan, the central economic development agency of the Government of Saskatchewan, and was previously a member of both the Board of Governors for the Canadian Association of Petroleum Producers and the Board of Directors for the Independent Petroleum Association of Mountain States in the United States.

Gregory K. Melchin became a director of Baytex on December 31, 2010 and has been a director of Baytex Energy since May 20, 2008. He is currently the Chairperson of Enmax Corporation, a municipally-owned utility. He was a member of the Legislative Assembly of Alberta from 1997 to March 2008. Among his various assignments with the Government of Alberta, he was Minister of Energy, Minister of Seniors and Community Supports and Minister of Revenue. Prior to being elected to the Legislative Assembly of Alberta, he served in various management positions for 20 years in the Calgary business community. He holds a Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. He has also completed the Directors Education Program with the Institute of Corporate Directors.

Dale O. Shwed became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since June 3, 1993. He has held the position of President and Chief Executive Officer of Crew Energy Inc., a public oil and gas company, since September 2003. Prior thereto, he was President and Chief Executive Officer of Baytex Energy from 1993 to August 2003. Mr. Shwed holds a Bachelor of Science degree specializing in Geology.

Daniel G. Anderson was appointed Vice President, U.S. Business Unit on September 14, 2011. In this role he is also President of Baytex's wholly-owned subsidiary, Baytex Energy USA Ltd., which is based in Denver, Colorado. Mr. Anderson has over 25 years of experience in the upstream and mid-stream energy industry in the U.S. He was formerly Vice President of Rocky Mountain and Mid-Continent Production with Berry Petroleum Company. Mr. Anderson previously held a variety of technical and management positions with Williams, Barrett Resources, Santa Fe Snyder and Conoco. His work has involved both operating and business development activities in the Williston Basin, U.S. Rockies, Mid-Continent and Gulf Coast regions. Mr. Anderson received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines and is a practicing member of the Society of Petroleum Engineers (SPE).

Kendall D. Arthur was appointed Vice President, Saskatchewan Business Unit of Baytex on January 4, 2012. Mr. Arthur has over 10 years experience in the Canadian oil and gas industry. He joined Baytex Energy in 2006 as a Production Engineer in the Heavy Oil Business Unit. Prior to joining Baytex, he held various technical production, completions and operations roles with Husky Energy. Mr. Arthur received a Bachelor of Science degree in Mechanical Engineering from the University of Saskatchewan and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

W. Derek Aylesworth was appointed Chief Financial Officer of Baytex on October 22, 2010 and has held the same position with Baytex Energy since November 2005. He is responsible for Baytex's capital markets, financial reporting and compliance, financial risk management, tax and treasury functions. Prior to joining Baytex Energy, Mr. Aylesworth held the position of Commercial Manager of the Ecuador Region business unit at EnCana Corporation. Prior thereto, he was the Division Vice President for the International New Ventures Exploration business unit of the same company. Mr. Aylesworth has over 20 years of experience in the Canadian oil and gas industry. Mr. Aylesworth holds a Bachelor of Commerce degree and is a chartered accountant with expertise in taxation and has experience as a tax advisor in both the oil and gas industry and public practice in Calgary.

Stephen Brownridge was appointed Vice President, Exploration of Baytex on December 31, 2010 and has held the same position with Baytex Energy since January 5, 2010. Mr. Brownridge has over 20 years experience in the Canadian oil and gas industry. He joined Baytex Energy in 1997 and held the position of Manager of the Heavy Oil Business Unit from September 2003 to December 2006 and Vice President, Heavy Oil from December 2006 to January 2010. Prior to joining Baytex Energy, Mr. Brownridge held technical positions with Koch Exploration Canada Corporation and Rigel Oil and Gas Ltd. Mr. Brownridge holds a Bachelor of Science degree with Honours in Geology from the University of Manitoba, and a Master of Science Degree in Geology obtained jointly from the University of Alberta and Louisiana State University.

Geoffrey J. Darcy was appointed Vice President, Marketing of Baytex on September 5, 2011. Prior to that, he was Director of North American Physical Crude Oil Trading for Barclays Bank. Mr. Darcy has over 25 years experience in marketing, trading and crude oil supply in both Canada and the U.S. He was formerly Vice President of North American Crude Oil Marketing with Nexen Inc., and worked in crude oil supply for United Refining Company and Petro-Canada earlier in his career. In his new role with Baytex, Mr. Darcy will lead our efforts to maximize the value of our products and to manage our risk exposures. Mr. Darcy has a Bachelor of Commerce degree with Honours in Economics with Distinction from Concordia University and a Master of Business Administration from the University of Calgary.

Murray J. Desrosiers was appointed Vice President, General Counsel and Corporate Secretary of Baytex on October 22, 2010 and has held the same positions with Baytex Energy since May 20, 2009. Mr. Desrosiers is a corporate lawyer with over 15 years of experience advising energy companies in the areas of corporate finance, mergers and acquisitions, corporate governance and securities compliance matters. He joined Baytex Energy in July 2008 and held the position of General Counsel from August 2008 to May 2009. Prior to joining Baytex Energy, he held senior legal positions with PrimeWest Energy Inc. (the operating company of PrimeWest Energy Trust), Shiningbank Energy Ltd. (the operating company of Shiningbank Energy Income Fund), Enbridge Inc. and Enbridge Management Services Inc. (the manager of Enbridge Income Fund). Mr. Desrosiers holds a Bachelor of Laws from the University of Alberta and a Bachelor of Commerce (Finance) from the University of Calgary and is a member of the Law Society of Alberta.

Brian G. Ector was appointed Vice President, Investor Relations of Baytex on June 20, 2011 and is responsible for all of Baytex's investor relations functions. He joined Baytex in November 2009 and held the position of Director of Investor Relations from November 2009 to June 2011. Prior to joining Baytex, Mr. Ector spent 15 years as a sell-side research analyst (the last seven years with Scotia Capital) covering both energy trusts and exploration and production corporations. Mr. Ector received a Bachelor of Commerce with a concentration in finance from the University of Calgary and received his CFA designation in 1996. He is a member of CIRI, NIRI, the CFA Institute and the Calgary CFA Society.

Michael S. Kaluza joined Baytex as Vice President, Planning on June 20, 2011 and was appointed Vice President, Corporate Development & Planning on February 1, 2012. He has over 25 years of experience in the North American and international oil and gas industry. Prior to joining Baytex, he was Chief Operating Officer of Delphi Energy Corp. Prior to that, Mr. Kaluza held a variety of technical and management positions with Dominion Exploration and Production Inc. and Phillips Petroleum Company. Mr. Kaluza brings strong operational, engineering and project evaluation skills which will be valuable in developing our long range growth plans. Mr. Kaluza received a Bachelor of Science degree with Honours in Petroleum Engineering from Montana Tech of The University of Montana.

Brett J. McDonald was appointed Vice President, Land of Baytex on December 31, 2010 and has held the same position with Baytex Energy since December 1, 2006. Mr. McDonald has over 25 years of experience in the Canadian oil and gas industry. He joined Baytex Energy in 2000 and held the position of General Manager of Land from September 2003 to December 2006. Prior to joining Baytex Energy, Mr. McDonald held senior land negotiating positions with Newport Petroleum Corporation, Stampeder Exploration Ltd. and Murphy Oil Company Ltd. Mr. McDonald is a member of the Canadian Association of Petroleum Landmen.

Timothy R. Morris was appointed Vice President, U.S. Business Development of Baytex on December 31, 2010 and has held the same position with Baytex Energy since November 12, 2007. He joined Baytex Energy in April 2007 as Managing Director, U.S. Business Development. Mr. Morris has over 30 years of experience in the United States oil and gas industry. Prior to joining Baytex Energy, he held senior management positions with Berco Resources, LLC, Santa Fe Snyder Corporation, Snyder Oil Corporation, Petroleum, Inc. and Sohio Petroleum Corp. He received a Bachelor of Science degree with an area of emphasis in Minerals Land Management from the University of Colorado and is a Certified Professional Landman. He is a member of the Independent Petroleum Association of Mountain States, Denver Association of Petroleum Landmen and the American Association of Professional Landmen.

Marty L. Proctor was appointed Chief Operating Officer of Baytex on December 31, 2010 and has held the same position with Baytex Energy since January 14, 2009. Mr. Proctor has over 25 years of experience in the Canadian and international oil and gas industries, with particular emphasis in heavy oil operations. Prior to joining Baytex Energy, he was Senior Vice President responsible for upstream operations for StatoilHydro Canada. Prior to that, Mr. Proctor was Senior Vice President of North American Oil Sands Corporation and Vice President of Murphy Oil Company. Earlier in his career, he held technical and management positions with Maxx Petroleum, Central Resources (USA), BP Resources Canada and Husky Oil. Mr. Proctor earned both Bachelor and Master of Science degrees in Petroleum Engineering from the University of Alberta, where his research focused on thermal oil recovery. Mr. Proctor is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, and is a member of the Canadian Heavy Oil Association and the Society of Petroleum Engineers.

Richard P. Ramsay was appointed Vice President, Alberta/B.C. Business Unit of Baytex on January 4, 2012. He originally joined Baytex Energy as Vice President, Heavy Oil on January 5, 2010. Mr. Ramsay has over 20 years of experience in the Canadian oil and gas industry and was formerly Chief Operating Officer of TAQA North Ltd. He previously held a variety of technical and management positions with Northrock Resources Ltd., Fletcher Challenge Energy Canada Inc., Amoco Canada Petroleum Ltd. and Dome Petroleum Ltd. Mr. Ramsay has a Bachelor of Science degree with Distinction in Mechanical Engineering from the University of Saskatchewan and is a practicing member of the Association of Professional Engineers, Geologists and Geophysists of Alberta.

Ownership of Securities by Management

As at March 1, 2012, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, approximately 1.6 million Common Shares, or approximately 1.4 percent of the issued and outstanding Common Shares. No Debentures were owned by this same group.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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

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

In addition, no director or executive officer of Baytex (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of our securities of to materially affect control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts

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

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

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

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

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

Pre-Approval of Policies and Procedures

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

External Auditor Service Fees

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by Deloitte & Touche LLP, our external auditors, during fiscal 2011 and 2010:

	Aggregate fees billed ($000s)	
	2011	2010
Audit Fees	$1,252	$848
Audit-Related Fees	—	—
Tax Fees	498	854
	$1,750	$1,702

Audit Fees: Audit fees consist of fees for the audit of our annual financial statements or services that are normally provided in connection with statutory and regulatory filings or engagements. In addition to the fees for annual audits of financial statements and review of quarterly results, services in this category for fiscal 2011 and 2010 also include amounts for audit work performed in relation to the requirements of Section 404 of the *Sarbanes-Oxley Act of 2002* relating to internal control over financial reporting, review of our documents and processes for the conversion of our consolidated financial statements to International Financial Reporting Standards and review of documentation relating to the Corporate Conversion.

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

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

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

Baytex is authorized to issue an unlimited number of Common Shares without nominal or par value and 10,000,000 preferred shares, without nominal or par value, issuable in series. As at the date of this Annual Information Form, there were no preferred shares outstanding.

The following is a summary of certain provisions of the share capital of Baytex. For a complete description of the share provisions, reference should be made to the Articles of Incorporation of Baytex, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on January 10, 2011).

Common Shares

Holders of Common Shares are entitled to notice of, to attend and to one vote per share held at any meeting of the shareholders of the Corporation (other than meetings of a class or series of shares of the Corporation other than the Common Shares as such).

Holders of Common Shares will be entitled to receive dividends as and when declared by the Board of Directors on the Common Shares as a class, subject to prior satisfaction of all preferential rights to dividends attached to shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of dividends.

Holders of Common Shares will be entitled in the event of any liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of the Corporation ranking in priority to the Common Shares in respect of return of capital on dissolution, to share rateably, together with the holders of shares of any other class of shares of the Corporation ranking equally with the Common Shares in respect of return of capital on dissolution, in such assets of the Corporation as are available for distribution.

Preferred Shares

The preferred shares May be issued in one or more series, at any time or from time to time. Before any shares of a particular series are issued, the Board of Directors will fix the number of shares that will form such series and will, subject to the limitations set out in the preferred share terms described below, fix the designation, rights, privileges, restrictions and conditions to be attached to the preferred shares of such series, including, but without in any way limiting or restricting the generality of the foregoing, the rate, amount or method of calculation of dividends thereon, the time and place of payment of dividends, the consideration for and the terms and conditions of any purchase for cancellation, retraction or redemption thereof, conversion or exchange rights (if any), and whether into or for securities of Baytex or otherwise, voting rights attached thereto (if any), the terms and conditions of any share purchase or retirement plan or sinking fund, and restrictions on the payment of dividends on any shares other than preferred shares or payment in respect of capital on any shares in the capital of Baytex or creation or issue of debt or equity securities; the whole subject to filing of Articles of Amendment setting forth a description of such series including the designation, rights, privileges, restrictions and conditions attached to the shares of such series. Notwithstanding the foregoing: (a) the Board of Directors May at any time or from time to time change the rights, privileges, restrictions and conditions attached to unissued shares of any series of preferred shares; and (b) other than in the case of a failure to declare or pay dividends specified in any series of the Preferred Share, the voting rights attached to the preferred shares will be limited to one vote per Preferred Share at any meeting where the preferred shares and Common Shares vote together as a single class.

The preferred shares of each series will rank on a parity with the preferred shares of every other series with respect to accumulated dividends and return of capital. The preferred shares will be entitled to a preference over the Common Shares and over any other shares of Baytex ranking junior to the preferred shares with respect to priority in the payment of dividends and in the distribution of assets in the event of the liquidation, dissolution or winding-up of Baytex, whether voluntary or involuntary, or any other distribution of the assets of Baytex among its shareholders for the purpose of winding-up its affairs. If any cumulative dividends or amounts payable on a return of capital are not paid in full, the preferred shares of all series will participate rateably in respect of such dividends, including accumulations, if any, in accordance with the sums that would be payable on such shares if all such dividends were declared and paid in full, and in respect of any repayment of capital in accordance with the sums that would be payable on such repayment of capital if all sums so payable were paid in full; provided, however, that in the event of there being insufficient assets to satisfy in full all such claims as aforesaid, the claims of the holders of the preferred shares with respect to repayment of capital will first be paid and satisfied and any assets remaining thereafter shall be applied towards the payment in satisfaction of claims in respect of dividends. The preferred shares of any series May also be given such other preferences not inconsistent with the terms of the preferred shares over the Common Shares and any other shares ranking junior to the preferred shares as May be determined in the case of each such series of preferred shares.

The rights, privileges, restrictions and conditions attaching to the preferred shares May be repealed, altered, modified, amended or amplified or otherwise varied only with the sanction of the holders of the preferred shares given in such manner as May then be required by law, subject to a minimum requirement that such approval be given by resolution passed by the affirmative vote of a least two-thirds of the votes cast at a meeting of holders of preferred shares duly called for such purpose and held upon at least 21 days' notice at which a quorum is present comprising at least two persons present, holding or representing by proxy at least 10% per cent of the outstanding preferred shares or by a resolution in writing of all holders of the outstanding preferred shares. If any such quorum is not present within half an hour after the time appointed for the meeting, then the meeting shall be adjourned to a date being not less than 7 days later and at such time and place as May be appointed by the chairman and at such meeting a quorum will consist of that number of shareholders present in person or represented by proxy. The formalities to be observed with respect to the giving of notice of any such meeting or adjourned meeting and the conduct thereof shall be those which May from time to time be prescribed in the by-laws of Baytex with respect to meetings of Shareholders. On every vote taken at every such meeting or adjourned meeting each holder of a Preferred Share shall be entitled to one vote in respect of each one dollar of stated value of preferred shares held.

Debentures

On August 26, 2009, the Trust issued $150 million principal amount of 9.15% series A senior unsecured debentures. The 2016 Debentures pay interest semi-annually and mature on August 26, 2016 at which time they are due and payable. The 2016 Debentures are unsecured and therefore, for all practical purposes, are subordinate to the Credit Facilities. After August 26 of each of the following years, the 2016 Debentures are redeemable at our option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the 2016 Debentures) plus accrued and unpaid interest thereon, if any: 2012 at 104.575%; 2013 at 103.050%; 2014 at 101.525%; and 2015 at 100%. In connection with the Corporate Conversion, Baytex assumed all of the rights and obligations of the Trust under the Debenture Indenture.

On February 17, 2011, we issued US$150 million principal amount of 6.75% series B senior unsecured debentures. The 2021 Debentures pay interest semi-annually and mature on February 21, 2017 at which time they are due and payable. The 2021 Debentures are unsecured and therefore, for all practical purposes, are subordinate to the Credit Facilities. After February 17 of each of the following years, the

2021 Debentures are redeemable at our option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the 2021 Debentures) plus accrued and unpaid interest thereon, if any: 2016 at 103.375%; 2017 at 102.250%; 2018 at 101.125%; and 2019 at 100%.

For a complete description of the Debentures, reference should be made to the Debenture Indenture, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on January 1, 2011 and February 22, 2011).

Credit Facilities

As at March 1, 2012, Baytex Energy had a $40 million extendible operating loan facility with a chartered bank and a $660 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility for a three-year term (to June 14, 2014), which is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time). The Credit Facilities contain standard commercial covenants for facilities of this nature. The Credit Facilities do not require any mandatory principal payments during the three-year term. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The Credit Facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain material restricted subsidiaries. The Credit Facilities do not include a term-out feature or a borrowing base restriction. In the event that we do not comply with covenants under the Credit Facilities, our ability to pay dividends to Shareholders may be restricted. See *"Dividends — Dividend Policy"*.

The Credit Facilities contain restrictions on Baytex Energy's ability to make distributions to us, including the declaration or payment of any dividend or distribution to us as the holder of the capital stock of Baytex Energy and the payment of interest or principal on subordinated debt owed to us. Baytex Energy and its subsidiaries are restricted from making distributions to us when (i) a default or event of default under the Credit Facilities has occurred and is continuing, or (ii) distributions would be reasonably expected to have a material adverse effect on or impair the ability of Baytex Energy to fulfill its financial obligations to its lenders under the Credit Facilities. See also "*Risk Factors — Risks Related to our Business and Operations — Our bank credit facilities will need to be renewed prior to June 14, 2014 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition*".

DIVIDENDS

Dividend Policy

Our dividend policy is to pay a monthly dividend on our Common Shares on or about the 15^{th} day following the end of each calendar month to Shareholders of record on or about the last business day of each such calendar month. Our dividend policy follows the general corporate philosophy of financial self sufficiency whereby, over the long term, development capital expenditures and dividend payments are planned to be financed from internally generated funds from operations. Unless otherwise indicated, all dividends paid or to be paid on our common shares are designated as "eligible dividends" for Canadian income tax purposes.

The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2011, our legal stated capital was approximately $1.6 billion. Cash dividends to Shareholders are not assured or guaranteed and there can be no guarantee that Baytex will maintain its dividend policy. See " — *Record of Dividends and Distributions*" and "*Risk Factors*".

Pursuant to the Credit Facilities, we are restricted from paying dividends to Shareholders if a default or event of default has occurred and is continuing and, if no default or event of default has occurred which is continuing, where the dividend would or would reasonably be expected to have a material adverse effect on us or on our or our subsidiaries' ability to fulfill their obligations under the Credit Facilities or under any hedge agreements with lenders (or their affiliates) under the Credit Facilities.

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

Cash dividends are not guaranteed. Our historical cash dividends (and the Trust's historical cash distributions) may not be reflective of future cash dividends, which will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time. Although we intend to pay dividends to Shareholders, these cash dividends may be reduced or suspended. The actual amount distributed will depend on numerous factors, including profitability, debt covenants and obligations, fluctuations in working capital, the timing and amount of capital expenditures, applicable law and other factors beyond our control. See "*Risk Factors*".

Record of Dividends and Distributions

Our dividend policy is to pay a monthly dividend on our Common Shares on or about the 15th day following the end of each calendar month to Shareholders of record on or about the last business day of each such calendar month. See "*Dividends — Dividend Policy*". The following table sets forth the Common Share dividends that we have paid.

Month	Dividends per Common Share ($) 2012	2011
January	0.22	0.20
February	0.22	0.20
March		0.20
April		0.20
May		0.20
June		0.20
July		0.20
August		0.20
September		0.20
October		0.20
November		0.20
December		0.22
Total		$2.42

Our predecessor, the Trust, paid a monthly distribution on its Trust Units on or about the 15th day following the end of each calendar month to unitholders of record on or about the last business day of each such calendar month. The following table sets forth the distributions paid by the Trust from September 2003 to December 2010.

	Distributions per Trust Unit ($)							
Month	2010	2009	2008	2007	2006	2005	2004	2003
January	0.18	0.18	0.18	0.18	0.18	0.15	0.15	—
February	0.18	0.12	0.18	0.18	0.18	0.15	0.15	—
March	0.18	0.12	0.20	0.18	0.18	0.15	0.15	—
April	0.18	0.12	0.20	0.18	0.18	0.15	0.15	—
May	0.18	0.12	0.20	0.18	0.18	0.15	0.15	—
June	0.18	0.12	0.25	0.18	0.18	0.15	0.15	—
July	0.18	0.12	0.25	0.18	0.18	0.15	0.15	—
August	0.18	0.12	0.25	0.18	0.18	0.15	0.15	—
September	0.18	0.12	0.25	0.18	0.18	0.15	0.15	0.15
October	0.18	0.12	0.25	0.18	0.18	0.15	0.15	0.15
November	0.18	0.12	0.25	0.18	0.18	0.15	0.15	0.15
December	0.20	0.18	0.18	0.18	0.18	0.15	0.15	0.15
Total	$2.18	$1.56	$2.64	$2.16	$2.16	$1.80	$1.80	$0.60

Dividend Reinvestment Plan

Baytex has a Dividend Reinvestment Plan (the "**DRIP**") that provides a convenient and cost-effective method for eligible holders in Canada and the United States to maximize their investment in Baytex by reinvesting their monthly cash dividends to acquire additional Common Shares. At the discretion of Baytex, Common Shares will either be issued from treasury or acquired in the open market at prevailing market prices. Pursuant to the terms of the DRIP, Common Shares issued from treasury are currently issued at a three percent discount to the "average market price" (as defined in the DRIP).

Baytex reserves the right at any time to change or eliminate the discount on Common Shares acquired from treasury. Shareholders are not required to participate in the DRIP. A Shareholder who does not participate will continue to receive monthly cash dividends on their Common Shares in the normal manner.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "BTE". The Common Shares commenced trading on the TSX on January 7, 2011 and on the NYSE on January 3, 2011. The following table sets forth certain trading information for the Common Shares in Canada and the United States for the periods indicated.

	Canada Composite Trading			**United States Composite Trading**		
	Price Range			**Price Range**		
	High ($)	**Low ($)**	**Volume Traded**	**High ($US)**	**Low ($US)**	**Volume Traded**
2011						
January[(1)]	49.75	46.00	20,805,126	49.81	46.25	4,567,720
February	56.04	49.32	10,874,364	57.63	49.66	4,075,803
March	56.95	48.52	11,188,097	58.53	49.03	7,234,228
April	58.55	55.52	9,129,670	61.74	57.17	4,175,426
May	58.77	49.81	12,381,539	61.96	50.93	9,048,802
June	55.83	47.59	14,193,634	57.54	48.62	6,851,135
July	55.93	50.70	8,231,379	59.04	52.39	5,339,883
August	53.62	43.45	15,922,282	57.22	43.71	10,478,705
September	50.84	41.71	15,526,773	51.94	40.30	8,665,835
October	54.97	39.18	16,429,558	55.30	36.89	8,235,141
November	54.78	49.14	13,311,944	54.04	47.07	5,519,328
December	57.26	51.70	10,205,150	56.40	49.65	5,250,886
2012						
January	59.40	54.13	10,735,168	59.27	52.85	4,342,870
February	59.27	54.86	10,633,575	59.50	54.80	3,430,316

Note:

(1) The trading data for the Toronto Stock Exchange is for the period from January 7 to 31, 2011. The trading data for United States Composite Trading is for the period from January 3 to 31, 2011.

In connection with the Corporate Conversion, effective December 31, 2010, holders of Trust Units exchanged their Trust Units for Common Shares on a one-for-one basis. From September 8, 2003 to January 5, 2011, the Trust Units were listed and posted for trading on the TSX under the trading symbol "BTE.UN". From March 27, 2006 to December 31, 2010, the Trust Units were listed and posted for trading on the NYSE under the trading symbol "BTE". The following table sets forth certain trading information for the Trust Units in Canada and the United States for the periods indicated.

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High ($US)	Low ($US)	Volume Traded
2003	10.89	9.19	40,973,662	—	—	—
2004	14.00	9.78	93,252,808	—	—	—
2005	18.78	12.42	87,481,272	—	—	—
2006	28.66	16.81	102,652,240	25.87	16.63	33,615,100
2007	22.92	16.68	86,189,613	21.75	15.51	46,189,896
2008	35.37	12.81	123,670,870	35.20	9.81	97,403,098
2009	30.50	9.77	123,555,826	29.33	7.84	88,314,675
2010	48.18	27.72	133,959,260	47.92	25.00	52,968,182
2011						
January (1-6)	47.63	46.55	3,899,246	—	—	—

RATINGS

The following information relating to our credit ratings is provided as it relates to our financing costs, liquidity and operations. Specifically, credit ratings affect our ability to obtain short-term and long-term financing and the cost of such financing. A reduction in our current credit ratings by the rating agencies, particularly a downgrade below the current ratings or a negative change in the ratings outlook, could adversely affect our cost of financing and our access to sources of liquidity and capital. In addition, changes in credit ratings may affect our ability to, and the associated costs of, (i) enter into ordinary course derivative or hedging transactions and may require us to post additional collateral under certain of its contracts, and (ii) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

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

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

Valiant Trust Company, at its principal offices in Calgary, Alberta and Toronto, Ontario, is the transfer agent and registrar for the Common Shares and the Debentures in Canada. Registrar and Transfer Company, at its principal office in Cranford, New Jersey, is the transfer agent and registrar for the Common Shares in the United States.

INTERESTS OF EXPERTS

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

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

MATERIAL CONTRACTS

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

(a) the credit agreement in respect of the Credit Facilities (filed on SEDAR on July 22, 2011);

(b) the Debenture Indenture (filed on SEDAR on January 1, 2011 and February 22, 2011);

(c) our share award incentive plan (filed on SEDAR on February 22, 2012); and

(d) our common share rights incentive plan (filed on SEDAR on January 10, 2011).

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

INDUSTRY CONDITIONS

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

Pricing and Marketing

Oil

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

Natural Gas

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

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

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

Occasionally the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are introduced to encourage exploration and development activity generally or to encourage development of targeted resources.

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010.

Royalty rates for conventional oil are set by a single sliding rate formula which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $535/m^3$ compared to the previous royalty curve.

Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

Oil sands projects are also subject to the Alberta's royalty regime. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range from 1% to 9% depending on the market price of oil, determined using the average monthly price, expressed in Canadian dollars, for WTI crude oil at Cushing, Oklahoma: rates are 1% when the market price of oil is less than or equal to $55 per barrel and increases for every dollar of market price of oil increase to a maximum of 9% when oil is priced at $120 per barrel or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of 1% to 9% and the net revenue royalty based on the net revenue royalty rate. The rate for the net revenue royalty is 25% when the price for WTI crude oil at Cushing, Oklahoma, expressed in Canadian dollars, is less than or equal to $55 per barrel. The net revenue royalty increases when the market price exceeds $55 per barrel to a maximum of 40% of net revenue when the oil price is equal to or greater than $120 per barrel. In addition, concurrently with the implementation of the New Royalty Framework, the Government of Alberta renegotiated existing contracts with certain oil sands producers that were not compatible with the current royalty regime.

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 and are intended to encourage the development of deeper, higher cost oil and gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. All remaining credits from this program expired in 2011. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

In addition to the foregoing, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources (the "**Emerging Resource and Technologies Initiative**"). Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

The Emerging Resource and Technologies Initiative will be reviewed in 2014, and the Government of Alberta has committed to providing industry with three years notice at that time if it decides to discontinue the program.

British Columbia

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

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

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

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

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

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

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

- *Deep Discovery Royalty Credit Program* providing the lesser of a 3-year royalty holiday or 283,000,000 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation with a spud date after November 30, 2003;

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

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

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; and

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

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

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

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

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

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

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

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

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

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

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

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

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

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

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

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for the flaring and venting of associated gas (the "**Associated Natural Gas Standards**"). The Associated Natural Gas Standards were jointly developed with industry and the implementation of such standards is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

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, and on conditions set forth in provincial legislation including requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

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

In December, 2008, the Government of Alberta released a new land use policy for surface land in Alberta, the Alberta Land Use Framework (the "**ALUF**"). The ALUF sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of region-specific land use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be deemed to be legislative instruments equivalent to regulations and will be binding on the Government of Alberta and provincial regulators, including those governing the oil and gas industry. In the event of a conflict or inconsistency between a regional plan and another regulation, regulatory instrument or statutory consent, the regional plan will prevail. Further, the ALSA requires local governments, provincial departments, agencies and administrative bodies or tribunals to review their regulatory instruments and make any appropriate changes to ensure that they comply with an adopted regional plan. The ALSA also contemplates the amendment or extinguishment of previously issued statutory consents such as regulatory permits, leases, licenses, approvals and authorizations for the purpose of achieving or maintaining an objective or policy resulting from the implementation of a regional plan. Among the measures to support the goals of the regional plans contained in the ALSA are conservation easements, which can be granted for the protection, conservation and enhancement of land; and conservation directives, which are explicit declarations contained in a regional plan to set aside specified lands in order to protect, conserve, manage and enhance the environment.

On August 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas.

However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

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

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

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

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

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

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

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it through the *Climate Change and Emissions Management Amendment Act* which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

As at year-end 2011, Baytex did not have an interest in any facilities in Alberta that emit more than 100,000 tonnes of CO_2 equivalents per year.

British Columbia

In February, 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $25 per tonne of CO_2 equivalent. It is scheduled to increase to $30 per tonne of CO_2 equivalent on July 31, 2012. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**") which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO_2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO_2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

As at year-end 2011, Baytex's Cache Creek facility emitted more than 10,000 tonnes of CO_2 equivalents per year and, therefore, will be subject to reporting requirements under the Cap and Trade Act. As at year-end 2011, Baytex did not have an interest in any facilities in British Columbia that emit more than 25,000 tonnes of CO_2 equivalents per year.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

United States

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

ADDITIONAL INFORMATION

Additional information relating to us can be found on the SEDAR website at *www.sedar.com* and on our website at *www.baytex.ab.ca.* Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our Information Circular — Proxy Statement for the annual meeting of Shareholders to be held on May 15, 2012. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2011 and the related management's discussion and analysis which are accessible on the SEDAR website at *www.sedar.com*. For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

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APPENDIX A

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

Management of Baytex Energy Corp. ("**Baytex**") is responsible for the preparation and disclosure of information with respect to Baytex's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

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

The Reserves Committee of the Board of Directors of Baytex (the "**Reserves Committee**") 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 has reviewed Baytex's procedures for assembling and reporting other information associated with oil and natural gas activities and has reviewed that information with management. The Board of Directors of Baytex has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

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

(signed) "*Anthony W. Marino*"

Anthony W. Marino
President and Chief Executive Officer

(signed) "*W. Derek Aylesworth*"

W. Derek Aylesworth
Chief Financial Officer

(signed) "*Dale O. Shwed*"

Dale O. Shwed
Director and Chairman of the Reserves Committee

(signed) "*John A. Brussa*"

John A. Brussa
Director and Member of the Reserves Committee

March 15, 2012

APPENDIX B

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

To the Board of Directors of Baytex Energy Corp. ("**Baytex**"):

1. We have evaluated Baytex's reserves data as at December 31, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Baytex evaluated by us for the year ended December 31, 2011, and identifies the respective portions thereof that we have evaluated and reported on to the management and Board of Directors of Baytex:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves	Net Present Value of Future Net Revenue Before income taxes (10% discount rate — $ millions)			
			Audited	**Evaluated**	**Reviewed**	**Total**
Sproule Associates Limited	Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2011). Preparation Date: March 7, 2012	Canada	Nil	$4,426,617	Nil	$4,426,617
		United States	Nil	389,646	Nil	389,646
		Total	Nil	$4,816,263	Nil	$4,816,263

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, consistently applied.

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

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

Executed as to our report referred to above on March 15, 2012.

Sproule Associates Limited

(signed) "*Cameron P. Six*"	(signed) "*Alec Kovaltchouk*"
Cameron P. Six, P.Eng. Vice-President, Engineering and Partner	Alec Kovaltchouk, P.Geol Manager, Geoscience and Partner
(signed) "*Peter C. Sidey*"	(signed) "*Donald W. Woods*"
Peter C. Sidey, P.Eng. Partner	Donald W. Woods, P.Eng. Manager, Engineering and Partner

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

The objectives of the Committee are to:

2. assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;
3. facilitate communication between directors and the external auditors;
4. enhance the external auditors' independence;
5. increase the credibility and objectivity of financial reports; and
6. strengthen the role of the independent directors by facilitating in depth discussions between the Committee, management and the external auditors.

MEMBERSHIP OF THE COMMITTEE

1. The Committee shall be comprised of not less than three members all of whom are "independent" directors and "financially literate" (within the meaning of National Instrument 52-110 "Audit Committees"). The members of the Committee shall be appointed by the Board from time to time.
2. The Board shall appoint a Chair of the Committee, who shall be an independent director.
3. Any member of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee as soon as such member ceases to be a director. The Board may fill vacancies on the Committee by appointment from among its members. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, each member of the Committee shall hold such office until the close of the next annual meeting of shareholders of the Corporation following appointment as a member of the Committee.

MANDATE AND RESPONSIBILITIES OF THE COMMITTEE

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

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

   - identifying, monitoring and mitigating business risks; and
   - ensuring compliance with legal, ethical and regulatory requirements.

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

   - reviewing changes in accounting principles, or in their application, which may have a material impact on the current or future years' financial statements;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between management and the external auditors;
   - obtaining explanations of significant variances with comparative reporting periods; and
   - determining through inquiry if there are any related party transactions and ensuring that the nature and extent of such transactions are properly disclosed.

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

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

   - recommend to the Board the appointment of the external auditors, including the terms of their engagement for the integrated audit;
   - review and approve any other services to be provided by the external auditors (including the fee for such services); and
   - when there is to be a change in the external auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

6. Review with the external auditors (and the internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for the audit and, upon completion of the audit, their reports upon the financial

statements of the Corporation and its subsidiaries.

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

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

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

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

11. The Committee shall have the authority to investigate any financial activity of the Corporation. All employees of the Corporation and its subsidiary entities are to cooperate as requested by the Committee.

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

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

MEETINGS AND ADMINISTRATIVE MATTERS

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

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

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

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

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

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

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

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

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

Approved by the Board of Directors on February 28, 2011

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. is responsible for establishing and maintaining adequate internal control over financial reporting over the Company. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on our assessment, we have concluded that as of December 31, 2011, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011 has been audited by Deloitte & Touche LLP, the Company's Independent Registered Chartered Accountants, who also audited the Company's Consolidated Financial Statements for the year ended December 31, 2011.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Baytex Energy Corp. 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 Company's shareholders to express an audit 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 IFRS.

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 Deloitte & Touche LLP and reviews their fees. The Independent Registered Chartered Accountants have access to the Audit Committee without the presence of management.

Anthony W. Marino
President and Chief Executive Officer
Baytex Energy Corp.

W. Derek Aylesworth
Chief Financial Officer
Baytex Energy Corp.

March 13, 2012

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Baytex Energy Corp.

We have audited the accompanying consolidated financial statements of Baytex Energy Corp. and subsidiaries (the "Company"), which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, and the consolidated statements of income and comprehensive income, statements of changes in equity, and statements of cash flows for the years ended December 31, 2011 and December 31, 2010, and the notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Baytex Energy Corp. and subsidiaries as at December 31, 2011, December 31, 2010 and January 1, 2010 and their financial performance and cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Other Matter

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated March 13, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Calgary, Canada
March 13, 2012

Independent Registered Chartered Accountants

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Board of Directors and Shareholders of Baytex Energy Corp.

We have audited the internal control over financial reporting of Baytex Energy Corp. and subsidiaries (the "Company") as of December 31, 2011, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company and our report dated March 13, 2012 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Calgary, Canada
March 13, 2012

Independent Registered Chartered Accountants

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	December 31, 2011	December 31, 2010	January 1, 2010
(thousands of Canadian dollars)			
ASSETS			
Current assets			
Cash	$ 7,847	$ –	$ 10,177
Trade and other receivables (note 6)	206,951	151,792	137,154
Crude oil inventory	898	1,802	1,384
Financial derivatives (note 23)	10,879	13,921	29,453
	226,575	167,515	178,168
Non-current assets			
Deferred income tax asset (note 19)	10,133	7,870	1,789
Financial derivatives (note 23)	180	2,622	2,541
Exploration and evaluation asset (note 7)	129,774	113,082	124,621
Oil and gas properties (note 8)	2,032,160	1,624,629	1,512,035
Other plant and equipment (note 9)	25,233	27,550	27,096
Goodwill (note 10)	37,755	37,755	37,755
	$ 2,461,810	$ 1,981,023	$ 1,884,005
LIABILITIES			
Current liabilities			
Trade and other payables (note 12)	$ 225,831	$ 183,314	$ 186,516
Dividends or distributions payable to shareholders/unitholders	25,936	22,742	19,674
Bank loan (note 11)	–	–	265,088
Convertible debentures (note 14)	–	–	7,736
Financial derivatives (note 23)	25,205	20,312	12,004
	276,972	226,368	491,018
Non-current liabilities			
Bank loan (note 11)	311,960	303,773	–
Long-term debt (note 13)	297,731	146,893	146,498
Asset retirement obligations (note 15)	260,411	169,611	141,869
Unit-based payment liability (note 17)	–	–	91,559
Deferred income tax liability (note 19)	93,217	14,383	160,719
Financial derivatives (note 23)	14,785	8,859	1,418
	1,255,076	869,887	1,033,081
SHAREHOLDERS'/UNITHOLDERS' EQUITY			
Shareholders' capital (note 16)	1,680,184	1,484,335	–
Unitholders' capital (note 16)	–	–	1,331,161
Contributed surplus	85,716	129,129	–
Accumulated other comprehensive loss	(3,546)	(10,323)	–
Deficit	(555,620)	(492,005)	(480,237)
	1,206,734	1,111,136	850,924

	$	2,461,810	$	1,981,023	$	1,884,005

Commitments and contingencies (note 26)

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director, Baytex Energy Corp.

Gregory K. Melchin
Director, Baytex Energy Corp.

CONSOLIDATED STATEMENTS OF INCOME
AND COMPREHENSIVE INCOME

Years Ended December 31		2011		2010
(thousands of Canadian dollars, except per common share and per trust unit amounts)				
Revenues, net of royalties (note 20)	$	1,096,642	$	834,292
Expenses				
Exploration and evaluation		13,865		24,502
Production and operating		209,177		171,704
Transportation and blending		249,850		188,591
General and administrative		39,335		40,747
Share-based or unit-based compensation (note 17)		33,845		94,199
Financing costs (note 21)		44,611		34,570
Gain on divestitures of oil and gas properties		(37,946)		(16,227)
Loss (gain) on financial derivatives (note 23)		18,030		(4,817)
Foreign exchange loss (gain) (note 22)		7,834		(9,148)
Depletion and depreciation (note 8 & 9)		248,468		202,796
		827,069		726,917
Net income before income taxes		269,573		107,375
Deferred income tax expense (recovery) (note 19)		52,141		(124,240)
Net income attributable to shareholders/unitholders	$	217,432	$	231,615
Other comprehensive income (loss)				
Foreign currency translation adjustment		6,777		(10,323)
Comprehensive income attributable to shareholders/unitholders	$	224,209	$	221,292
Net income per common share or trust unit (note 18)				
Basic	$	1.88	$	2.08
Diluted	$	1.83	$	2.01
Weighted average common shares or trust units (note 18)				
Basic		115,960		111,450
Diluted		118,921		115,151

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

(thousands of Canadian dollars)	Shareholders' capital	Unitholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	Total equity
Balance at January 1, 2010	$ –	$ 1,331,161	$ –	$ –	$ (480,237)	$ 850,924
Distributions to unitholders	–	–	–	–	(243,383)	(243,383)
Issued on conversion of debentures	–	19,897	–	–	–	19,897
Exercise of unit rights	–	82,649	–	–	–	82,649
Issued pursuant to distribution reinvestment plan	–	51,699	–	–	–	51,699
Comprehensive income (loss) for the period	–	–	–	(10,323)	231,615	221,292
Change in effective tax rate on issue costs	–	(1,071)	–	–	–	(1,071)
Exchanged for shares, pursuant to the Arrangement	1,484,335	(1,484,335)	129,129	–	–	129,129
Balance at December 31, 2010	$ 1,484,335	$ –	$ 129,129	$ (10,323)	$ (492,005)	$ 1,111,136
Dividends to shareholders	–	–	–	–	(281,047)	(281,047)
Exercise of share rights	122,306	–	(77,258)	–	–	45,048
Share-based compensation	–	–	33,845	–	–	33,845
Issued pursuant to dividend reinvestment plan	73,543	–	–	–	–	73,543
Comprehensive income for the period	–	–	–	6,777	217,432	224,209
Balance at December 31, 2011	$ 1,680,184	$ –	$ 85,716	$ (3,546)	$ (555,620)	$ 1,206,734

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31	2011	2010
(thousands of Canadian dollars)		
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income for the year	$ 217,432	$ 231,615
Adjustments for:		
Share-based or unit-based compensation (note 17)	33,845	94,199
Unrealized foreign exchange loss (gain) (note 22)	8,490	(8,999)
Exploration and evaluation	10,130	18,913
Depletion and depreciation	248,468	202,796
Unrealized loss on financial derivatives (note 23)	16,166	43,312
Gain on divestitures of oil and gas properties	(37,946)	(16,227)
Deferred income tax expense (recovery) (note 19)	52,141	(124,240)
Financing costs (note 21)	44,611	34,570
Change in non-cash working capital (note 22)	(10,889)	(11,704)
Asset retirement expenditures (note 15)	(10,588)	(2,829)
	571,860	461,406
Financing activities		
Payments of dividends or distributions	(204,308)	(188,615)
Increase in bank loan	4,290	48,045
Proceeds from issuance of long-term debt (note 13)	145,810	–
Repayment of convertible debentures (note 14)	–	(341)
Issuance of common shares or trust units (note 16)	45,048	26,021
Interest paid	(34,730)	(28,499)
	(43,890)	(143,389)
Investing activities		
Additions to exploration and evaluation assets (note 7)	(9,104)	(37,411)
Additions to oil and gas properties	(358,744)	(194,208)
Property acquisitions	(76,164)	(22,412)
Corporate acquisitions (note 5)	(120,006)	(40,314)
Proceeds from divestitures	47,396	19,033
Additions to other plant and equipment, net of disposals (note 9)	(1,252)	(8,237)
Acquisition of financing entities (note 19)	–	(38,000)
Change in non-cash working capital (note 22)	(2,553)	(5,956)
	(520,427)	(327,505)
Impact of foreign currency translation on cash balances	304	(689)
Change in cash	7,847	(10,177)
Cash, beginning of year	–	10,177
Cash, end of year	$ 7,847	$ –

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 - 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 - 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

Baytex Energy Trust (the "Trust") completed the conversion of its legal structure from an income trust to a corporation at year-end 2010 pursuant to a Plan of Arrangement under the Business Corporations Act (Alberta) (the "Arrangement"). Pursuant to the Arrangement, (i) on December 31, 2010, the trust units of the Trust were exchanged for common shares of Baytex on a one-for-one basis and (ii) on January 1, 2011, the Trust was dissolved and terminated, with Baytex being the successor to the Trust. The reorganization into a corporation has been accounted for on a continuity of interest basis, and accordingly, the consolidated financial statements reflect the financial position, results of operations and cash flows as if the Company had always carried on the business formerly carried on by the Trust.

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Canadian generally accepted accounting principles have been revised to incorporate IFRS and publicly accountable enterprises are required to apply such standards for years beginning on or after January 1, 2011. Accordingly, these consolidated financial statements were prepared in accordance with IFRS 1, First-time Adoption of IFRS. The significant accounting policies set out below were consistently applied to all the periods presented.

In these financial statements, the term "previous GAAP" refers to Canadian generally accepted accounting principles prior to the adoption of IFRS. Previous GAAP differs in some areas from IFRS. In preparing these consolidated financial statements, management has amended certain accounting, valuation and consolidation methods applied in the previous GAAP financial statements to comply with IFRS. The date of transition to IFRS was January 1, 2010 and the comparative figures for 2010 were restated to reflect these adjustments. Reconciliations and descriptions of the effect of the transition from previous GAAP to IFRS on equity, net income and comprehensive income are included in note 29.

The consolidated financial statements were approved and authorized by the Board of Directors on March 13, 2012.

The consolidated financial statements have been prepared on the historical cost basis, except for derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is rounded to the nearest thousand, except per share or per trust unit amounts and when otherwise indicated.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. The date of acquisition is the date on which the Company obtains control and the subsidiary companies continue to be consolidated until the date such control ceases. Control exists when the Company has the ability to direct the activities of an entity to generate returns from its activities. Inter-company transactions and balances are eliminated upon consolidation. A portion of the Company's exploration, development and production activities is conducted jointly with others and involve jointly controlled assets. These jointly controlled assets are accounted for using the proportionate consolidation method whereby the consolidated financial statements reflect only the Company's proportionate interest.

Operating Segments Reporting

Baytex's operations are grouped into one operating segment for reporting consistent with the internal reporting provided to the chief operating decision-maker of the Company.

Measurement Uncertainty and Judgements

The preparation of the consolidated financial statements requires management to make judgements, 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 revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depletion of oil and gas properties are based on a unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. The Company's total proved plus probable reserves are estimated annually using independent reserve engineer reports and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent or greater statistical probability of being recovered. Due to the inherent uncertainties and the necessarily limited nature of reservoir data, estimates of reserves are inherently imprecise, require the application of judgement and are subject to change as additional information becomes available. The impact of future changes to estimates on the consolidated financial statements of subsequent periods could be material.

Amounts recorded for depreciation are based on estimated useful lives of depreciable assets; management reviews these estimates at each reporting date.

The Company's capital assets are aggregated into cash-generating units based on their ability to generate largely independent cash flows and are used for impairment testing. The definition of the Company's cash-generating units is subject to management's judgement.

Impairment of assets and group of assets are calculated based on the higher of value-in-use calculations and fair value less costs to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and natural gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. The Company assesses internal and external indicators of impairment in determining whether the carrying values of the assets may not be recoverable.

Fair value of financial instruments, where active market quotes are not available are estimated using the Company's assessment of available market inputs and are described in note 23. These estimates may vary from the actual prices that will be achieved upon settlement of the financial instruments.

Fair values of share-based compensation are measured at the later of grant date or December 31, 2010, taking into consideration management's best estimate of the number of shares that will vest. Fair values of unit-based compensation were remeasured at each reporting date until the December 31, 2010 corporate conversion using a binomial-lattice pricing model, taking into consideration management's best estimate of the expected volatility, expected life of the option and estimated number of units that will vest.

The amounts recorded for asset retirement obligations are estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future and the discount and inflation rates. 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.

The Company is engaged in litigation and claims arising in the normal course of operations where the actual outcome may vary from the amount recognized in the consolidated financial statements. None of these claims could reasonably be expected to materially affect the Company's financial position or reported results of operations.

Tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. As such, income taxes are subject to measurement uncertainty.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The cost of an acquisition is measured as cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed, including contingent liabilities are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. Any deficiency of the cost of acquisition below the fair values of the identifiable net assets acquired is credited to net income in the statements of income and comprehensive income in the period of acquisition. Associated transaction costs are expensed when incurred.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the reporting date, is valued at the lower of cost, using the weighted average cost method, or net realizable value. Costs include direct and indirect expenditures incurred in bringing the crude oil to its existing condition and location.

Exploration and Evaluation Assets, Oil and Gas Properties and Other Plant and Equipment

a) <u>Pre-license Costs</u>

Pre-license costs are costs incurred before the legal rights to explore a specific area have been obtained. These costs are expensed in the period in which they are incurred.

b) <u>Exploration and Evaluation ("E&E") Costs</u>

Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well program/project is complete and the results have been evaluated. Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing. E&E costs are not depleted and are carried forward until technical feasibility and commercial viability of extracting a mineral resource is considered to be determined. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determined when proved and/or probable reserves are determined to exist. All such carried costs are subject to technical, commercial and management review quarterly to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the impairment costs are charged to exploration and evaluation expense. Upon determination of proven and/or probable reserves, E&E assets attributable to those reserves are first tested for impairment and then reclassified to oil and gas properties.

c) <u>Development Costs</u>

Costs incurred subsequent to the determination of technical feasibility and commercial viability are recognized as oil and gas properties only when they increase the future economic benefits embodied in the specific asset to which they relate. Such capitalized petroleum and natural gas interests generally represent costs incurred in developing proved and/or probable reserves and bringing in or enhancing production from such reserves and are accumulated on a geotechnical area basis.

Major maintenance and repairs consist of the cost of replacement assets or parts of assets, inspection costs and overhaul costs. Where an asset or part of an asset that was separately depreciated and has been completely written off is replaced and it is probable that there are future economic benefits associated with the item, the expenditure is capitalized. The costs of the day-to-day servicing of property, plant and equipment are recognized in net income as incurred.

The carrying amount of any replaced or sold component of an oil and gas property is derecognized and included in net income in the period in which the item is derecognized.

d) Borrowing Costs and Other Capitalized Costs

Borrowing costs that are directly attributable to the acquisition, construction or production of a qualifying asset form part of the cost of that asset. A qualifying asset is an asset that requires a period of one year or greater to get ready for its intended use or sale. Baytex has had no qualifying assets that would allow for borrowing costs to be capitalized to the asset. All such borrowing costs are expensed as incurred.

No general and administrative expenses have been capitalized since Baytex's inception.

e) Depletion and Depreciation

The net carrying value of oil and gas properties is depleted using the units of production method using estimated proved and probable petroleum and natural gas reserves, by reference to the ratio of production in the year to the related proven and probable reserves at forecast prices, taking into account estimated future development costs necessary to bring those reserves into production. 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 natural gas equates to one barrel of oil. Future development costs are estimated as the costs of development required to produce the reserves. These estimates are prepared by independent reserve engineers at least annually.

The depreciation methods and estimated useful lives for other assets for other plant and equipment are as follows:

Classification	Method	Rate or period
Motor Vehicles	Diminishing balance	15%
Office Equipment	Diminishing balance	20%
Computer Hardware	Diminishing balance	30%
Furniture and Fixtures	Diminishing balance	10%
Leasehold Improvements	Straight-line over life of the lease	Various
Other Assets	Diminishing balance	Various

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively.

Impairment of Non-financial Assets

The goodwill balance is assessed for impairment at least annually at year end or more frequently if events or changes in circumstances indicate that the asset may be impaired. E&E assets are assessed for impairment when they are reclassified to oil and gas properties and also if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The Company assesses other assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable.

Individual assets are grouped for impairment assessment purposes at the lowest level at which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets (the "cash-generating unit" or "CGU"). Goodwill acquired is allocated to CGUs expected to benefit from synergies of the related business combination.

If any such indication of impairment exists or when annual impairment testing for a CGU is required, the Company makes an estimate of its recoverable amount. A CGU's recoverable amount is the higher of its fair value less costs to sell and its value-in-use. In assessing value-in-use, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment amount reduces first the carrying amount of any goodwill allocated to the CGU. Any remaining impairment is allocated to the individual assets in the CGU on a pro rata basis. Impairment is charged to net income in the period in which it occurs.

For all assets excluding goodwill, an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment losses may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. A previously recognized impairment loss is reversed only if there has been a change in the estimates used to determine the asset's recoverable amount since the last impairment loss was recognized. If that is the case, the carrying amount of the asset is increased to its recoverable amount. That increased amount cannot exceed the carrying amount that would have been determined, net of depletion and depreciation, had no impairment loss been recognized for the asset in prior years. Such reversal is recognized in net income. After such a reversal, the depletion or depreciation charge is adjusted in future periods to allocate the asset's revised carrying amount, less any residual value, on a systematic basis over its remaining useful life. Impairment losses recognized in relation to goodwill are not reversed for subsequent increases in its recoverable amount.

Asset Retirement Obligations

The Company recognizes a liability at the discounted value for the future asset retirement costs associated with its oil and gas properties using the risk free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted to expense over its useful life. The discount in the liability unwinds until the date of expected settlement of the retirement obligations and is recognized as a finance cost in the statements of income and comprehensive income. The liability 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 statements of financial position.

Foreign Currency Translation

Transactions completed in foreign currencies are reflected in Canadian dollars at the foreign currency exchange rates prevailing at the time of the transactions. Monetary assets and liabilities denominated in foreign currencies are reflected in the statements of financial position at the Canadian equivalent at the foreign currency exchange rates prevailing at the reporting date. Foreign exchange gains and losses are included in net income.

Revenues and expenses of foreign operations are translated to Canadian dollars using average foreign currency exchange rates for the period. Monetary assets and liabilities that form part of the net investment in the foreign operation are translated at the period-end foreign currency exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders'/unitholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

Revenue Recognition

Revenue associated with sales of petroleum and natural gas is recognized when title passes to the purchaser at the pipeline delivery point. Revenue is measured net of discounts, customs duties and royalties. With respect to royalties, the Company is acting as a collection agent on behalf of the Crown and other royalty interest holders.

Revenue from the production of oil in which the Company has an interest with other producers is recognized based on the Company's working interest and the terms of the relevant joint venture agreements.

Financial Instruments

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: fair value through profit or loss ("FVTPL"), loans and receivables, held-to-maturity investments, available-for-sale financial assets or other financial liabilities.

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets are measured at fair value and changes in fair value are recognized in net income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income (loss) until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest method.

All risk management contracts are recorded in the statements of financial position at fair value unless they were entered into and continue to be held in accordance with the Company's expected purchase, sale and usage requirements. All changes in their fair value are recorded in net income unless cash flow hedge accounting is used, in which case changes in fair value are recorded in other comprehensive income until the underlying hedged transaction is recognized in net income. The Company has elected not to use cash flow hedge accounting on its risk management contracts with financial counterparties resulting in all changes in fair value being recorded in net income.

Cash is classified as FVTPL. Trade and other receivables are classified as loans and receivables, which are measured at amortized cost. Trade and other payables and the bank loan are classified as other financial liabilities, which are measured at amortized cost.

The convertible debentures have been classified as liabilities, net of the fair value of the conversion feature which has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the instrument are recognized in the net income. The liability component is classified as other financial liabilities. The liability component will accrete up to the principal balance at maturity. The accretion and the interest paid are reported as finance expense in the consolidated statements of income and comprehensive income (loss). If the debentures were converted to trust units, the fair value of the conversion feature would be reclassified to unitholders' capital along with the principal amounts converted.

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts are considered to consist of a host contract plus an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative. The Company has no material embedded derivatives.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability classified at FVTPL are expensed immediately. For a financial asset or financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to or deducted from the fair value on initial recognition and amortized through net income over the term of the financial instrument.

The Company 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 policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. The Company does not use financial derivatives for trading or speculative purposes. These instruments are classified as FVTPL unless designated for hedge accounting. The Company has not designated its financial derivative contracts as effective accounting hedges, and thus not applied hedge accounting. As a result, for all derivative instruments, the Company applies the fair value method of accounting by recording an asset or liability on the statements of financial position and recognizing changes in the fair value of the instrument in the statements of income and comprehensive income for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income when incurred.

The Company has accounted for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statements of financial position. Settlements on these physical sales contracts are recognized in revenue in the period of settlement.

Income Taxes

Current and deferred income taxes are recognized in net income, except when they relate to items that are recognized directly in equity. Where current and deferred income taxes are recognized directly in equity when

current income tax or deferred income tax arises from the initial accounting for a business combination, the tax effect is included in the accounting for the business combination.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted or substantively enacted at the end of the reporting period.

The Company follows the balance sheet liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all temporary differences deductible to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share Rights Plan and Share Award Incentive Plan

The Trust's Trust Unit Rights Incentive Plan (the "Unit Rights Plan"), which was superseded by the Company's Common Share Rights Incentive Plan (the "Share Rights Plan"), is described in note 17. The exercise price of the share rights under the Share Rights Plan may be reduced in future periods in accordance with the terms of the Share Rights Plan.

Prior to the conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability was re-measured at each reporting date and at settlement date. Any changes in fair value were recognized in net income for the period. The conversion of the outstanding unit rights to share rights in connection with the Arrangement effectively changed the related classification from a liability plan to an equity-settled plan. The expense recognized from the date of modification over the remainder of the vesting period was determined based on the fair value of the reclassified equity awards at the date of the modification using a binomial-lattice pricing model.

Baytex's Share Award Incentive Plan is described in note 17.

4. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Financial Instruments

IASB published IFRS 9, "Financial Instruments" and replaces IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: at amortized cost or fair value.

IFRS 9 is effective for annual periods beginning on or after January 1, 2015, with earlier application permitted. The adoption of this standard may have an impact on the Company's accounting for financial assets and financial liabilities.

Consolidation, Joint Ventures and Disclosures

In May 2011, the IASB issued new standards, IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements" and IFRS 12, "Disclosure of Interests in Other Entities". IAS 27, "Separate Financial Statements" and IAS 28, "Investments in Associates and Joint Ventures" were amended based on the issuance of IFRS 10, IFRS 11 and IFRS 12. Each of the new and revised standards is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The adoption of these standards may have an impact on the consolidated financial statements of the Company.

Consolidated Financial Statements

IFRS 10, "Consolidated Financial Statements" replaces the consolidation guidance in IAS 27, "Consolidated and Separate Financial Statements" by introducing a single consolidation model for all entities based on control, irrespective of the nature of the investee. Under IFRS 10, control is based on whether an investor has 1) power over the investee; 2) exposure, or rights, to variable returns from its involvement with the investee; and 3) the ability to use its power over the investee to affect the amount of the returns.

Joint Arrangements

IFRS 11, "Joint Arrangements" replaces IAS 31, "Interest in Joint Ventures". The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted.

Disclosure of Interests in Other Entities

IFRS 12, "Disclosure of Interests in Other Entities", requires enhanced disclosures about both consolidated entities and unconsolidated entities in which an entity has involvement. The objective of IFRS 12 is to require information so that financial statement users may evaluate the basis of control, any restrictions on consolidated assets and liabilities, risk exposures arising from involvements with unconsolidated structured entities and non-controlling interest holders' involvement in the activities of consolidated entities.

Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "Fair Value Measurement" which replaces the guidance on fair value measurement in existing IFRS accounting literature with a single standard. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 with early application permitted. The adoption of this standard may have an impact on the consolidated financial statements of the Company.

Presentation of Financial Statements

In June 2011, the IASB amended IAS 1, "Presentation of Financial Statements" to require companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income that may be reclassified to the net income section of the income statement. The amendments also reaffirm existing requirements that items in other comprehensive income and profit or loss should be presented as either a single statement or two consecutive statements. The amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the consolidated financial statements of the Company.

5. BUSINESS COMBINATIONS

2011 Corporate Acquisition

On February 3, 2011, Baytex acquired all the issued and outstanding shares of a private company, which was a junior heavy oil producer with operational focus in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan, for total consideration of $120.9 million (net of cash acquired). This acquisition provides additional development opportunities in the Seal area where Baytex already possesses significant leasehold and operating infrastructure. The acquisition has been accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:		
Cash paid for exploration and evaluation assets and oil and gas properties	$	120,006
Cash paid for working capital (net of cash acquired)		869
Total consideration	$	120,875
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Trade and other receivables	$	1,664
Exploration and evaluation assets		14,944
Oil and gas properties		131,635
Trade and other payables		(795)
Asset retirement obligations		(2,031)
Deferred income tax liability		(24,542)
Total net assets acquired	$	120,875

Acquisition-related costs totaling $0.3 million have been excluded from the consideration transferred and have been recognized as an expense in the year ended December 31, 2011, within the "general and administrative" line item in the consolidated statements of income and comprehensive income. The fair value of the acquired trade and other receivables approximates the carrying value due to their short term nature.

From the period of February 3, 2011 to December 31, 2011, the acquired properties contributed revenues, net of royalties, of $38.3 million and revenues, net of royalties, production and operating expenses ("operating income") of $25.5 million to Baytex's operations. If the acquisition had occurred on January 1, 2011, management estimates its pro forma revenues, net of royalties and operating income would have been approximately $41.4 million and $27.9 million, respectively, for the year ended December 31, 2011. It is impracticable to derive all amounts necessary to determine contributed net income from the acquired properties as operations were immediately merged with Baytex's operations to realize synergies.

The fair values of assets and liabilities recognized are estimates due to the uncertainty of provisional amounts recognized.

2011 Property Acquisition

On February 3, 2011, Baytex acquired heavy oil properties in the Seal area of northern Alberta and the Lloydminster area of western Saskatchewan, for total consideration of $38.4 million. This acquisition provides additional development opportunities in the Seal area where Baytex already possesses significant leasehold and operating infrastructure. The acquisition has been accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:		
Cash paid	$	38,439
Total consideration	$	38,439
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Exploration and evaluation assets	$	1,700
Oil and gas properties		37,247
Asset retirement obligations		(508)
Total net assets acquired	$	38,439

Acquisition-related costs totaling $0.1 million have been excluded from the consideration transferred and have been recognized as an expense in the year ended December 31, 2011, within the "General and administrative" line item in the consolidated statements of income and comprehensive income.

From the period of February 3, 2011 to December 31, 2011, the acquired properties contributed revenues, net of royalties, of $9.6 million and operating income of $6.4 million to Baytex's operations. If the acquisition had occurred on January 1, 2011, management estimates its pro forma revenues, net of royalties and operating income would have been approximately $10.4 million and $7.0 million, respectively, for the year ended December 31, 2011. It is impracticable to derive all amounts necessary to determine contributed net income from the acquired properties as operations were immediately merged with Baytex's operations to realize synergies.

The fair values of assets and liabilities recognized are estimates due to the uncertainty of provisional amounts recognized.

2010 Corporate Acquisition

On May 26, 2010, Baytex acquired all the issued and outstanding shares of a private company, which was a junior heavy oil producer with operational focus in east central Alberta through to west central Saskatchewan, for total consideration of $40.3 million (net of cash acquired). The acquired assets provide a number of cold heavy oil development opportunities and were readily integrated into Baytex's existing producing infrastructure in the Lloydminster area. The acquisition has been accounted for as a business combination with the fair value of the assets acquired and liabilities assumed at the date of acquisition summarized below:

Consideration for the acquisition:		
Cash paid (net of cash acquired)	$	40,314
Total consideration	$	40,314
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Trade and other receivables	$	1,722
Exploration and evaluation assets		2,534
Oil and gas properties		48,313
Trade and other payables		(1,436)
Asset retirement obligations		(2,207)
Deferred income tax liability		(8,612)
Total net assets acquired	$	40,314

Acquisition-related costs totaling $0.6 million have been excluded from the consideration transferred and have been recognized as an expense in the year ended December 31, 2010, within the "general and administrative" line item in the consolidated statements of income and comprehensive income. The fair value of the acquired trade and other receivables approximates the carrying value due to their short term nature.

From the period of May 26, 2010 to December 31, 2010, the acquired properties contributed revenues, net of royalties, of $8.7 million and operating income of $3.9 million to Baytex's operations. If the acquisition had occurred on January 1, 2010, management estimates its pro forma revenues, net of royalties and operating income would have been approximately $14.9 million and $3.6 million, respectively, for the year ended December 31, 2010. It is impracticable to derive all amounts necessary to determine contributed net income from the acquired properties as operations were immediately merged with Baytex's operations to realize synergies.

6. TRADE AND OTHER RECEIVABLES

As at		December 31, 2011		December 31, 2010		January 1, 2010
Petroleum and natural gas sales and accrual	$	161,567	$	119,827	$	107,657
Joint venture		42,928		30,536		28,581
Prepaid, deposits and other		3,415		3,282		3,252
Allowance for doubtful accounts		(959)		(1,853)		(2,336)

	$	206,951	$	151,792	$	137,154

7. EXPLORATION AND EVALUATION ASSETS

Cost

As at January 1, 2010	$	124,621
Capital expenditures		37,411
Corporate acquisition		2,534
Exploration and evaluation expense		(18,913)
Transfer to oil and gas properties		(29,116)
Divestitures		(113)
Foreign currency translation		(3,342)
As at December 31, 2010	$	113,082
Capital expenditures		9,104
Corporate acquisition		14,944
Property acquisition		18,013
Exploration and evaluation expense		(10,130)
Transfer to oil and gas properties		(14,398)
Divestitures		(2,058)
Foreign currency translation		1,217
As at December 31, 2011	$	129,774

8. OIL AND GAS PROPERTIES

Cost

As at January 1, 2010	$	1,512,035
Capital expenditures		218,651
Corporate acquisition		48,313
Transferred from exploration and evaluation assets		29,116
Change in asset retirement obligations		21,766
Divestitures		(4,072)
Foreign currency translation		(6,458)
As at December 31, 2010	$	1,819,351
Capital expenditures		364,578
Corporate acquisition		131,635
Property acquisitions		61,137
Transferred from exploration and evaluation assets		14,398
Change in asset retirement obligations		84,879
Divestitures		(10,233)
Foreign currency translation		5,674
As at December 31, 2011	$	2,471,419

Accumulated depletion

As at January 1, 2010	$	–
Depletion for the period		195,015
Divestitures		(107)
Foreign currency translation		(186)
As at December 31, 2010	$	194,722

Depletion for the period		244,893
Divestitures		(667)
Foreign currency translation		311
As at December 31, 2011	$	439,259

Carrying value

As at January 1, 2010	$	1,512,035
As at December 31, 2010	$	1,624,629
As at December 31, 2011	$	2,032,160

For the year ended December 31, 2011, Baytex disposed of assets in Kaybob and Dodsland areas which consisted of $9.0 million of oil and gas properties and $2.1 million of exploration and evaluation assets for net cash proceeds of $47.4 million. Gains totaling $36.3 million were recognized in the statements of income and comprehensive income.

The carrying value of petroleum and natural gas properties are subject to impairment tests, which were calculated at December 31, 2011 using the following benchmark reference prices for the years 2012 to 2016 adjusted for commodity differentials specific to the Company:

	2012	2013	2014	2015	2016
WTI crude oil (US$/bbl)	98.07	94.90	92.00	97.42	99.37
AECO natural gas ($/MMBtu)	3.16	3.78	4.13	5.53	5.65
Exchange rate (USD/CAD)	1.01	1.01	1.01	1.01	1.01

Oil and natural gas prices reflect the NYMEX futures market for the period ending 2012. This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2016 have been adjusted for estimated inflation at an estimated annual rate of 2 percent. Based on the impairment test calculations, the Company's estimated discounted future net cash flows associated with proved and probable reserves exceeded the net book value of the oil and gas properties.

9. OTHER PLANT AND EQUIPMENT

Cost		
As at January 1, 2010	$	49,341
Capital expenditures		8,473
Disposals		(236)
Foreign currency translation		(54)
As at December 31, 2010	$	57,524
Capital expenditures		1,252
Foreign currency translation		25
As at December 31, 2011	$	58,801

Accumulated depletion		
As at January 1, 2010	$	22,245
Depreciation		7,781
Disposals		(26)
Foreign currency translation		(26)
As at December 31, 2010	$	29,974
Depreciation		3,575
Foreign currency translation		19
As at December 31, 2011	$	33,568

Carrying value		
As at January 1, 2010	$	27,096
As at December 31, 2010	$	27,550
As at December 31, 2011	$	25,233

Field inventory held is valued at the lower of cost, using the weighted average cost method, or net realizable value and is not depreciated.

10. GOODWILL

As at	December 31, 2011	December 31, 2010	January 1, 2010
Cost	$ 37,755	$ 37,755	$ 37,755
Impairment	–	–	–
Carrying value	$ 37,755	$ 37,755	$ 37,755

The carrying value, calculated based on the higher of value-in-use (as compared to fair value less cost to sell), of the CGU was determined to be lower than its recoverable amount and no impairment loss was recognized.

The Company estimates value-in-use by using a discounted cash flow model using a pre-tax discount rate. The reserve reports generated by an external party and approved by senior management on an annual basis is the source for information for the determination of the value-in-use value assigned. The reserve reports are based on a remaining reserve life of 50 years. The forecasted cash flows include reserves where there is at least a 50% probability that the estimated proved plus probable reserves will be recovered. Value-in-use, related to this goodwill impairment test, was determined by discounting the future cash flows generated from the CGU using key assumptions as noted in note 8 "Oil and Gas Properties".

11. BANK LOAN

As at	December 31, 2011	December 31, 2010	January 1, 2010
Bank loan	$ 311,960	$ 303,773	$ 265,088

Baytex Energy Ltd. ("Baytex Energy"), a wholly-owned subsidiary of Baytex, has established credit facilities with a syndicate of chartered banks. On June 14, 2011, Baytex Energy reached agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the facilities to $700 million (from $650 million), (ii) extend the revolving period from 364 days (with a one-year term out following the revolving period) to three years, which is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time), and (iii) change the structure of the facilities from reserves-based to covenant-based (with standard commercial covenants for facilities of this nature). The credit facilities do not require any mandatory principal payments during the three-year term. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain of its material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with covenants under the credit facilities, Baytex's ability to pay dividends to its shareholders may be restricted.

Financing costs for the year ended December 31, 2011 includes facility amendment fees of $2.3 million ($1.4 million for year ended December 31, 2010). The weighted average interest rate on the bank loan for the year ended December 31, 2011 was 3.69% (3.94% for the year ended December 31, 2010).

12. TRADE AND OTHER PAYABLES

As at		December 31, 2011		December 31, 2010		January 1, 2010
Trade payables	$	120,717	$	79,841	$	79,150
Joint venture		17,457		12,284		14,924
Capital and operating expense accruals		74,673		77,656		75,471
Other		12,984		13,533		16,971
	$	225,831	$	183,314	$	186,516

13. LONG-TERM DEBT

As at		December 31, 2011		December 31, 2010		January 1, 2010
9.15% senior unsecured debentures (Cdn$150,000 – principal)	$	147,328	$	146,893	$	146,498
6.75% senior unsecured debentures (US$150,000 – principal)		150,403		–		–
	$	297,731	$	146,893	$	146,498

On August 26, 2009, the Trust issued $150.0 million principal amount of Series A senior unsecured debentures bearing interest at 9.15% payable semi-annually with principal repayable on August 26, 2016. As a result of the Arrangement, Baytex assumed all of the rights and obligations of the Trust under the Series A senior unsecured debentures effective January 1, 2011. These debentures are subordinate to Baytex Energy's bank credit facilities. After August 26 of each of the following years, these debentures are redeemable at the Company's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2012 at 104.575%, 2013 at 103.05%, 2014 at 101.525% and 2015 at 100%. These notes are carried at amortized cost, net of a $3.6 million transaction cost. The notes accrete up to the principal balance at maturity using the effective interest rate of 9.6%.

On February 17, 2011, Baytex issued US$150.0 million principal amount of Series B senior unsecured debentures bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These debentures are subordinate to Baytex Energy's bank credit facilities. After February 17 of each of the following years, these debentures are redeemable at the Company's option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the debentures): 2016 at 103.375%, 2017 at 102.25%, 2018 at 101.525% and 2019 at 100%. These notes are carried at amortized cost, net of a $2.2 million transaction cost. These notes accrete up to the principal balance at maturity using the effective interest rate of 7.0%.

Accretion expense on debentures of $0.2 million has been recorded for the year ended December 31, 2011 (year ended December 31, 2010 – $0.3 million).

14. CONVERTIBLE DEBENTURES

	Number of Convertible Debentures	Convertible Debentures	Conversion Feature of Debentures
Balance, January 1, 2010	7,815	$ 7,736	$ 7,354
Conversion	(7,474)	(7,426)	(12,473)
Accretion	–	31	–
Loss on financial derivative	–	–	5,119
Repayment on maturity	(341)	(341)	–
Balance, December 31, 2010 and December 31, 2011	–	$ –	$ –

In June 2005, the Trust issued $100.0 million principal amount of 6.5% convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures paid interest semi-annually and were convertible at the option of the holder at any time into fully-paid trust units at a conversion price of $14.75 per trust unit. On the December 31, 2010 maturity date, the outstanding $0.3 million principal amount was repaid at par value.

The debentures were classified as debt net of the fair value of the conversion feature which was classified as a financial derivative liability. This resulted in $95.2 million being classified as debt and $4.8 million being initially classified as a financial derivative liability. The debt portion accreted up to the principal balance at maturity, using the effective interest rate of 7.6%. The accretion and the interest paid were expensed as a finance expense in the consolidated statements of income and comprehensive income. When debentures were converted to trust units, the fair value of the conversion feature under financial derivative liability was reclassified to unitholders' capital along with the principal amounts converted.

15. ASSET RETIREMENT OBLIGATIONS

	December 31, 2011	December 31, 2010
Balance, beginning of year	$ 169,611	$ 141,869
Liabilities incurred	5,834	2,030
Liabilities settled	(10,588)	(2,829)
Liabilities acquired	5,003	2,207
Liabilities divested	(556)	(1,254)
Accretion	6,185	5,862
Change in estimate[(1)]	84,879	21,766
Foreign currency translation	43	(40)
Balance, end of year	$ 260,411	$ 169,611

(1) Changes in the status of wells, changes in discount rates and changes in the estimated costs of abandonment and reclamation are factors resulting in a change in estimate.

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years. The undiscounted amount of estimated cash flow required to settle the asset retirement obligations using an estimated annual inflation rate of 2.0% at December 31, 2011 is $315.9 million (December 31, 2010 – $288.8 million, January 1, 2010 – $279.3 million). The amount of estimated cash flow required to settle the asset retirement obligations using an estimated annual inflation rate of 2.0% and discounted at a risk free rate of 2.5% at December 31, 2011 (December 31, 2010 – 3.5% and January 1, 2010 – 4.0%) is $260.4 million (December 31, 2010 – $169.6 million and January 1, 2010 – $141.9 million).

16. SHAREHOLDERS'/UNITHOLDERS' CAPITAL

Unitholders' Capital

	Number of Trust Units		Amount
Balance, January 1, 2010	109,299	$	1,331,161
Issued on conversion of debentures	507		19,897
Issued on exercise of unit rights	2,337		26,021
Transfer from unit-based payment liability on exercise of unit rights	–		56,628
Issued pursuant to distribution reinvestment plan	1,569		51,699
Change in effective tax rate on issue costs	–		(1,071)
Exchanged for shares, pursuant to the Arrangement	(113,712)		(1,484,335)
Balance, December 31, 2010 and December 31, 2011	–	$	–

Shareholders' Capital

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2011, no preferred shares have been issued by the Company and all common shares issued were fully paid.

	Number of Common Shares		Amount
Balance, January 1, 2010	–	$	–
Issued for units, pursuant to the Arrangement	113,712		1,484,335
Balance, December 31, 2010	113,712	$	1,484,335
Issued on exercise of share rights	2,665		45,048
Transfer from contributed surplus on exercise of share rights	–		77,258
Issued pursuant to dividend reinvestment plan	1,516		73,543
Balance, December 31, 2011	117,893	$	1,680,184

Baytex has a Dividend Reinvestment Plan (the "DRIP") that allows eligible holders in Canada and the United States to reinvest their monthly cash dividends to acquire additional common shares. At the discretion of Baytex, common shares will either be issued from treasury or acquired in the open market at prevailing market prices. Pursuant to the terms of the DRIP, common shares were issued from treasury at a five percent discount to the arithmetic average of the daily volume weighted average trading prices of the common shares on the Toronto Stock Exchange (in respect of participants resident in Canada or any jurisdiction other than the United States) or the New York Stock Exchange (in respect of participants resident in the United States) for the period commencing on the second business day after the dividend record date and ending on the second business day immediately prior to the dividend payment date. Commencing with the dividends declared on December 15, 2011, the discount was reduced to three percent. Baytex reserves the right at any time to change or eliminate the discount on common shares acquired through the DRIP from treasury.

The holders of common shares or trust units may receive dividends or distributions as declared from time to time and are entitled to one vote per share or trust unit at any meetings of the holders of common shares or trust units. All common shares rank among themselves equally and with regard to the Company's net assets in the event of termination or winding-up of the Company.

Monthly dividends of $0.22 per common share in December 2011 and $0.20 per month for each of the previous eleven months were declared by the Company during the year ended December 31, 2011 for total dividends declared of $281.0 million. Monthly distributions of $0.20 per trust unit in December 2010 and $0.18 per trust unit for each of the previous eleven months were declared by the Trust during the year ended December 31, 2010 for total distributions declared of $243.4 million.

Subsequent to December 31, 2011, the Company announced that monthly dividends in respect of January and February 2012 operations of $0.22 per common share totaling $26.1 million each month will be payable on February 15, 2012 and March 15, 2012 to shareholders of record at January 31, 2012 and February 29, 2012, respectively.

17. EQUITY BASED PLANS

Share Rights Plan

The Trust had a Unit Rights Plan pursuant to which rights to acquire trust units ("unit rights") were granted to eligible directors, officers and employees of the Trust and its subsidiaries. The maximum number of trust units issuable pursuant to the Unit Rights Plan was a "rolling" maximum equal to 10% of the outstanding trust units plus the number of trust units which were issuable on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding trust units resulted in an increase in the number of trust units available for issuance under the Unit Rights Plan, and any exercises of unit rights made new grants available under the Unit Rights Plan, effectively resulting in a re-loading of the number of unit rights available to grant under the Unit Rights Plan. Under the Unit Rights Plan, unit rights had a maximum term of five years and vested and became exercisable as to one-third on each of the first, second and third anniversaries of the grant date.

The Unit Rights Plan provided that the exercise price of the unit rights may be reduced to account for future distributions, subject to certain performance criteria. Effective November 16, 2009, the Unit Rights Plan was amended to (i) base the exercise price of unit rights on the closing price of the trust units on the trading day prior to the date of grant (previously based on a five-day volume weighted average trading price) and (ii) permit the granting of unit rights with a fixed exercise price. Effective October 25, 2010, the Unit Rights Plan was amended to provide holders of unit rights who are not subject to taxation in the United States with the ability to elect at the time of exercise to pay an exercise price per unit right equal to (i) the original exercise price reduced for distributions paid subsequent to grant date or (ii) the original exercise price.

Pursuant to the terms of the Unit Rights Plan, the Arrangement (as described in note 1) constituted a capital reorganization which resulted in each holder of unit rights exchanging such rights for equivalent rights to acquire common shares of Baytex ("share rights") on a one-for-one basis on December 31, 2010. The share rights are subject to the terms of the Share Rights Plan. The Share Rights Plan is substantially similar to the Unit Rights Plan other than amendments necessary to reflect:

- The entitlement of holders to receive common shares instead of trust units;
- The exercise price, as calculated for unit rights outstanding at the effective time of the Arrangement, will be carried forward under the Share Rights Plan and, if applicable, future adjustments to the exercise price after the completion of the Arrangement will be based on dividends paid on the common shares of Baytex rather than distributions paid on the trust units of the Trust; and
- The administration of the Share Rights Plan will be carried out by Baytex as opposed to Baytex Energy.

As a result of the adoption of the Share Award Incentive Plan (as described below), no further grants will be made under the Share Rights Plan effective January 1, 2011.

Baytex recorded compensation expense of $15.6 million for the year ended December 31, 2011 (year ended December 31, 2010 – $94.2 million) related to the share rights under the Share Rights Plan or the unit rights under the Unit Rights Plan.

Baytex used a binomial-lattice pricing model to calculate the estimated weighted average fair value of the share rights and unit rights. The following assumptions were used to arrive at the estimate of fair values at each reporting date, with the expense recognized from the December 31, 2010 date of modification over the remainder of the vesting period determined based on the fair value of the reclassified unit rights at the date of the modification:

As at	December 31, 2010	January 1, 2010
Expected annual exercise price reduction (on unit rights or share rights with declining exercise price)	Various	$ 2.16
Share or unit price	$ 46.61	$ 29.70
Expected volatility[(1)]	43.8%	43.4%
Risk free interest rate	1.99%	2.57%
Forfeiture rate	4.6%	4.6%

(1) Expected volatility is estimated by considering the historical average price volatility of the common shares/trust units commensurate with the term of the right.

The number of share rights or unit rights outstanding and exercise prices are detailed below:

	Number of share or unit rights (000's)	Weighted average exercise price
Balance, January 1, 2010	8,120	$ 16.68
Granted[(2)]	190	32.71
Exercised[(1)]	(2,337)	11.13
Forfeited[(1)]	(212)	20.35
Balance, December 31, 2010	5,761	$ 17.02
Granted	–	–
Exercised[(1)]	(2,665)	16.92
Forfeited[(1)]	(125)	23.05
Balance, December 31, 2011	2,971	$ 16.98

(1) Weighted average exercise price reflects the grant price less the reduction in exercise price.
(2) Weighted average exercise price of rights granted is based on the exercise price at the date of grant.

The following table summarizes information about the share rights outstanding at December 31, 2011:

	Exercise Prices Applying Original Grant Price					Exercise Prices Applying Original Grant Price Reduced for Dividends and Distributions Subsequent to Grant Date				
PRICE RANGE	Number Outstanding at December 31, 2011 (000's)	Weighted Average Grant Price	Weighted Average Remaining Term (years)	Number Exercisable at December 31, 2011 (000's)	Weighted Average Exercise Price	Number Outstanding at December 31, 2011 (000's)	Weighted Average Exercise Price	Weighted Average Remaining Term (years)	Number Exercisable at December 31, 2011 (000's)	Weighted Average Exercise Price
$5.08 to $12.00	–	$ –	–	–	$ –	1,385	$10.88	1.5	1,305	$10.97
$12.01 to $19.00	1,174	17.63	1.8	1,067	17.85	369	17.01	2.1	285	17.28
$19.01 to $26.00	648	20.23	1.2	584	20.01	1,014	22.85	2.8	616	22.85
$26.01 to $33.00	1,105	27.94	2.9	648	27.79	177	28.45	3.1	96	27.94
$33.01 to $40.00	41	35.60	3.6	7	35.35	24	34.78	3.6	4	35.29
$40.01 to $47.72	3	44.96	4.0	1	44.35	2	43.29	4.0	1	42.63
$5.08 to $47.72	2,971	$22.30	2.1	2,307	$21.25	2,971	$16.98	2.1	2,307	$15.60

Share Award Incentive Plan

In connection with the Arrangement, the unitholders of the Trust approved, at a special meeting held on December 9, 2010, the adoption by the Company effective January 1, 2011 of a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plan of the

Company, including the Share Rights Plan) shall not at any time exceed 10% of the then issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents as described below) with such common shares to be issued as to one-third on each of the first, second and third anniversary dates of the date of grant. Each performance award entitles the holder to be issued as to one-third on each of the first, second and third anniversary dates of the date of grant the number of common shares designated in the performance award (plus dividend equivalents as described below) multiplied by a payout multiplier. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payment of dividends from the grant date to the applicable issue date.

The Company recorded compensation expense of $18.2 million for the year ended December 31, 2011 and related to the share awards (year ended December 31, 2010 – $nil).

The fair value of share awards is determined at the date of grant using the closing price of the common shares and, for performance awards, an estimated payout multiplier. The amount of compensation expense is reduced by an estimated forfeiture rate, which has been estimated at 4.6% of outstanding awards. Fluctuations in compensation expense may occur due to changes in estimating the outcome of the performance conditions. The estimated weighted average fair value for share awards is $50.27 per restricted award and performance award granted during the year ended December 31, 2011 (no share awards were granted during the year ended December 31, 2010).

The number of share awards outstanding is detailed below:

	Number of restricted awards (000's)	Number of performance awards (000's)	Number of share awards (000's)
Balance, January 1, 2010 and December 31, 2010	–	–	–
Granted	389	243	632
Forfeited	(24)	(14)	(38)
Balance, December 31, 2011	365	229	594

Under the terms of the Share Award Incentive Plan, the Compensation Committee of the Board of Directors of Baytex has the authority to approve the granting of share awards. The Compensation Committee's historical practice is to split the share award into two equal amounts, with 50% granted immediately and 50% granted six months subsequent to the initial grant date (with such grant being conditional on the grantee continuing to be employed by the Company or its subsidiaries on such date).

18. NET INCOME PER SHARE AND PER TRUST UNIT

Baytex calculates basic income per share and per trust unit based on the net income attributable to shareholders or unitholders and a weighted average number of shares or units outstanding during the period. Diluted income per share or trust unit amounts reflect the potential dilution that could occur if share rights or unit rights were exercised, share awards were converted and convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of share rights or unit rights whereby any proceeds from the exercise of share rights or unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services not yet recognized are assumed to be used to purchase common shares or trust units at the average market price during the periods.

	Years Ended December 31								
	2011				2010				
		Net income	Common shares (000's)		Net income per share		Net income	Trust units (000's)		Net income per unit
Net income – basic	$	217,432	115,960	$	1.88	$	231,615	111,450	$	2.08
Dilutive effect of share rights or unit rights		–	2,643				–	3,304		
Dilutive effect of share awards		–	318				–	–		
Conversion of convertible debentures		–	–				297	397		
Net income – diluted	$	217,432	118,921	$	1.83	$	231,912	115,151	$	2.01

For the year ended December 31, 2011, nil share rights (year ended December 31, 2010 – 0.1 million unit rights) were excluded in calculating the weighted average number of diluted common shares outstanding as they were anti-dilutive.

19. INCOME TAXES

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

	Years Ended December 31			
		2011		2010
Net income before income taxes	$	269,573	$	107,375
Expected income taxes at the statutory rate of 26.95% (2010 – 28.49%)[(1)]		72,650		30,591
Increase (decrease) in income taxes resulting from:				
Net income of the Trust prior to the Arrangement		–		(69,342)
Non-taxable portion of foreign exchange loss (gain)		1,580		(1,333)
Non-deductible (taxable) items		–		(2,854)
Share-based or unit-based compensation		9,120		26,838
Effect of change in income tax rates		(9,902)		11,132
Effect of rate adjustments for foreign jurisdictions		(3,464)		(3,730)
Effect of change in opening tax pool balances		(14,740)		(5,740)
Effect of change in valuation allowance		(1,770)		–
Deferred credit[(2)]		–		(109,800)
Other		(1,333)		(2)
Deferred income tax expense (recovery)	$	52,141	$	(124,240)

(1) *The change in statutory rate is related to a legislated reduction in the Canadian Federal corporate income tax rate and changes in the provincial apportionment of income.*

(2) *In May 2010, Baytex acquired a number of private entities for use in its internal financing structure for approximately $38.0 million. The transaction resulted in the recognition of a future income tax asset of approximately $147.8 million with a corresponding deferred credit of $109.8 million recognized under previous GAAP, reflecting the difference between the future income tax asset recognized on the transaction and the cash paid. Under IFRS, the deferred credit is derecognized through net income as a deferred income tax recovery.*

The components of the net deferred income tax liability are as follows:

As at	December 31, 2011	December 31, 2010	January 1, 2010
Deferred income tax liabilities:			
Petroleum and natural gas properties	$ (280,118)	$ (224,923)	$ (196,118)
Financial derivatives	–	(4,463)	(9,432)
Partnership deferral	(86,019)	(52,327)	(2,921)
Other	(2,700)	(5,025)	(3,875)
Deferred income tax assets:			
Asset retirement obligations	55,038	43,339	36,446
Financial derivatives	7,362	7,870	1,789
Non-capital losses	219,874	227,149	13,185
Finance costs	3,479	1,867	1,996
Net deferred income tax liability(1)(2)	$ (83,084)	$ (6,513)	$ (158,930)

(1) Non-capital loss carry-forwards totaled $803.1 million (December 31, 2010 – $842.3 million, January 1, 2010 – $48.4 million) and expire from 2014 to 2031.

(2) Baytex has recognized a net deferred tax asset of $10.3M relating to its US subsidiary. The Company has reviewed the reserves report, undeveloped land holdings and budget forecasts for this subsidiary and has determined that it is probable that future taxable profits will be sufficient to utilize the deductible temporary differences.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2010	Recognized in Net Income	Acquired in Business Combination	Other	December 31, 2010
Deferred income tax liabilities:					
Petroleum and natural gas properties	$ (196,118)	$ (19,641)	$ (9,164)	$ –	$ (224,923)
Financial derivatives	(9,432)	4,969	–	–	(4,463)
Partnership deferral	(2,921)	(49,406)	–	–	(52,327)
Other	(3,875)	(1,009)	–	(141)	(5,025)
Deferred income tax assets:					
Asset retirement obligations	36,446	6,341	552	–	43,339
Financial derivatives	1,789	6,081	–	–	7,870
Non-capital losses	13,185	175,964	38,000	–	227,149
Finance costs	1,996	941	–	(1,070)	1,867
Net deferred income tax liability	$ (158,930)	$ 124,240	$ 29,388	$ (1,211)	$ (6,513)

As at	January 1, 2011	Recognized in Net Income	Acquired in Business Combination	Other	December 31, 2011
Deferred income tax liabilities:					
Petroleum and natural gas properties	$ (224,923)	$ (25,724)	$ (25,059)	$ –	$ (275,706)
Financial derivatives	(4,463)	4,463	–	–	–
Partnership deferral	(52,327)	(33,692)	–	–	(86,019)
Other	(5,025)	2,213	–	112	(2,700)
Deferred income tax assets:					
Asset retirement obligations	43,339	11,182	517	–	55,038
Financial derivatives	7,870	(508)	–	–	7,362

Non-capital losses		227,149	(11,687)	–	–		215,462
Finance costs		1,867	1,612	–	–		3,479
Net deferred income tax liability	$	(6,513) $	(52,141) $	(24,542) $	112	$	(83,084)

20. REVENUES

	Years Ended December 31	
	2011	2010
Petroleum and natural gas revenues	$ 1,305,814	$ 1,003,295
Royalty charges	(212,172)	(170,844)
Royalty income	3,000	1,841
Revenues, net of royalties	$ 1,096,642	$ 834,292

21. FINANCING COSTS

Baytex incurred financing costs on its outstanding liabilities as follows:

	Years Ended December 31	
	2011	2010
Bank loan and other	$ 12,489	$ 12,547
Long-term debt	22,935	14,198
Accretion on asset retirement obligations	6,185	5,862
Convertible debentures	–	320
Debt financing costs	3,002	1,643
Financing costs	$ 44,611	$ 34,570

22. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Years Ended December 31	
	2011	2010
Trade and other receivables	$ (55,159)	$ (14,638)
Crude oil inventory	905	(418)
Trade and other payables	40,992	(2,678)
Foreign exchange	(180)	74
	$ (13,442)	$ (17,660)
Changes in non-cash working capital related to:		
Operating activities	$ (10,889)	$ (11,704)
Investing activities	(2,553)	(5,956)
	$ (13,442)	$ (17,660)

Foreign Exchange

	Years Ended December 31	
	2011	2010
Unrealized foreign exchange loss (gain)	$ 8,490	$ (8,999)
Realized foreign exchange gain	(656)	(149)

Foreign exchange loss (gain)	$	7,834	$	(9,148)

Income Statement Presentation

The following table details the amount of total employee compensation costs included in the production and operating expense and general and administrative expense.

	Years Ended December 31	
	2011	2010
Production and operating	$ 6,457	$ 5,675
General and administrative	25,529	24,400
Total employee compensation costs	$ 31,986	$ 30,075

23. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, dividends or distributions payable to shareholders or unitholders, bank loan, financial derivatives, long-term debt and convertible debentures.

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. 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 loan and long-term debt, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of the bank loan approximates its carrying value as it is at a market rate of interest. The fair value of the long-term debt is based on the trading value of the debentures.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	December 31, 2011		December 31, 2010		January 1, 2010		
As at	Carrying Value	Fair Value	Carrying Value	Fair Value	Carrying Value	Fair Value	Fair Value Measurement Hierarchy
Financial Assets							
FVTPL							
Cash	$ 7,847	$ 7,847	$ –	$ –	$ 10,177	$ 10,177	Level 1
Derivatives	11,059	11,059	16,543	16,543	31,994	31,994	Level 2
Total FVTPL	$ 18,906	$ 18,906	$ 16,543	$ 16,543	$ 42,171	$ 42,171	
Loans and receivables							
Trade and other receivables	$ 206,951	$ 206,951	$ 151,792	$ 151,792	$ 137,154	$ 137,154	–
Total loans and receivables	$ 206,951	$ 206,951	$ 151,792	$ 151,792	$ 137,154	$ 137,154	
Financial Liabilities							
FVTPL							
Derivatives	$ (39,990)	$ (39,990)	$ (29,171)	$ (29,171)	$ (13,422)	$ (13,422)	Level 2
Total FVTPL	$ (39,990)	$ (39,990)	$ (29,171)	$ (29,171)	$ (13,422)	$ (13,422)	
Other financial liabilities							
Trade and other payables	$ (225,831)	$ (225,831)	$ (183,314)	$ (183,314)	$ (186,516)	$ (186,516)	–
Dividends or distributions payable to shareholders / unitholders	(25,936)	(25,936)	(22,742)	(22,742)	(19,674)	(19,674)	–
Bank loan	(311,960)	(311,960)	(303,773)	(303,773)	(265,088)	(265,088)	–
Convertible debentures	–	–	–	–	(7,736)	(7,736)	–
Long-term debt	(297,731)	(314,201)	(146,893)	(163,875)	(146,498)	(162,750)	–
Total other financial liabilities	$ (861,458)	$ (877,928)	$ (656,722)	$ (673,704)	$ (625,512)	$ (641,764)	

There were no transfers between Level 1 and 2 in the period.

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign currency risk

Baytex is exposed to fluctuations in foreign currency as a result of the U.S. dollar portion of its bank loan, its Series B senior unsecured debentures, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The Company's net income and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of currency exchange rate fluctuations, the Company may enter into agreements to fix the Canada–U.S. exchange rate.

At December 31, 2011, the Company had in place the following currency derivative contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly forward spot sale	June 2010 to June 2012	US$1.00 million	1.0250	(1)
Monthly forward spot sale	January 2011 to June 2012	US$3.00 million	1.0622	(1)
Monthly forward spot sale	January 2011 to August 2012	US$1.00 million	1.0565	(1)
Monthly forward spot sale	January 2011 to September 2012	US$1.50 million	1.0553	(1)
Monthly forward spot sale	November 2011 to October 2013	US$1.00 million	1.0433	(1)
Monthly forward spot sale	Calendar 2012	US$6.25 million	1.0084	(2)
Monthly average rate forward	Calendar 2012	US$1.25 million	1.0209	(2)
Monthly spot collar	Calendar 2012	US$0.75 million	0.9524 - 1.0503	(1)
Monthly spot collar	Calendar 2012	US$0.25 million	1.0200 - 1.0700	(1)
Monthly average collar	Calendar 2012	US$0.25 million	0.9700 - 1.0310	(1)
Monthly average collar	Calendar 2012	US$0.50 million	0.9750 - 1.0305	(1)
Monthly average collar	Calendar 2012	US$0.75 million	1.0225 - 1.0425	(1)
Monthly average collar	Calendar 2012	US$0.25 million	1.0295 - 1.0545	(1)
Monthly forward spot sale	Calendar 2013	US$4.50 million	1.0007	(2)
Monthly average rate forward	Calendar 2013	US$0.25 million	1.0023	(1)
Monthly average collar	Calendar 2013	US$0.25 million	0.9700 - 1.0310	(1)

(1) Actual contract rate (CAD/USD).
(2) Based on the weighted average contract rates (CAD/USD).

The following table demonstrates the effect of movements in the Canadian – United States exchange rate on net income before income taxes and comprehensive income due to changes in the fair value of the currency swaps as well as gains and losses on the revaluation of U.S. dollar denominated monetary assets and liabilities at December 31, 2011.

		$0.01 Increase (Decrease) in CAD/USD Exchange Rate
Loss (gain) on currency derivative contracts	$	1,648
Loss (gain) on other monetary assets/liabilities		2,954
Impact on net income before income taxes and comprehensive income	$	4,602

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets			Liabilities		
	December 31, 2011	December 31, 2010	January 1, 2010	December 31, 2011	December 31, 2010	January 1, 2010
U.S. dollar denominated	US$107,138	US$72,663	US$67,389	US$402,979	US$230,878	US$198,690

Subsequent to December 31, 2011, Baytex added the following currency contracts:

Type	Period	Amount per month	Sales Price	Reference
Monthly spot collar	Calendar 2012	US$1.00 million	0.9800 - 1.0722	(1)
Monthly spot collar	Calendar 2012	US$1.00 million	0.9900 - 1.0720	(1)
Monthly spot collar	Calendar 2012	US$0.50 million	0.9900 - 1.0785	(1)
Monthly spot collar	June 2012 to December 2012	US$1.00 million	0.9800 - 1.0720	(1)
Monthly average rate forward	January 2012 to June 2012	US$1.00 million	1.0500	(1)(2)

(1) Actual contract rate (CAD/USD).
(2) Counterparty has the option to extend the term of the contract for an additional six months.

Interest rate risk

The Company's interest rate risk arises from its floating rate bank credit facilities. As at December 31, 2011, $312.0 million of the Company's total debt is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income before taxes for the year ended December 31, 2011 by approximately $3.4 million. Baytex uses a combination of short-term and long-term debt to finance operations. The bank loan is typically at floating rates of interest and long-term debt is typically at fixed rates of interest.

As at December 31, 2011, Baytex had the following interest rate swap financial derivative contracts:

Type	Period	Notional Principal Amount	Fixed interest rate	Floating rate index
Swap – pay fixed, receive floating	September 27, 2011 to September 27, 2014	US$90.0 million	4.06%	3-month LIBOR
Swap – pay fixed, received floating	September 25, 2012 to September 25, 2014	US$90.0 million	4.39%	3-month LIBOR

When assessing the potential impact of forward interest rate changes on financial derivative contracts outstanding as at December 31, 2011, an increase of 100 basis points would decrease the unrealized loss at December 31, 2011 by $4.2 million, while a decrease of 100 basis points would increase the unrealized loss at December 31, 2011 by $3.3 million.

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivative instruments is governed under formal policies and is subject to limits established by the Board of Directors of Baytex. Under the Company's risk management policy, financial derivatives are not to be used for speculative purposes.

When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 31, 2011, a 10% increase would increase the unrealized loss at December 31, 2011 by $43.2 million, while a 10% decrease would decrease the unrealized loss at December 31, 2011 by $43.2 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2011, a 10% increase would increase the unrealized loss at December 31, 2011 by $1.1 million, while a 10% decrease would decrease the unrealized loss at December 31, 2011 by $1.0 million.

Financial Derivative Contracts

At December 31, 2011, Baytex had the following financial derivative contracts:

Oil	Period	Volume	Price/Unit(1)	Index
Fixed – Sell	January to March 2012	1,750 bbl/d	US$93.83	WTI
Fixed – Sell	January to June 2012	3,600 bbl/d	US$100.59	WTI
Time Spread	January to December 2012	500 bbl/d	Dec 2014 plus US$3.25	WTI
Time Spread	January to December 2012	500 bbl/d	Dec 2014 plus US$0.65	WTI
Fixed – Sell	Calendar 2012	7,450 bbl/d	US$93.44	WTI
Price collar	Calendar 2012	400 bbl/d	US$98.00 - 104.52	WTI
Price collar	Calendar 2012	300 bbl/d	US$100.00 - 104.90	WTI
Price collar	Calendar 2012	200 bbl/d	US$97.50 - 104.25	WTI
Price collar	Calendar 2012	300 bbl/d	US$100.00 - 105.92	WTI
Fixed – Buy	Calendar 2012	200 bbl/d	US$102.50	WTI
Fixed – Buy	January to June 2013	250 bbl/d	US$102.07	WTI
Fixed – Buy	July to December 2013	350 bbl/d	US$101.70	WTI
Fixed – Buy	Calendar 2014	380 bbl/d	US$101.06	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.

Natural Gas	Period	Volume	Price/Unit[1]	Index
Basis swap	January to June 2012	1,000 mmBtu/d	NYMEX less US$0.328	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.390	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.370	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.450	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.430	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.410	AECO
Basis swap	Calendar 2012	1,500 mmBtu/d	NYMEX less US$0.490	AECO
Basis swap	Calendar 2012	1,000 mmBtu/d	NYMEX less US$0.515	AECO
Basis swap	Calendar 2012	2,000 mmBtu/d	NYMEX less US$0.520	AECO
Basis swap	Calendar 2012	2,500 mmBtu/d	NYMEX less US$0.530	AECO
Sold call	Calendar 2012	6,000 mmBtu/d	US$5.25	NYMEX
Fixed – Sell	Calendar 2012	7,000 mmBtu/d	US$5.07	NYMEX

(1) Based on the weighted average price/unit for the remainder of the contract.

Financial derivatives are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income and comprehensive income:

	Years Ended December 31	
	2011	2010
Realized loss (gain) on financial derivatives	$ 1,864	$ (48,129)
Unrealized loss on financial derivatives	16,166	43,312
Loss (gain) on financial derivatives	$ 18,030	$ (4,817)

Included in unrealized gain on financial derivatives is a loss of $5.1 million for the year ended December 31, 2010, respectively ($nil for year ended December 31, 2011) relating to the conversion feature of the convertible debentures.

Subsequent to December 31, 2011, Baytex added the following financial derivative contracts:

Oil	Period	Volume	Price/Unit[1]	Index
Fixed – Sell	January to June 2012[2]	500 bbl/d	US$108.00	WTI
Fixed – Sell	January to June 2012[2]	500 bbl/d	US$108.45	WTI
Fixed – Sell	January to December 2012	500 bbl/d	US$101.70	WTI
Fixed – Sell	March 2012	2,500 bbl/d	US$108.30	WTI
Fixed – Sell	March to December 2012	200 bbl/d	US$97.00-US$117.60	WTI
Fixed – Sell	March to December 2012	300 bbl/d	US$97.00-US$116.60	WTI
Fixed – Sell	April to June 2012	1,200 bbl/d	US$105.23	WTI
Fixed – Sell	April to June 2012[3]	500 bbl/d	US$107.70	WTI
Fixed – Sell	July to September 2012	300 bbl/d	US$107.38	WTI
Fixed – Sell	July to December 2012[2]	500 bbl/d	US$107.30	WTI
Fixed – Sell	July to December 2012[4]	500 bbl/d	US$108.80	WTI
Fixed – Sell	July to December 2012[4]	500 bbl/d	US$108.65	WTI
Fixed – Sell	July to December 2012[4]	500 bbl/d	US$107.80	WTI
Fixed – Sell	July to December 2012[4]	500 bbl/d	US$109.25	WTI

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Counterparty has the option to extend the term of the contract for an additional six months.
(3) Counterparty has the option to extend the term of the contract for an additional six months on 250 bbl/d.
(4) Counterparty has the option to increase the volume on the contract to 1,000 bbl/d.

Physical Delivery Contracts

At December 31, 2011, the following physical delivery contracts were entered into and continue to be held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Weighted Average Price/Unit[(1)]
WCS Blend	October 2011 to December 2014	2,000 bbl/d	WTI × 81.00%
WCS Blend	January to March 2012	4,000 bbl/d	WTI less US$11.78
WCS Blend	April to June 2012	1,500 bbl/d	WTI less US$13.42
WCS Blend	July to September 2012	500 bbl/d	WTI less US$15.00
WCS Blend	October to December 2012	500 bbl/d	WTI less US$18.00
WCS Blend	Calendar 2012	4,000 bbl/d	WTI less US$18.13
WCS Blend	January to June 2013	1,250 bbl/d	WTI × 80.00%
WCS Blend	January to June 2013	4,250 bbl/d	WTI less US$18.18
WCS Blend	July to December 2013	2,750 bbl/d	WTI × 80.00%
WCS Blend	July to December 2013	2,750 bbl/d	WTI less US$21.00

(1) Based on the weighted average price/unit for the remainder of the contract.

Subsequent to December 31, 2011, Baytex added the following physical purchase contract:

Condensate (diluent)	Period	Volume	Price/Unit
Condensate	April 2012 to March 2013	640 bbl/d	WTI plus US$6.70

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include continuously monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements and opportunities to issue additional common shares. As at December 31, 2011, Baytex had available unused bank credit facilities in the amount of $388.0 million.

The timing of cash outflows (excluding interest) relating to financial liabilities is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 225,831	$ 225,831	$ –	$ –	$ –
Dividends payable to shareholders	25,936	25,936	–	–	–
Bank loan[(1)]	311,960	–	311,960	–	–
Long-term debt[(2)]	302,550	–	–	150,000	152,550
	$ 866,277	$ 251,767	$ 311,960	$ 150,000	$ 152,550

(1) The bank loan is a three-year covenant-based revolving loan that is extendible annually, for a one, two or three year period (subject to a maximum three-year term at any time). Unless extended, the revolving period will end on June 14, 2014 with all amounts to be re-paid on such date.
(2) Principal amount of instruments.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. Most of the Company's trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit and/or parental guarantees may be

obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. Due to the short term nature of accounts receivable, the maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers that all financial assets that are not impaired or past due for each of the reporting dates under review are of good credit quality. None of the Company's financial assets are secured by collateral.

Baytex considers all amounts greater than 90 days as past due. The average collection on petroleum and natural gas sales is 30 to 60 days from the date of the invoice. Should Baytex determine that the ultimate collection of a receivable is in doubt based on the processes for managing credit risk, the carrying amount of accounts receivable is reduced through the use of an allowance for doubtful accounts and the amount of the loss is recognized in net income. If the Company subsequently determines that an account is uncollectible, the account is written-off with a corresponding change to allowance for doubtful accounts. For the year ended December 31, 2011, $0.9 million was written-off in relation to balances already previously provided for (year ended December 31, 2010 – $0.5 million write-off).

Movements in allowance for doubtful accounts were as follows:

At January 1, 2010	$	(2,336)
Foreign currency translation		4
Charge for the period		–
Amounts written off		479
Unused amounts reversed		–
At December 31, 2010	$	(1,853)
Foreign currency translation		(2)
Charge for the period		–
Amounts written off		896
Unused amounts reversed		–
At December 31, 2011	$	(959)

Included in the allowance for doubtful accounts are individually impaired trade receivables of $0.3 million (December 31, 2010 – $0.2 million). As at December 31, 2011, accounts receivable that Baytex has deemed past due but not impaired is $4.5 million (December 31, 2010 – $4.6 million).

24. OPERATING LEASES

At December 31, 2011, the future minimum lease payments under non-cancellable operating lease rentals are payable as follows:

		Total		Less than 1 year		1-5 years		Beyond 5 years
Gross operating leases	$	50,984	$	6,286	$	24,446	$	20,252
Operating subleases		(867)		(533)		(334)		–
Net operating leases	$	50,117	$	5,753	$	24,112	$	20,252

Operating lease and sublease payments recognized as an expense during the year ended December 31, 2011 was $5.5 million (December 31, 2010 – $4.8 million).

Baytex has entered into operating leases on office buildings in the ordinary course of business. The Company's operating lease agreements do not contain any contingent rent clauses. The Company has renewal options to extend its lease at the option of the lessee at lease payments based on market prices on one of its leased office buildings. None of the operating lease agreements contain purchase options or escalation clauses or any restrictions regarding dividends, further leases or additional debt.

25. RELATED PARTIES

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Transaction with key management personnel (including directors):

	December 31, 2011	December 31, 2010
Short-term employee benefits	$ 8,585	$ 7,550
Share-based compensation	14,271	47,876
Total compensation for key management personnel	$ 22,856	$ 55,426

26. COMMITMENTS AND CONTINGENCIES

At December 31, 2011 Baytex had processing and transportation obligations as summarized below:

	Total	Less than 1 year	1-2 years	2-3 years	3-4 years	4-5 years	Beyond 5 years
Processing and transportation agreements	$ 5,198	$ 3,238	$ 1,881	$ 79	$ –	$ –	$ –

At December 31, 2011 Baytex has $0.4 million of outstanding letters of credit ($nil – December 31, 2010 and January 1, 2010).

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

27. GEOGRAPHIC INFORMATION

Baytex has operations principally in Canada and the United States. Baytex's entire operating activities are related to the acquisition, development and production of oil and natural gas. The following geographic information has been prepared by segregating the results into the geographic areas in which Baytex operates.

	Canada		United States		Total	
	2011	2010	2011	2010	2011	2010
Years ended December 31						
Gross revenues to external customers	$ 1,267,589	$ 986,041	$ 41,225	$ 19,095	$ 1,308,814	$ 1,005,136
Royalties	(200,786)	(165,631)	(11,386)	(5,213)	(212,172)	(170,844)
Revenue, net of royalties to external customers	$ 1,066,803	$ 820,410	$ 29,839	$ 13,882	$ 1,096,642	$ 834,292
As at December 31						
Exploration and evaluation assets	$ 76,592	$ 58,233	$ 53,182	$ 54,849	$ 129,774	$ 113,082
Oil and gas properties	1,812,206	1,484,463	219,954	140,166	2,032,160	1,624,629
Other plant and equipment	24,965	27,270	268	280	25,233	27,550
Goodwill	37,755	37,755	–	–	37,755	37,755
Total non current assets	$ 1,963,727	$ 1,621,554	$ 271,508	$ 191,954	$ 2,235,235	$ 1,813,508

28. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of the business through maintenance of investor, creditor and market confidence.

Baytex considers its capital structure to include total monetary debt and shareholders'/unitholders' equity. Total monetary debt is the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred tax assets or liabilities and unrealized gains or losses on financial derivative contracts)) and the principal amount of long-term debt. At December 31, 2011, total monetary debt was $650.6 million.

The Company's financial strategy is designed to maintain a flexible capital structure consistent with the objectives stated above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. Baytex is in compliance with all financial covenants relating to its senior unsecured debentures and the credit facilities of Baytex Energy. In order to manage its capital, the Company may adjust the amount of its dividends, adjust its level of capital spending, issue new shares or debt, or sell assets to reduce debt.

Baytex monitors capital based on the current and projected ratio of total monetary debt to funds from operations and the current and projected level of its undrawn bank credit facilities. Funds from operations is a financial term commonly used in the oil and gas industry. Funds from operations represents cash flow from operating activities before changes in non-cash working capital and other operating items. The Company's objectives are to maintain a total monetary debt to funds from operations ratio of less than two times and to have access to undrawn bank credit facilities of not less than $100 million. The total monetary debt to funds from operations ratio may increase beyond two times, and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors, including acquisitions, changes to commodity prices and changes in the credit market. To facilitate management of the total monetary debt to funds from operations ratio and the level of undrawn bank credit facilities, the Company continuously monitors its funds from operations and evaluates its dividend policy and capital spending plans.

Although Baytex has changed its legal form to a corporation, the Company's financial objectives and strategy over the last two completed fiscal years as described above have remained substantially unchanged. These objectives and strategy are reviewed on an annual basis and Baytex believes its financial metrics are within acceptable limits pursuant to its capital management objectives.

29. FIRST-TIME ADOPTION OF INTERNATIONAL FINANCIAL REPORTING STANDARDS

The Company has prepared financial statements which comply with IFRS applicable for periods beginning on or after January 1, 2011 and the significant accounting policies meeting those requirements are described in note 3.

The general principle that should be applied on first-time adoption of IFRS is that standards in force at the first reporting date should be applied retrospectively. However, IFRS 1, "First-Time Adoption of International Financial Reporting Standards", provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas. The Company has taken all mandatory exceptions and the following optional exemptions:

- IFRS 2, "Share-based Payment", has not been applied to any liabilities arising from share-based payment transactions that settled before January 1, 2010.
- Deemed costs of oil and gas assets are based on exploration and evaluation assets at the amount determined under previous GAAP and assets in the development or production phases at the amount determined for the cost centre under previous GAAP, allocated to the cost centres' underlying assets pro rata using reserve values as of January 1, 2010.
- IFRS Interpretations Committee ("IFRIC") 4, "Determining whether an Arrangement contains a Lease", transition rules have been applied that allow determination of whether any existing arrangement at January 1, 2010 contains a lease on the basis of the facts and circumstances existing at that date.
- IFRS 3, "Business Combinations", has not been applied to acquisitions of subsidiaries or of interests in associates and joint ventures that occurred before January 1, 2010, the Company's date of transition.
- Cumulative translation differences are deemed to be $nil at January 1, 2010 and deficit adjusted by the same amount.

- Asset retirement liabilities included in the cost of property, plant and equipment are measured as at January 1, 2010 in accordance with IAS 37, "Provisions, Contingent Liabilities and Contingent Assets", and the difference between that amount and the carrying amount of those liabilities at January 1, 2010 determined under previous GAAP are recognized directly in deficit.

- IAS 23, "Borrowing Costs", transition rules have been applied that allow application of the standard to borrowing costs related to qualifying assets for which the commencement date for capitalization is on or after the effective date, January 1, 2010.

Baytex Energy Corp.
Consolidated Statements of Income and Comprehensive Income – IFRS
(thousands of Canadian dollars)

	Note	Previous GAAP	Effect of transition to IFRS	IFRS
		Year Ended December 31, 2010		
Revenues				
Petroleum and natural gas	F, N	$ 1,005,136	$ (170,844)	$ 834,292
Royalties	N	(162,332)	162,332	–
Gain on financial derivatives		9,935	(9,935)	–
		852,739	(18,447)	834,292
Expenses				
Exploration and evaluation	B	–	24,502	24,502
Production and operating		171,740	(36)	171,704
Transportation and blending		188,591	–	188,591
General and administrative		39,774	973	40,747
Unit-based compensation	J	8,344	85,855	94,199
Financing costs	H, I	32,828	1,742	34,570
Gain on divestitures of oil and gas properties	C	–	(16,227)	(16,227)
Gain on financial derivatives	G	–	(4,817)	(4,817)
Foreign exchange gain		(9,148)	–	(9,148)
Depletion and depreciation	D	266,527	(63,731)	202,796
		698,656	28,261	726,917
Net income before income taxes		154,083	(46,708)	107,375
Income tax expense (recovery)				
Current	F	8,512	(8,512)	–
Deferred	L, M	(32,060)	(92,180)	(124,240)
		(23,548)	(100,692)	(124,240)
Net income attributable to unitholders		$ 177,631	$ 53,984	$ 231,615
Other comprehensive income (loss)				
Foreign currency translation adjustment		(10,708)	385	(10,323)
Comprehensive income		$ 166,923	$ 54,369	$ 221,292

Baytex Energy Corp.
Consolidated Statements of Financial Position – IFRS
(thousands of Canadian dollars) (unaudited)

As at	Note	December 31, 2010 Previous GAAP	December 31, 2010 Effect of transition to IFRS	December 31, 2010 IFRS	January 1, 2010 Previous GAAP	January 1, 2010 Effect of transition to IFRS	January 1, 2010 IFRS
Assets							
Current assets							
Cash	O	$ –	$ –	$ –	$ 10,177	$ –	$ 10,177
Trade and other receivables	A	151,792	–	151,792	137,154	–	137,154
Crude oil inventory		1,802	–	1,802	1,384	–	1,384
Future income tax asset	A,M	5,480	(5,480)	–	1,371	(1,371)	–
Financial derivatives		13,921	–	13,921	29,453	–	29,453
		172,995	(5,480)	167,515	179,539	(1,371)	178,168
Non-current assets							
Deferred income tax asset	A,M	150,190	(142,320)	7,870	418	1,371	1,789
Financial derivatives		2,622	–	2,622	2,541	–	2,541
Exploration and evaluation assets	B	–	113,082	113,082	–	124,621	124,621
Oil and gas properties	A,C,D,I	1,683,650	(59,021)	1,624,629	1,663,752	(151,717)	1,512,035
Other plant and equipment	E	–	27,550	27,550	–	27,096	27,096
Goodwill		37,755	–	37,755	37,755	–	37,755
		$ 2,047,212	$ (66,189)	$ 1,981,023	$ 1,884,005	$ –	$ 1,884,005
Liabilities							
Current liabilities							
Trade and other payables	A	$ 179,269	$ 4,045	$ 183,314	$ 180,493	$ 6,023	$ 186,516
Distributions payable to unitholders		22,742	–	22,742	19,674	–	19,674
Bank loan		–	–	–	265,088	–	265,088
Convertible debentures		–	–	–	7,736	–	7,736
Future income tax liability	A,M	3,756	(3,756)	–	8,683	(8,683)	–
Financial derivatives	G	20,312	–	20,312	4,650	7,354	12,004
		226,079	289	226,368	486,324	4,694	491,018
Non-current liabilities							
Bank loan		303,773	–	303,773	–	–	–
Long-term debt	H	150,000	(3,107)	146,893	150,000	(3,502)	146,498
Deferred credit	L	109,800	(109,800)	–	–	–	–
Asset retirement obligations	I	52,373	117,238	169,611	54,593	87,276	141,869
Unit-based payment liability	J	–	–	–	–	91,559	91,559
Deferred income tax liability	A,M	167,302	(152,919)	14,383	179,673	(18,954)	160,719
Financial derivatives		8,859	–	8,859	1,418	–	1,418
		1,018,186	(148,299)	869,887	872,008	161,073	1,033,081
Shareholders'/Unitholders' Equity							
Shareholders' capital	J	1,390,034	94,301	1,484,335	–	–	–
Unitholders' capital	G,J	–	–	–	1,295,931	35,230	1,331,161
Conversion feature of convertible debentures	G	–	–	–	374	(374)	–
Contributed surplus	J	20,131	108,998	129,129	20,371	(20,371)	–
Accumulated other comprehensive (loss) income	K	(14,607)	4,284	(10,323)	(3,899)	3,899	–
Deficit		(366,532)	(125,473)	(492,005)	(300,780)	(179,457)	(480,237)

	1,029,026	82,110	1,111,136	1,011,997	(161,073)	850,924
	$ 2,047,212	$ (66,189)	$ 1,981,023	$ 1,884,005	$ –	$ 1,884,005

A) Presentation Differences

Certain presentation differences between previous GAAP and IFRS have no impact on reported comprehensive income or total equity.

Some line items are described differently (renamed) under IFRS compared to previous GAAP. These line items are as follows (with previous GAAP descriptions in brackets):

- Trade and other receivables (Accounts receivable)
- Oil and gas properties (Petroleum and natural gas properties)
- Deferred income tax asset/liability (Future income tax asset/liability)
- Trade and other payables (Accounts payable and accrued liabilities)

B) Exploration and Evaluation

Under previous GAAP, petroleum and natural gas properties included certain exploration and evaluation expenditures incurred within a country-by-country cost centre. Under IFRS, such exploration and evaluation expenditures are recognized as tangible or intangible based on their nature and subject to technical, commercial and management review quarterly to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are expensed.

Exploration and evaluation assets at January 1, 2010 were deemed to be $124.6 million, being the amount recorded as the undeveloped land balance under previous GAAP. This has resulted in the reclassification from property, plant and equipment to intangible exploration assets of $124.6 million in the opening IFRS statement of financial position.

During the year ended December 31, 2010, Baytex expensed $18.9 million of exploration and evaluation assets related to lease expiries and $5.6 million in direct exploration costs. For the year ended December 31, 2010, Baytex had exploration and evaluation capital expenditures of $37.4 million, corporate acquisitions of $2.5 million, divestitures of $0.1 million, transfers to oil and gas properties of $29.1 million, transfers to expense related to lease expiries of $18.9 million and a decrease due to foreign currency translation of $3.3 million.

C) Oil and Gas Properties

IFRS 1 allows an entity that used full cost accounting under its previous GAAP to elect, at its time of adoption, to measure exploration and evaluation assets at the amount determined under the entity's previous GAAP and to measure oil and gas assets in the development and production phases by allocating the amount determined under the entity's previous GAAP for those assets to the underlying assets pro rata using reserve volumes or reserve values as of that date. The Company has allocated the amount recognized under previous GAAP as at January 1, 2010 using reserve values to the assets at an area level. This has resulted in oil and gas properties of $1,512.0 million in the opening IFRS statement of financial position.

Previous GAAP utilized full cost accounting whereby gains and losses were not recognized upon the divestiture of oil and gas assets unless such a divestiture would alter the rate of depletion by 20% or more. Under IFRS, gains and losses are recognized based on the difference between the net proceeds from the divestiture and the carrying value of the asset disposed. For the year ended December 31, 2010, a gain of $16.2 million was recognized relating to a divestiture of oil and gas assets.

D) Depletion

Upon transition to IFRS, the Company adopted a policy of depleting oil and gas properties on a "units of production" basis over proved plus probable reserves on an area basis rather than a cost pool basis under previous GAAP. The depletion policy under previous GAAP was units of production over proved reserves on a country basis.

There is no impact to depletion on transition to IFRS at January 1, 2010. For the year ended December 31, 2010, this change resulted in a decrease in depletion expense of $67.4 million with a corresponding increase in oil and gas properties.

E) Other Plant and Equipment

Contains amounts previously grouped within petroleum and natural gas properties.

F) Current Income Tax Expense

Under previous GAAP, Saskatchewan resource surcharge expense was classified as current income tax. Under IFRS, Saskatchewan resource surcharge is considered a royalty and is netted against petroleum and natural gas revenues. Saskatchewan resource surcharge for the year ended December 31, 2010 netted in revenues is $8.5 million.

G) Conversion Feature of Convertible Debentures

Under previous GAAP, the convertible debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' or shareholders' equity. The debt portion accreted up to the principal balance at maturity. If the debentures were converted to trust units, a portion of the value of the conversion feature under unitholders' equity was reclassified to unitholders' capital along with principal amounts converted.

Under IFRS, the conversion feature of the convertible debentures has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the derivative liability are recognized in the statements of income and comprehensive income. If the debentures were converted to trust units, the fair value of the conversion feature under financial derivative liability was reclassified to unitholders'/shareholders' capital along with the principal amounts converted. The impact on adoption to IFRS at January 1, 2010 was an additional liability of $7.4 million, an increase of $33.4 million in unitholders' capital with a corresponding $40.4 million charge to deficit and a decrease of $0.4 million in the conversion feature of convertible debentures.

Under IFRS, for the year ended December 31, 2010, the increase in unitholders'/shareholders' equity of $12.1 million and the increase of $0.4 million in conversion feature of convertible debentures had a corresponding decrease in the $7.4 million liability recorded at January 1, 2010 and a $5.1 million decrease in gain on financial derivatives in net income.

H) Long-term Debt

Under previous GAAP, the Company's policy was to immediately expense transaction costs that are directly attributable to the acquisition or issue of a financial asset or financial liability. Under IFRS, the transaction costs for financial instruments carried at amortized cost are included in the calculation of the effective interest rate and effectively amortized through net income over the term of the instrument. Baytex's $150.0 million principal amount of Series A senior unsecured debentures are classified as other financial liabilities. Under IFRS, the senior unsecured debentures are carried at amortized cost, net of the associated $3.6 million transaction costs, which will accrete up to the principal balance at maturity using the effective interest rate. Under IFRS, a reduction in the long-term debt liability of $3.5 million had a corresponding decrease in deficit at January 1, 2010. Accretion expense included in finance costs for the year ended December 31, 2010 is $0.4 million.

I) Asset Retirement Obligations

Under IFRS, Baytex uses a risk free interest rate to discount the estimated fair value of its asset retirement obligations associated with the related oil and gas properties. Under previous GAAP, the Company used a credit-adjusted risk free interest rate. A lower discount rate under IFRS increases the asset retirement obligations. In addition, under IFRS the asset retirement obligations are measured using the best estimate of the expenditures to be incurred and current discount rates at each remeasurement date with the corresponding adjustment to the cost of the related oil and gas properties. Existing liabilities under previous GAAP are not remeasured using current discount rates.

Under previous GAAP, the Company's asset retirement obligations were recorded using the credit-adjusted risk free rate of 8.0%. Under IFRS, the Company's asset retirement obligations are recorded using the risk free rate of 3.5% at December 31, 2010 (4.0% at January 1, 2010 and 3.5% at December 31, 2010). Under IFRS, an additional liability

of $87.3 million was charged to deficit at January 1, 2010. At December 31, 2010, excluding the January 1, 2010 adjustment, the lower discount rates used resulted in an additional liability of $30.1 million and a resulting $29.2 million increase to the related oil and gas properties. At December 31, 2010, excluding the January 1, 2010 adjustment, the lower discount rates used resulted in an additional liability of $30.0 million and a resulting $28.7 million increase to the related oil and gas properties.

For the year ended December 31, 2010, the $4.5 million accretion expense on asset retirement obligations under previous GAAP was reclassified to finance costs and an additional accretion expense on asset retirement obligations of $1.4 million has been recognized in net income under IFRS.

J) Unit-based Compensation

Under previous GAAP, the obligation associated with the Unit Rights Plan is considered to be equity-based and the related unit-based compensation was calculated using the binomial-lattice model to estimate the fair value of the outstanding unit rights at grant date. The exercise of unit rights was recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Under IFRS, prior to the conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability is remeasured at each reporting date and at settlement date. Any changes in fair value are recognized in net income for the period. For periods prior to the conversion to a corporation remeasuring the fair value of the obligation each reporting period will increase or decrease the unit-based payment liability, unitholders' capital and compensation expense recognized. Upon conversion to a corporation, the outstanding Unit Rights Plan was modified to become the new Share Rights Plan, effectively changing the related classification from liability-settled to equity-settled. The expense recognized from the date of the plan modification over the remainder of the vesting period is determined based on the fair value of the reclassified unit rights at the date of the modification. Upon transition of IFRS at January 1, 2010, an additional unit-based payment liability of $91.6 million and a decrease of $20.4 million in contributed surplus resulted in a corresponding $71.2 million charge to deficit.

Under IFRS, in addition to the January 1, 2010 adjustments discussed above, at December 31, 2010 immediately prior to the conversion to a corporation, the remeasurement of the liability at reporting date and at settlement date resulted in the recognition of an additional unit-based compensation expense of $85.9 million, with a corresponding decrease of $0.3 million in contributed surplus, an increase of $48.0 million in shareholders'/unitholders' equity and an increase of $37.6 million in unit-based payment liability.

K) Accumulated Other Comprehensive Loss

Under previous GAAP, amounts are composed entirely of currency translation adjustments on self-sustaining foreign operations. Under IFRS, the Company has elected to deem cumulative currency translation differences as $nil at January 1, 2010. At January 1, 2010, this has resulted in a decrease in accumulated other comprehensive loss with a corresponding increase in deficit of $3.9 million.

L) Deferred Credit

Baytex acquired several private entities to be used in its internal financing structure. Under previous GAAP, the excess of amounts assigned to the acquired assets over the consideration paid is classified as a deferred credit. Under IFRS, the deferred credit is derecognized through net income as a deferred income tax recovery. For the year ended December 31, 2010, a deferred income tax recovery of $109.8 million was recorded in net income for amounts previously recognized as a deferred credit.

M) Deferred Income Taxes

Under IFRS, deferred income taxes are required to be presented as non-current. Upon transition to IFRS, the Company recognized a $27.6 million reduction in the net deferred income tax liability entirely resulting from the tax impact of the adjustments from previous GAAP to IFRS with a decrease to deficit of $25.8 million and a decrease to unitholders' capital of

$1.8 million.

For the year ended December 31, 2010, the application of the IFRS adjustments resulted in a $92.2 million increase to the Company's deferred income tax recovery. The increase in deferred income tax recovery is due to the deferred credit derecognized through net income under IFRS.

Under IFRS, taxable and deductible temporary differences related to the legal entity of the Trust must be measured using the highest marginal personal tax rate of 39%, as opposed to the corporate tax rates used under previous GAAP, resulting in an increase to the deferred income tax asset of $5.1 million at January 1, 2010. Upon conversion to a dividend paying corporation on December 31, 2010, the total deferred income tax asset related to the Trust was adjusted to the corporate tax rate of approximately 25% and derecognized through net income on December 31, 2010.

N) Royalties

Under previous GAAP, gross petroleum and natural gas revenues and royalties were presented separately. Under IFRS, petroleum and natural gas revenues are presented net of crown, third-party, gross overriding royalties and production taxes.

O) Statements of Cash Flows

With the exception of a $28.5 million interest paid reclass from operating activities to financing activities for the year ended December 31, 2010, the transition from previous GAAP to IFRS had no material effect on the reported cash flows generated by the Company.

30. CONSOLIDATING FINANCIAL INFORMATION – BASE SHELF PROSPECTUS

On August 4, 2011, Baytex filed a Short Form Base Shelf Prospectus with the securities regulatory authorities in each of the provinces of Canada (other than Québec) and a Registration Statement with the United States Securities and Exchange Commission (collectively, the "Shelf Prospectus"). The Shelf Prospectus allows Baytex to offer and issue common shares, subscription receipts, warrants, options and debt securities by way of one or more prospectus supplements at any time during the 25-month period that the Shelf Prospectus remains in place. The securities may be issued from time to time, at the discretion of Baytex, with an aggregate offering amount not to exceed $500 million (Canadian).

Any debt securities issued by Baytex pursuant to the Shelf Prospectus will be guaranteed by all of its direct and indirect wholly-owned material subsidiaries (the "Guarantor Subsidiaries"). The guarantees of the Guarantor Subsidiaries are full and unconditional and joint and several. These guarantees may in turn be guaranteed by Baytex. Other than investments in its subsidiaries, Baytex has no independent assets or operations.

Pursuant to the credit agreement governing Baytex Energy's credit facilities, Baytex Energy and its subsidiaries are prohibited from paying dividends to their shareholders that would have, or would reasonably be expected to have, a material adverse effect or would adversely affect or impair the ability or capacity of Baytex Energy to pay or fulfill any of its obligations under the credit agreement. In addition, Baytex Energy may not permit any of its subsidiaries to pay any dividends during the continuance of a default or event of default under the credit agreement.

The following tables present consolidating financial information as at December 31, 2011, December 31, 2010 and January 1, 2010 and for the years ended December 31, 2011 and 2010 for: 1) Baytex, on a stand-alone basis, 2) Guarantor subsidiaries, on a stand-alone basis, 3) non-guarantor subsidiaries, on a stand-alone basis and 4) Baytex, on a consolidated basis.

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
As at December 31, 2011					
Current assets	$ 351	$ 225,850	$ 374	$ –	$ 226,575
Intercompany advances and investments	1,753,047	(515,492)	72,787	(1,310,342)	–
Non-current assets	2,435	2,232,800	–	–	2,235,235
Current liabilities	34,502	242,303	167	–	276,972
Bank loan and long-term debt	297,731	311,960	–	–	609,691
Asset retirement obligation and other non-current liabilities	$ –	$ 368,413	$ –	$ –	$ 368,413
As at December 31, 2010					
Current assets	$ 15	$ 167,473	$ 27	$ –	$ 167,515
Intercompany advances and investments	1,687,861	(456,094)	72,318	(1,304,085)	–
Non-current assets	1,138	1,812,370	–	–	1,813,508
Current liabilities	27,539	198,788	41	–	226,368
Bank loan and long-term debt	146,893	303,773	–	–	450,666
Asset retirement obligation and other non-current liabilities	$ –	$ 192,853	$ –	$ –	$ 192,853
As at January 1, 2010					
Current assets	$ 412	$ 177,608	$ 148	$ –	$ 178,168
Intercompany advances and investments	1,522,661	(1,522,596)	63,892	(63,957)	–
Non-current assets	42,515	1,663,322	–	–	1,705,837
Current liabilities	39,577	451,357	84	–	491,018
Bank loan and long-term debt	146,498	–	–	–	146,498
Asset retirement obligation and other non-current liabilities	$ –	$ 395,565	$ –	$ –	$ 395,565

(thousands of Canadian dollars)		Baytex		Guarantor Subsidiaries		Non-guarantor Subsidiaries		Consolidation Adjustments		Total Consolidated
Year ended December 31, 2011										
Revenues, net of royalties	$	22,012	$	1,098,415	$	9,649	$	(33,434)	$	1,096,642
Production, operation and exploration		–		223,042		–		–		223,042
Transportation and blending		–		249,850		–		–		249,850
General, administrative and share-based compensation		1,596		72,842		257		(1,515)		73,180
Financing, derivatives, foreign exchange and other gains/losses		27,497		36,999		(48)		(31,919)		32,529
Depletion and depreciation		–		248,468		–		–		248,468
Deferred income tax (recovery) expense		(1,298)		53,439		–		–		52,141
Net (loss) income	$	(5,783)	$	213,775	$	9,440	$	–	$	217,432

(thousands of Canadian dollars)		Baytex		Guarantor Subsidiaries		Non-guarantor Subsidiaries		Consolidation Adjustments		Total Consolidated
Year ended December 31, 2010										
Revenues, net of royalties	$	262,138	$	800,887	$	10,537	$	(239,270)	$	834,292
Production, operation and exploration		–		196,206		–		–		196,206
Transportation and blending		–		188,591		–		–		188,591
General, administrative and unit-based compensation		1,500		134,598		348		(1,500)		134,946
Financing, derivatives, foreign exchange and other gains/losses		(15,270)		257,405		13		(237,770)		4,378
Depletion and depreciation		4,811		197,985		–		–		202,796
Deferred income tax expense (recovery)		13,495		(137,739)		4		–		(124,240)
Net income (loss)	$	257,602	$	(36,159)	$	10,172	$	–	$	231,615

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
Year ended December 31, 2011 Cash provided by (used in):					
Operating activities	$ 56,926	$ 514,581	$ 353	$ –	$ 571,860
Payment of dividends	(204,308)	9,004	(9,004)	–	(204,308)
Increase in bank loan	–	4,290	–	–	4,290
Increase (decrease) in intercompany loans	(18,008)	110,041	(92,033)	–	–
Proceeds from issuance of long-term debt	145,810	–	–	–	145,810
Increase in investments		(90,649)		90,649	–
Increase in equity	45,048	–	90,649	(90,649)	45,048
Interest paid	(25,468)	(19,297)	10,035	–	(34,730)
Financing activities	(56,926)	13,389	(353)	–	(43,890)
Additions to exploration and evaluation assets	–	(9,104)	–	–	(9,104)
Additions to oil and gas properties	–	(358,744)	–	–	(358,744)
Property acquisitions	–	(76,164)	–	–	(76,164)
Corporate acquisitions	–	(120,006)	–	–	(120,006)
Proceeds from divestitures	–	47,396	–	–	47,396
Additions to other plant and equipment, net of disposals	–	(1,252)	–	–	(1,252)
Acquisitions of financing entities	–	–	–	–	–
Change in non-cash working capital	–	(2,553)	–	–	(2,553)
Investing activities	–	(520,427)	–	–	(520,427)
Impact of foreign currency translation on cash balances	$ –	$ 304	$ –	$ –	$ 304

(thousands of Canadian dollars)	Baytex	Guarantor Subsidiaries	Non-guarantor Subsidiaries	Consolidation Adjustments	Total Consolidated
Year ended December 31, 2010 Cash provided by (used in):					
Operating activities	$ 227,665	$ 224,483	$ 9,258	$ –	$ 461,406
Payment of distributions	(188,615)	10,455	(10,455)	–	(188,615)
Increase in bank loan	–	48,045	–	–	48,045
Increase (decrease) in intercompany loans	(50,915)	55,324	(4,409)	–	–
Increase in investments	–	(2,653)	–	2,653	–
Repayment of convertible debentures	(341)	–	–	–	(341)
Increase in equity	26,021	–	2,653	(2,653)	26,021
Interest paid	(14,180)	(17,124)	2,805	–	(28,499)
Financing activities	(228,030)	94,047	(9,406)	–	(143,389)
Additions to exploration and evaluation assets	–	(37,411)	–	–	(37,411)
Additions to oil and gas properties	–	(194,208)	–	–	(194,208)
Property acquisitions	–	(22,412)	–	–	(22,412)
Corporate acquisitions	–	(40,314)	–	–	(40,314)
Proceeds from divestitures	–	19,033			19,033
Additions to other plant and equipment, net of disposals	–	(8,237)	–	–	(8,237)
Acquisitions of financing entities	–	(38,000)	–	–	(38,000)
Change in non-cash working capital	–	(5,956)	–	–	(5,956)
Investing activities	–	(327,505)	–	–	(327,505)
Impact of foreign currency translation on cash balances	$ –	$ (689)	$ –	$ –	$ (689)

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the year ended December 31, 2011. This information is provided as of March 13, 2012. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. This MD&A should be read in conjunction with the Company's audited consolidated financial statements for the years ended December 31, 2011 and 2010 (the "consolidated financial statements"), together with accompanying notes, and the Annual Information Form for the year ended December 31, 2011. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com. The consolidated financial statements for the year ended December 31, 2011 are prepared in accordance with International Financial Reporting Standards ("IFRS"). Comparative periods in 2010 have been restated to conform to IFRS presentation. Reconciliations from IFRS to Canadian general accepted accounting principles ("previous GAAP") are shown in the notes to our consolidated financial statements. The adoption of IFRS did not have a material impact on the amounts reported as funds from operations. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share or per trust unit amounts or as otherwise noted.

In this MD&A, 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, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

2011 OVERVIEW

We are a conventional oil and gas corporation with our head office in Calgary, Alberta. Through our subsidiaries, we are engaged in the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets in Canada (primarily in the provinces of British Columbia, Alberta and Saskatchewan) and in the United States (primarily in the states of North Dakota and Wyoming). We act as the primary financing vehicle for our subsidiaries by providing access to debt and equity capital markets.

During 2011, we executed a successful capital program, resulting in the replacement of 156% of production (on a proved plus probable basis) by reinvesting approximately 66% of funds from operations into exploration and development activities. Including acquisitions (net of proceeds of disposition), our capital program replaced 227% of production while reinvesting approximately 93% of funds from operations.

On February 3, 2011, we completed the acquisition of heavy oil assets located in the Reno area of northern Alberta and the Lloydminster area of western Saskatchewan. The total consideration for the acquisition of $159.3 million (net of adjustments) was funded by drawing on our revolving credit facilities.

On February 17, 2011, we completed a private placement of US$150 million principal amount of 6.75% Series B senior unsecured debentures due February 17, 2021. The net proceeds of the offering were used to repay existing indebtedness under the credit facilities and for general corporate purposes.

On August 9, 2011, we completed the acquisition of natural gas assets located in the Brewster area of west central Alberta. The total consideration for the acquisition of $22.4 million (net of adjustments) was funded by drawing on our revolving credit facilities.

In the fourth quarter of 2011, we completed two dispositions of primarily undeveloped lands for $47.4 million. In the Kaybob South area of west central Alberta, we sold six sections of leasehold, including five sections with Duvernay

rights, for $11.1 million. In the Dodsland area in southwest Saskatchewan, we sold 32,600 net acres of leasehold in the "halo" of the field for $36.3 million.

As at December 31, 2011, our total proved reserves increased 12% to 157 million boe and our total proved plus probable reserves increased 10% to 252 million boe. During the year ended December 31, 2011, our production averaged 50,132 boe/d, primarily from our properties in Canada.

CORPORATE CONVERSION

At year end 2010, Baytex Energy Trust (the "Trust") completed a plan of arrangement under the Business Corporations Act (Alberta) pursuant to which it converted its legal structure from an income trust to a corporation (the "Corporate Conversion"). Pursuant to the Corporate Conversion: (i) on December 31, 2010, holders of trust units of the Trust exchanged their trust units for our common shares on a one-for-one basis; and (ii) on January 1, 2011, the Trust was dissolved and terminated, with the result that we became the successor to the Trust. The reorganization into a corporation has been accounted for on a continuity of interest basis, and accordingly, the consolidated financial statements reflect the financial position, results of operations and cash flows as if the Company had always carried on the business formerly carried on by the Trust.

Despite the change in legal structure from a trust to a corporation, the Company's business objectives and strategies remain unchanged and the officers and directors remained the same. Baytex's activities are directed towards increasing oil production through organic property development and acquisitions, with the objectives of providing monthly income and long-term value creation for its shareholders.

Baytex will continue to direct its efforts to increase the value of its assets through development drilling and associated development activities and enhanced oil recovery activities. Baytex will also seek to acquire undeveloped and producing petroleum and natural gas properties. Baytex will primarily participate in development activities that are considered to be lower risk. Also, a minor percentage of each year's capital budget will be devoted to moderate risk development and lower risk exploration opportunities on its properties.

The common shares of Baytex trade on the Toronto Stock Exchange and the New York Stock Exchange under the trading symbol BTE. Beginning with the January 31, 2011 record date, shareholders of Baytex have received payments in the form of dividends. Prior to the Corporate Conversion on December 31, 2010, unitholders of the Trust received payments in the form of distributions.

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as funds from operations, payout ratio, total monetary debt and operating netback) which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations, payout ratio and operating netback are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Funds from Operations

We define funds from operations as cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments. However, funds from operations should not be construed as an alternative to traditional performance measures determined in accordance with IFRS or previous GAAP, such as cash flow from operating activities and net income. For a reconciliation of funds from operations to cash flow from operating activities, see "Funds from Operations, Payout Ratio and Dividends or Distributions".

Payout Ratio

We define payout ratio as cash dividends (net of participation in our dividend reinvestment plan) divided by funds from operations. We believe that this measure assists in providing a more complete understanding of certain aspects of our results of operations and financial performance, including our ability to generate the cash flow necessary to fund future dividends to shareholders and capital investments.

Total Monetary Debt

We define total monetary debt as the sum of monetary working capital (which is current assets less current liabilities (excluding non-cash items such as deferred income tax assets or liabilities and unrealized gains or losses on financial derivatives)), the principal amount of long-term debt and long-term bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities.

Operating Netback

We define operating netback as product revenue less royalties, production and operating expenses and transportation expenses divided by barrels of oil equivalent sales volume for the applicable period. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis.

RESULTS OF OPERATIONS

Production

	Years Ended December 31		
	2011	2010	Change
Daily Production			
Light oil and NGL (bbl/d)	6,769	6,539	4%
Heavy oil (bbl/d)(1)	35,252	28,585	23%
Natural gas (mmcf/d)	48.7	55.3	(12%)
Total production (boe/d)	50,132	44,341	13%
Production Mix			
Light oil and NGL	14%	15%	–
Heavy oil	70%	64%	–
Natural gas	16%	21%	–

(1) Heavy oil sales volumes may differ from reported production volumes due to changes to Baytex's heavy oil inventory. For the year ended December 31, 2011, heavy oil sales volumes were 72 bbl/d higher than production volumes (year ended December 31, 2010 – 36 bbl/d lower).

Production for the year ended December 31, 2011 averaged 50,132 boe/d, as compared to 44,341 boe/d for the same period in 2010. Light oil and NGL production for the year ended December 31, 2011 increased by 4% to 6,769 bbl/d from 6,539 bbl/d a year earlier due to development activities in the US, which increased US production by 81%, as compared to the same period in 2010, partially offset by second quarter production interruptions in North Dakota, Alberta and British Columbia. Heavy oil production for the year ended December 31, 2011 increased by 23% to 35,252 bbl/d from 28,585 bbl/d a year ago primarily due to development activities and the acquisition of producing assets in the first quarter of 2011. Natural gas production decreased by 12% to 48.7 mmcf/d for the year ended December 31, 2011, as compared to 55.3 mmcf/d for the same period. The decrease in natural gas production was primarily due to natural declines as we focused our drilling effort on our oil portfolio and, to a lesser extent, to pipeline constraints in west central Alberta partially offset by a natural gas-weighted acquisition that closed in the third quarter of 2011.

Commodity Prices

Crude Oil

For the year ended December 31, 2011, the price of West Texas Intermediate ("WTI") fluctuated from a low of US$75.67/bbl to a high of US$113.93/bbl. The average prompt WTI price for the year ended December 31, 2011 was US$95.12/bbl, or 20% higher than the corresponding 2010 price of US$79.53/bbl. 2011 was a year of significant volatility, as oil prices reacted to rapidly changing macroeconomic issues and uncertainty, political and social unrest, and underlying energy market fundamentals. Global oil demand growth from emerging market countries, including China, and several smaller oil supply disruptions, have helped support oil prices over the past year. By the end of 2011, oil markets appeared to focus on signs of improving economic activity in the United States and growing tensions over Iran's nuclear program, both of which contributing to rising oil prices.

The Western Canadian Select ("WCS") price differential to WTI, averaged 18% in the year ended December 31, 2011, unchanged from 2010. The volatility of the heavy oil differential in 2011 was marked by periodic transportation disruptions increasing differentials, which was offset by a combination of high refinery runs in the mid-continent region of the United States and new heavy oil refinery capacity in late 2011 supporting heavy oil demand and lower heavy oil differentials.

Natural Gas

For the year ended December 31, 2011, AECO natural gas prices averaged $3.68/mcf, as compared to $4.13/mcf in 2010. Natural gas prices have remained at depressed levels during 2011 due to significant natural gas production capacity additions in the United States, which have exceeded gas demand growth, and a warm start to the winter of 2011-2012 resulting in low demand.

	Years Ended December 31		
	2011	2010	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	$ 95.12	$ 79.53	20%
WCS heavy oil (US$/bbl)[2]	$ 77.97	$ 65.30	19%
Heavy oil differential[3]	(18%)	(18%)	–%
USD/CAD average exchange rate	1.0114	0.9708	4%
Edmonton par oil ($/bbl)	$ 95.56	$ 77.81	23%
AECO natural gas price ($/mcf)[4]	$ 3.68	$ 4.13	(11%)
Baytex Average Sales Prices			
Light oil and NGL ($/bbl)	$ 82.49	$ 65.90	25%
Heavy oil ($/bbl)[5]	$ 65.36	$ 60.08	9%
Physical forward sales contracts gain (loss) ($/bbl)	0.17	(0.68)	
Heavy oil, net ($/bbl)	$ 65.53	$ 59.40	10%
Total oil and NGL, net ($/bbl)	$ 68.26	$ 60.61	13%
Natural gas ($/mcf)[6]	$ 3.86	$ 4.22	(9%)
Physical forward sales contracts gain ($/mcf)	0.31	0.10	
Natural gas, net ($/mcf)	$ 4.17	$ 4.32	(3%)
Summary			
Weighted average ($/boe)[6]	$ 60.78	$ 53.75	13%
Physical forward sales contracts gain (loss) ($/boe)	0.48	(0.36)	

Weighted average, net ($/boe)	$	61.26	$	53.39	15%

(1) WTI refers to the calendar monthly average based on NYMEX prompt month WTI.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) Heavy oil differential refers to the WCS discount to WTI.
(4) AECO refers to the AECO monthly index price published by the Canadian Gas Price Reporter.
(5) Baytex's realized heavy oil prices are calculated based on sales volumes, net of blending costs.
(6) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The above pricing information in the table excludes the impact of financial derivatives.

For the year ended December 31, 2011, Baytex's average sales price for light oil and NGL was $82.49/bbl, up 25% from $65.90/bbl in the same period in 2010. Baytex's realized heavy oil price during the year ended December 31, 2011, prior to physical forward sales contracts, was $65.36/bbl, or 85% of WCS. This compares to a realized heavy oil price in the same period of 2010, prior to physical forward sales contracts, of $60.08/bbl, or 89% of WCS. The differential to WCS largely reflects the cost of blending Baytex's heavy oil with diluent to meet pipeline specifications. Net of physical forward sales contracts, Baytex's realized heavy oil price during the year ended December 31, 2011 was $65.53/bbl, up 10% from $59.40/bbl in the same period in 2010. Baytex's realized natural gas price for the year ended December 31, 2011 was $3.86/mcf prior to physical forward sales contracts and $4.17/mcf inclusive of physical forward sales contracts (year ended December 31, 2010 – $4.22/mcf prior to physical forward sales contracts and $4.32/mcf inclusive of physical forward sales contracts).

Gross Revenues

	Years Ended December 31		
($ thousands except for %)	2011	2010	Change
Oil revenue			
Light oil and NGL	$ 204,513	$ 157,603	30%
Heavy oil	843,707	618,969	36%
Total oil revenue	1,048,220	776,572	35%
Natural gas revenue	74,018	87,116	(15%)
Total oil and natural gas revenue	1,122,238	863,688	30%
Sales of heavy oil blending diluent	186,576	141,448	32%
Total petroleum and natural gas sales	$ 1,308,814	$ 1,005,136	30%

For the year ended December 31, 2011, petroleum and natural gas sales increased 30% to $1,308.8 million from $1,005.1 million for the same period in 2010. During this period, the change was driven by heavy oil revenues which increased by 36% due to a 9% increase in realized price and an 23% increase in sales volume compared to the year ended December 31, 2010.

Royalties

	Years Ended December 31		
($ thousands except for % and per boe)	2011	2010	Change
Royalties	$ 212,172	$ 170,844	24%
Royalty rates:			
Light oil, NGL and natural gas	18.7%	20.5%	–
Heavy oil	19.0%	19.5%	–
Average royalty rates(1)	18.9%	19.8%	–
Royalty expenses per boe	$ 11.59	$ 10.56	10%

(1) Average royalty rate excludes sales of heavy oil blending diluents and the effects of financial derivatives.

Total royalties for the year ended December 31, 2011 increased to $212.2 million from $170.8 million in the year ended December 31, 2010. Total royalties for the year ended December 31, 2011 were 18.9% of petroleum and natural gas revenue (excluding sales of heavy oil blending diluent), as compared to 19.8% for the same period in 2010. Royalty rates for light oil, NGL and natural gas decreased from 20.5% in the year ended December 31, 2010 to 18.7% in the year ended December 31, 2011 due to conventional oil royalty rate incentives on new wells, partially offset by higher royalty rates for properties acquired in August 2011. Royalty rates for heavy oil decreased from 19.5% in the year ended December 31, 2010 to 19.0% in the year ended December 31, 2011 due to royalty rate incentives on new wells at Seal and Kerrobert. In addition, Baytex received a positive $1.0 million Alberta Royalty Tax Credit reassessment related to 2004 and 2005 periods. This increased credit was received in the first quarter of 2011, which decreased our reported royalty rate for 2011.

Certain additional credits earned under the Alberta Royalty Drilling Credit program, which are based on drilling activity and drilling depths, are recorded as a reduction to capital expenditures, rather than as a reduction to royalties.

Financial Derivatives

	Years Ended December 31		
($ thousands)	2011	2010	Change
Realized gain (loss) on financial derivatives[1]			
Crude oil	$ (17,641)	$ 7,609	$ (25,250)
Natural gas	431	11,322	(10,891)
Foreign currency	15,230	28,119	(12,889)
Interest rate	116	1,079	(963)
Total	$ (1,864)	$ 48,129	$ (49,993)
Unrealized gain (loss) on financial derivatives[2]			
Crude oil	$ 1,237	$ (17,546)	$ 18,783
Natural gas	6,004	(641)	6,645
Foreign currency	(17,542)	(9,261)	(8,281)
Interest rate	(5,865)	(15,864)	9,999
Total	$ (16,166)	$ (43,312)	$ 27,146
Total gain (loss) on financial derivatives			
Crude oil	$ (16,404)	$ (9,937)	$ (6,467)
Natural gas	6,435	10,681	(4,246)
Foreign currency	(2,312)	18,858	(21,170)
Interest rate	(5,749)	(14,785)	9,036
Total	$ (18,030)	$ 4,817	$ (22,847)

(1) Realized gain (loss) on financial derivatives represents actual cash settlement or receipts under the financial derivatives.
(2) Unrealized gain (loss) on financial derivatives represents the change in fair value of the financial derivatives during the period.

The total loss on financial derivatives for the year ended December 31, 2011 was $18.0 million, as compared to a gain of $4.8 million for the same period in 2010. This includes a realized loss of $1.9 million and an unrealized mark-to-market loss of $16.2 million for the year ended December 31, 2011, as compared to $48.1 million in realized gains and $43.3 million in unrealized losses for the same period in 2010. The realized loss of $1.9 million for the year ended December 31, 2011 relates to the realization of losses on commodity contracts due to higher oil prices offset by gains on foreign currency contracts. The unrealized loss of $16.2 million for the year ended December 31, 2011, is mainly due to the reversal of previously recorded unrealized gains on foreign currency contracts as they are settled upon maturity and a decrease in floating 3-month London Interbank Offer Rates offset by lower natural gas price.

A summary of the risk management contracts in place as at December 31, 2011 and the accounting treatment of the Company's financial instruments are disclosed in note 23 to the consolidated financial statements as at and for the year ended December 31, 2011.

Evaluation and Exploration Expense

Evaluation and exploration expense for the year ended December 31, 2011 decreased to $13.9 million, as compared and $24.5 million for the year ended December 31, 2010, due to a decrease in the expiration of undeveloped land leases during 2011.

Production and Operating Expenses

($ thousands except for % and per boe)	Years Ended December 31 2011		2010	Change
Production and operating expenses	$ 209,177	$	171,704	22%
Production and operating expenses per boe	$ 11.43	$	10.62	8%

Production and operating expenses for the year ended December 31, 2011 increased to $209.2 million from $171.7 million for the same period of 2010 due to an increase in total production volumes from development activities and difficult weather conditions. In the winter months, Baytex experienced increased costs for energy inputs and snow removal. In the spring months, Baytex experienced increased costs due to forest fires in northern Alberta and extremely wet ground conditions in North Dakota. In the summer months, production and operating expenses increased due to the increased cost of energy inputs and a number of turnarounds conducted at operated and non-operated oil and natural gas processing facilities. Production and operating expenses were $11.43 per boe for the year ended December 31, 2011, as compared to $10.62 per boe for the same period in 2010. For the year ended December 31, 2011, production and operating expenses were $12.21 per boe of light oil, NGL and natural gas and $11.09 per barrel of heavy oil, as compared to $10.64 per boe and $10.60 per barrel, respectively, for the same period in 2010.

Transportation and Blending Expenses

($ thousands except for % and per boe)	Years Ended December 31 2011	2010	Change
Blending expenses	$ 186,576	$ 141,448	32%
Transportation expenses(1)	63,274	47,143	34%
Total transportation and blending expenses	$ 249,850	$ 188,591	32%
Transportation expense per boe(1)	$ 3.46	$ 2.92	18%

(1) Transportation expenses per boe are before the purchase of blending diluent.

Transportation and blending expenses for the year ended December 31, 2011 were $249.9 million, as compared to $188.6 million for the year ended 2010.

The heavy oil produced by Baytex requires blending to reduce its viscosity in order to meet pipeline specifications. In most cases, Baytex purchases condensate from industry producers as the blending diluent to facilitate the marketing of its heavy oil. In the year ended December 31, 2011, blending expenses were $186.6 million for the purchase of 5,031 bbl/d of condensate at $101.60 per barrel, as compared to $141.4 million for the purchase of 4,557 bbl/d at $85.05 per barrel for the same period last year. The cost of blending diluent is effectively recovered in the sale price of a blended product.

Transportation expenses were $3.46 per boe for the year ended December 31, 2011, as compared to $2.92 per boe for the same period of 2010. Transportation expenses were $0.79 per boe of light oil, NGL and natural gas and $4.58 per barrel of heavy oil in the year ended December 31, 2011, as compared to $0.85 and $4.05 per barrel, respectively, for the same period in 2010. The increase in transportation expenses per barrel of heavy oil is primarily due to a larger portion of our heavy oil production coming from Seal, which utilizes long-haul trucking to ship a portion of production volumes, and higher fuel prices.

Operating Netback

($ per boe except for % and volume)	Years Ended December 31 2011	2010	Change
Sales volume (boe/d)	50,154	44,305	13%
Operating netback[(1)]:			
Sales price[(2)]	$ 61.26	$ 53.39	15%
Less:			
Royalties	11.59	10.56	10%
Operating expenses	11.43	10.62	8%
Transportation expenses	3.46	2.92	18%
Operating netback before financial derivatives	$ 34.78	$ 29.29	19%
Financial derivatives gain (loss)[(3)]	(0.10)	2.98	(103%)
Operating netback after financial derivatives gain (loss)	$ 34.68	$ 32.27	7%

(1) Operating netback table includes revenues and costs associated with sulphur production.
(2) Sales price is shown net of blending costs and gains (losses) on physical delivery contracts.
(3) Financial derivatives reflect realized gains (losses) only.

General and Administrative Expenses

($ thousands except for % and per boe)	Years Ended December 31 2011	2010	Change
General and administrative expenses	$ 39,335	$ 40,747	(3%)
General and administrative expenses per boe	$ 2.15	$ 2.52	(15%)

General and administrative expenses for the year ended December 31, 2011 decreased to $39.3 million from $40.7 million for the year ended December 31, 2010. This decrease is a result of lower non-recurring consulting fees, including fees relating to our corporate conversion at year-end 2010, and higher capital overhead recoveries from increased capital expenditures, partially offset by increases in rent and independent reserves evaluator fees.

Share-based Compensation Expense

Compensation expense related to the Common Share Rights Incentive Plan (the "Share Rights Plan") was $15.6 million for the year ended December 31, 2011, as compared to a $94.2 million expense related to the Trust Unit Rights Incentive Plan of the Trust (the "Unit Rights Plan") for the same period in 2010. The significant decrease in compensation expense is primarily due to the change in classification of the plans. Under IFRS, prior to our conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability is re-measured at each reporting date and at settlement date. Any changes in fair value are recognized in net income for the period. Upon conversion to a corporation, the outstanding Unit Rights Plan was modified to become the new Share Rights Plan, effectively changing the related classification from liability-settled to equity-settled. The expense recognized from the date of the plan modification over the remainder of the vesting period is determined based on the fair value of the reclassified unit rights at the date of the modification.

On January 1, 2011, the Company adopted a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards may be granted to directors, officers and employees of the Company and its subsidiaries. During the year ended December 31, 2011, the Company recorded $18.2 million related to the share awards (December 31, 2010 – $nil). This increase is the result of the compensation expense related to share awards granted in 2011.

Compensation expense associated with the Share Rights Plan and the Share Award Incentive Plan is recognized in income over the vesting period of the share rights or share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the exercise of share rights or settlement of share awards is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus.

Financing Costs

	Years Ended December 31		
($ thousands except for %)	2011	2010	Change
Bank loan and other	$ 12,489	$ 12,547	–%
Long-term debt	22,935	14,198	62%
Accretion on asset retirement obligations	6,185	5,862	6%
Convertible debentures	–	320	(100%)
Debt financing costs	3,002	1,643	83%
Financing costs	$ 44,611	$ 34,570	29%

Financing costs for the year ended December 31, 2011 increased to $44.6 million, as compared to $34.6 million for the year ended December 31, 2010. The increase in financing costs was primarily attributable to the higher levels of outstanding debt, interest on the US$150.0 million principal amount of 6.75% Series B senior unsecured debentures issued on February 17, 2011 and higher fees for our revolving credit facilities.

Foreign Exchange

	Years Ended December 31		
($ thousands except for % and exchange rates)	2011	2010	Change
Unrealized foreign exchange loss (gain)	$ 8,490	$ (8,999)	194%
Realized foreign exchange gain	(656)	(149)	(340%)
Total loss (gain)	$ 7,834	$ (9,148)	186%
USD/CAD exchange rates:			
At beginning of period	1.0054	0.9555	
At end of period	0.9833	1.0054	

The foreign exchange loss for the year ended December 31, 2011 was $7.8 million, as compared to a gain of $9.1 million for the year ended December 31, 2010. This loss was comprised of an unrealized foreign exchange loss of $8.5 million and a realized foreign exchange gain of $0.7 million. The year ended December 31, 2011 unrealized loss of $8.5 million, as compared to a gain of $9.0 million for the same period in 2010, was due to the translation of the US$180.0 million portion of the bank loan as the USD/CAD foreign exchange rates strengthened (as compared to December 31, 2010) and weakened at December 31, 2010 (as compared to December 31, 2009). In addition, the translation of the US$150.0 million Series B senior unsecured debentures issued on February 17, 2011 contributed to the year-to-date unrealized foreign exchange loss as the USD/CAD foreign exchange rate strengthened from the issue date of the debentures to December 31, 2011. The realized gains for the year ended December 31, 2011 and 2010 were due to day-to-day US dollar denominated transactions.

Depletion and Depreciation

Depletion and depreciation for the year ended December 31, 2011 increased to $248.5 million from $202.8 million for the same period in 2010. On a sales-unit basis, the provision for the year ended December 31, 2011 was $13.57 per boe, as compared to $12.54 per boe for the same period in 2010 due to the increase in future development costs resulting in a higher depletable base.

Income Taxes

For the year ended December 31, 2011, deferred income tax expense totaled $52.1 million, as compared to a recovery of $124.2 million for the year ended December 31, 2010. Prior to its conversion from a mutual fund trust to a corporation on December 31, 2010, Baytex sheltered a portion of its income from income taxes by deducting distributions payable to unitholders. Subsequent to conversion, the Company's earnings have been entirely sheltered from current income taxes by a drawdown of tax pools. An increase in deferred income tax expense in 2011 compared to 2010 reflects the cost of consuming these pools. In addition, $109.8 million of the $124.2 million recovery for the year ended December 31, 2010 recovery for the year ended December 31, 2011 relates to the difference between the deferred income tax asset and the cash paid for the acquisition of private entities during the second quarter of 2010.

As at December 31, 2011, net deferred income tax liability was $83.1 million (December 31, 2010 – $6.5 million). The increase relates to the additional liability recognized in the corporate acquisition in the current year of $24.5 million and the impact of accounting income net of adjustments due to decrease in rates and adjustments to opening tax pool balances.

Tax Pools

During 2010 and prior years, Baytex was organized as a mutual fund trust for Canadian income tax purposes. Partially as a result of tax deductions taken for distributions paid to unitholders in 2010 and prior years, no material Canadian cash tax was payable by the Trust, other than the Saskatchewan resource surcharge which is classified as a royalty expense under IFRS.

As a result of the conversion from a trust structure to a corporate legal form on December 31, 2010, Baytex is no longer entitled to a deduction from Canadian taxable income for its distributions, nor will a deduction be available for future dividends. As such, it is likely that cash income tax expense attributable to our Canadian operations will be higher in the future. We have accumulated the Canadian and US tax pools as noted in the table below, which will be available to reduce future taxable income. Our cash income tax liability is dependant upon many factors, including the prices at which we sell our production, available income tax deductions and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and the existing legislation, we expect to become liable for Canadian income taxes in 2013.

The income tax pools detailed below are deductible at various rates as prescribed by law:

($ thousands)		December 31, 2011		December 31, 2010
Canadian Tax Pools				
Canadian oil and natural gas property expenditures	$	264,503	$	271,741
Canadian development expenditures		328,006		292,500
Canadian exploration expenditures		4,253		11,757
Undepreciated capital costs		266,105		184,586
Non-capital losses		712,288		775,727
Financing costs and other		9,824		10,334
Total Canadian tax pools	$	1,584,979	$	1,546,645
US Tax Pools				
Taxable depletion	$	92,871	$	125,628
Intangible drilling costs		87,039		35,000
Tangibles		21,835		3,634
Non-capital losses		90,828		66,530
Total US tax pools	$	292,573	$	230,792

Net Income

Net income for the year ended 2011 was $217.4 million, as compared to $231.6 million for the same period in 2010. This decrease in net income was primarily the result of higher deferred income tax expense, financial derivative losses and depletion and depreciation. This was partially offset by a decrease in share-based compensation and larger gains realized on sale of oil and gas properties compared to 2010.

Other Comprehensive Income

Revenues and expenses of foreign operations are translated to Canadian dollars using average foreign currency exchange rates for the period. Monetary assets and liabilities that form part of the net investment in the foreign operation are translated at the period-end foreign currency exchange rate. Gains or losses resulting from the translation are included in accumulated other comprehensive income (loss) in shareholders'/unitholders' equity and are recognized in net income when there has been a disposal or partial disposal of the foreign operation.

Under IFRS, the Company has elected to deem cumulative currency translation differences as $nil at January 1, 2010. The $3.6 million balance of accumulated other comprehensive loss at December 31, 2011 is the sum of a $10.3 million foreign currency translation loss incurred in 2010 and a $6.8 million foreign currency translation gain for the year ended December 31, 2011 as USD/CAD foreign exchange rates strengthened at December 31, 2011.

FUNDS FROM OPERATIONS, PAYOUT RATIO AND DIVIDENDS OR DISTRIBUTIONS

Funds from operations and payout ratio are non-GAAP measures. Funds from operations represents cash flow from operating activities adjusted for financing costs, changes in non-cash operating working capital and other operating items. Payout ratio is calculated as cash dividends/distributions (net of participation in the Dividend Reinvestment Plan ("DRIP")) divided by funds from operations. Baytex considers these to be key measures of performance as they demonstrate its ability to generate the cash flow necessary to fund dividends and capital investments.

The following table reconciles cash flow from operating activities (a GAAP measure) to funds from operations (a non-GAAP measure):

($ thousands except for %)	Years Ended December 31, 2011	Years Ended December 31, 2010
Cash flow from operating activities	$ 571,860	$ 461,406
Change in non-cash working capital	10,889	11,704
Asset retirement expenditures	10,588	2,829
Financing costs	(44,611)	(34,570)
Accretion on asset retirement obligations	6,185	5,862
Accretion on debentures and long-term debt	572	426
Funds from operations	$ 555,483	$ 447,657
Cash dividends/distributions declared	$ 281,047	$ 243,382
Reinvested dividends/distributions	75,087	53,558
Cash dividends/distributions declared (net of DRIP)	$ 205,960	$ 189,824
Payout ratio	51%	54%
Payout ratio (net of DRIP)	37%	42%

Baytex does not deduct capital expenditures when calculating the payout ratio. Due to the depleting nature of petroleum and natural gas assets, certain levels of capital expenditures are required to minimize production declines. In the petroleum and natural gas industry, due to the nature of reserve reporting, natural production declines and the risks involved in capital investment, it is not possible to distinguish between capital spent on maintaining productive capacity and capital spent on growth opportunities. Should the costs to explore for, develop or acquire petroleum and natural gas assets increase significantly, it is possible that Baytex would be required to reduce or eliminate its dividends in order to fund capital expenditures. There can be no certainty that Baytex will be able to maintain current production levels in future periods. Cash dividends declared, net of DRIP participation, of $206.0 million for the year ended December 31, 2011 were funded through funds from operations of $555.5 million.

The following table compares cash dividends or distributions declared (net of DRIP participation) to cash flow from operating activities and net income:

	Years Ended	
($ thousands)	December 31, 2011	December 31, 2010
Cash flow from operating activities	$ 571,860	$ 461,406
Cash dividends/distributions declared (net of DRIP)	205,960	189,824
Excess of cash flow from operating activities over cash dividends/distributions declared (net of DRIP)	$ 365,900	$ 271,582
Net income	$ 217,432	$ 231,615
Cash dividends/distributions declared (net of DRIP)	205,960	189,824
Excess (shortfall) of earnings over cash dividends/distributions declared (net of DRIP)	$ 11,472	$ 41,791

It is Baytex's long-term operating objective to substantially fund cash dividends and capital expenditures for exploration and development activities through funds from operations. Future production levels are highly dependent upon our success in exploiting our asset base and acquiring additional assets. The success of these activities, along with commodity prices realized, are the main factors influencing the sustainability of our cash dividends. During periods of lower commodity prices or periods of higher capital spending, it is possible that funds from operations will not be sufficient to fund both cash dividends and capital spending. In these instances, the cash shortfall may be funded through a combination of equity and debt financing.

For the year ended December 31, 2011, the Company's net income was in excess of cash dividends declared (net of DRIP participation) by $11.5 million, with net income reduced by $354.4 million for non-cash items. Non-cash items such as depletion and depreciation may not be fair indicators for the cost of maintaining our productive capacity as they are based on historical costs of assets and not the fair value of replacing those assets under current market conditions.

LIQUIDITY AND CAPITAL RESOURCES

We regularly review our liquidity sources as well as our exposure to counterparties, and have concluded that our capital resources are sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations, augmented by our hedging program and existing credit facilities, will provide sufficient liquidity to sustain our operations in the short, medium and long-term. Further, we believe that our counterparties currently have the financial capacities to honor outstanding obligations to us in the normal course of business. We periodically review the financial capacity of our counterparties and, in certain circumstances, we will seek enhanced credit protection from a counterparty.

($ thousands)	December 31, 2011	December 31, 2010
Bank loan	$ 311,960	$ 303,773
Long-term debt[(1)]	302,550	150,000
Working capital deficiency	36,071	52,462
Total monetary debt	$ 650,581	$ 506,235

(1) Principal amount of instruments.

At December 31, 2011, total monetary debt was $650.6 million, as compared to $506.2 million at December 31, 2010. Bank borrowings at December 31, 2011 were $312.0 million, as compared to total credit facilities of $700.0 million.

Our wholly-owned subsidiary, Baytex Energy Ltd., has established credit facilities with a syndicate of chartered banks. On June 14, 2011, Baytex Energy reached agreement with its lending syndicate to amend the credit facilities to (i) increase the amount available under the facilities to $700.0 million (from $650.0 million), (ii) extend the revolving period from 364 days (with a one-year term out following the revolving period) to three years, which is extendible annually for a 1, 2 or 3 year period (subject to a maximum three-year term at any time), and (iii) change the structure of the facilities from reserves-based to covenant-based (with standard commercial covenants for facilities of this nature). Baytex is in compliance with all financial covenants. The credit facilities do not require any mandatory principal payments during the three-year term. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or US funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The credit facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by us and certain of our material subsidiaries. The credit facilities do not include a term-out feature or a borrowing base restriction. In the event that Baytex Energy does not comply with covenants under the credit facilities, our ability to pay dividends to shareholders may be restricted. A copy of the amended and restated credit agreement which establishes the credit facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material Document" on July 22, 2011).

Financing costs for the year ended December 31, 2011 include credit facility amendment fees of $2.3 million ($1.4 million for year ended December 31, 2010). The weighted average interest rate on the bank loan for year ended December 31, 2011 was 3.69% (3.94% for the year ended December 31, 2010).

On February 17, 2011, Baytex issued US$150.0 million principal amount of Series B senior unsecured debentures bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. Net proceeds of this issue were used to repay a portion of the amount drawn in Canadian currency on Baytex Energy's credit facilities. These debentures are unsecured and are subordinate to Baytex Energy's credit facilities.

Pursuant to various agreements with our lenders, we are restricted from paying dividends to shareholders where the dividend would or could have a material adverse effect on us or our subsidiaries' ability to fulfill our respective obligations under the Series A or Series B senior unsecured debentures and Baytex Energy's credit facilities.

Baytex believes that funds from operations, together with the existing credit facilities, will be sufficient to finance current operations, dividends to the shareholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments. The level of dividend is also discretionary, and the Company has the ability to modify dividend levels should funds from operations be negatively impacted by factors such as reductions in commodity prices or production volumes.

Capital Expenditures

Capital expenditures are summarized as follows:

	Years Ended December 31	
($ thousands)	2011	2010
Land	$ 5,219	$ 12,774
Seismic	1,042	186
Drilling and completion	245,093	157,568
Equipment	116,513	61,211
Other	(19)	(120)
Total exploration and development	$ 367,848	$ 231,619
Acquisitions – Corporate	120,006	40,314
Acquisitions – Properties	76,164	22,412
Proceeds from divestitures	(47,396)	(19,033)
Total acquisitions and divestitures	148,774	43,693

Total oil and natural gas expenditures		516,622		275,312
Other plant and equipment, net		1,252		8,237
Total capital expenditures	$	517,874	$	283,549

For the year ended December 31, 2011, Baytex disposed of assets in Kaybob and Dodsland areas which consisted of $9.0 million of oil and gas properties and $2.1 million of exploration and evaluation assets for net cash proceeds of $47.4 million. Gains totaling $36.3 million were recognized in the statements of income and comprehensive income.

Shareholders' Capital

On December 31, 2010, all of the outstanding trust units of the Trust were exchanged for common shares of Baytex on a one-for-one basis in connection with the Corporate Conversion.

Baytex is authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. Baytex establishes the rights and terms of preferred shares upon issuance. As at March 8, 2012, the Company had 118,755,036 common shares and no preferred shares issued and outstanding.

Off Balance Sheet Arrangements

Baytex is not party to any contractual arrangement under which a non-consolidated entity may have any obligation under certain guarantee contracts, a retained or contingent interest in assets transferred to a non-consolidated entity or similar arrangement that serves as credit, liquidity or market risk support to that entity for such assets. Baytex has no obligation under financial instruments or a material variable interest in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company, or engages in leasing, hedging or research and development services with the Company.

Contractual Obligations

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's funds from operations on an ongoing manner. A significant portion of these obligations will be funded with funds from operations. These obligations as of December 31, 2011, and the expected timing of funding of these obligations, are noted in the table below.

($ thousands)	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	$ 225,831	$ 225,831	$ –	$ –	$ –
Dividends payable to shareholders	25,936	25,936	–	–	–
Bank loan[1]	311,960	–	311,960	–	–
Long-term debt[2]	302,550	–	–	150,000	152,550
Operating leases	50,117	5,753	11,884	12,228	20,252
Processing and transportation agreements	5,198	3,238	1,960	–	–
Total	$ 921,592	$ 260,758	$ 325,804	$ 162,228	$ 172,802

(1) The bank loan is a three-year covenant-based revolving loan that is extendible annually for a one, two or three year period (subject to a maximum three-year term at any time). Unless extended, the revolving period will end on June 14, 2014 with all amounts to be re-paid on such date.

(2) Principal amount of instruments.

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

FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Baytex is exposed to a number of financial risks, including market risk, liquidity risk and credit risk. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is managed by Baytex through a series of derivative contracts intended to manage the volatility of its operating cash flow. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default resulting in the Company incurring a loss. Baytex manages credit risk by entering into sales contracts with creditworthy entities and reviewing its exposure to individual entities on a regular basis.

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 Company's control. Included in these risks are the uncertainty of finding new reserves, fluctuations in 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 Baytex competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing Baytex 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. Baytex's ability to increase its production, revenues and funds from operations 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 petroleum 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 Company's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of members of the Board of Directors of Baytex (the "Board"), assists the Board in their annual review of the reserve estimates.

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

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

The Company'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, Baytex 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 of the risk management program is to decrease exposure to market volatility and ensure the Company's ability to finance its dividends and capital program.

Baytex'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 borrowings. The related foreign exchange gains and losses are included in net income.

Baytex is exposed to changes in interest rates as advances under Baytex Energy's credit facilities are based on the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates plus applicable margins.

A summary of the risk management contracts in place as at December 31, 2011 and the accounting treatment of the Company's financial instruments are disclosed in note 23 to the consolidated financial statements for the year ended December 31, 2011.

CRITICAL ACCOUNTING ESTIMATES

A summary of Baytex's significant accounting policies can be found in notes 2 and 3 to the consolidated financial statements. The preparation of the consolidated financial statements in accordance with GAAP requires management to make judgments and estimates that affect the financial results of the Company. The financial and operating results of Baytex incorporate certain estimates including:

- estimated revenues, royalties and operating costs on production as at a specific reporting date but for which actual revenues and costs have not yet been received;
- estimated capital expenditures on projects that are in progress;
- estimated depletion and depreciation that are based on estimates of petroleum and natural gas reserves that Baytex expects to recover in the future;
- estimated fair values of financial derivative contracts that are subject to fluctuation depending upon the underlying commodity prices, interest rates and foreign exchange rates;
- estimated value of asset retirement obligations that are dependant upon estimates of future costs and timing of expenditures; and
- estimated future recoverable value of petroleum and natural gas properties and goodwill.

Baytex has hired individuals who have the skills required to make such estimates and ensures that individuals or departments with the most knowledge of the activity are responsible for the estimates. Further, past estimates are reviewed and compared to actual results, and actual results are compared to budgets in order to make more informed decisions on future estimates.

CHANGES IN ACCOUNTING POLICIES

Current Changes in Accounting Policies

Adoption of International Financial Reporting Standards

IFRS replaced previous GAAP in Canada for financial periods beginning on January 1, 2011. At the transition date, publicly accountable enterprises were required to prepare financial statements in accordance with IFRS. The adoption date of January 1, 2011 requires the restatement, for comparative purposes, of 2010 amounts reported by Baytex, including the opening statement of financial position as at January 1, 2010.

Reconciliations to IFRS from the previously published consolidated financial statements, prepared in accordance with previous GAAP are shown in note 29 to the consolidated financial statements. The accounting policies described in note 3 to the consolidated financial statements set out those policies that have been applied retrospectively and consistently in preparing the consolidated financial statements, except where specific exemptions permitted an alternative treatment upon transition to IFRS in accordance with IFRS 1 (as disclosed in note 29 to the consolidated financial statements).

The following table reconciles Baytex's 2010 previous GAAP results to IFRS for the year ended December 31, 2010:

($ thousands)

Net income – Previous GAAP	$ 177,631
Exploration and evaluation	(24,502)
Depletion and depreciation	63,731
Gain on oil and gas properties	16,227
Accretion on asset retirement obligation	(1,348)
Unit-based compensation	(85,855)
Conversion feature of convertible debentures	(5,118)
Deferred income tax	92,180
Other	(1,331)
Net income – IFRS	$ 231,615

($ thousands)

Funds from operations – Previous GAAP	$ 454,183
Exploration and evaluation	(5,610)
Other	(916)
Funds from operations – IFRS	$ 447,657

Listed below is a summary of the significant effects of the transition from previous GAAP to IFRS:

Exploration and Evaluation

Under previous GAAP, petroleum and natural gas properties included certain exploration and evaluation expenditures incurred within a country-by-country cost centre. Under IFRS, such exploration and evaluation expenditures are recognized as tangible or intangible based on their nature and subject to technical, commercial and management review at least once a year to confirm the continued intent to develop or otherwise extract value from the discovery. When this is no longer the case, the costs are expensed.

Exploration and evaluation assets at January 1, 2010 were deemed to be $124.6 million, being the amount recorded as the undeveloped land balance under previous GAAP. This has resulted in the reclassification from property, plant and equipment to intangible exploration assets of $124.6 million in the opening IFRS statement of financial position.

For the year ended December 31, 2010, Baytex had exploration and evaluation capital expenditures of $37.4 million, corporate acquisitions of $2.5 million, divestitures of $0.1 million, transfers to oil and gas properties of $29.1 million, transfers to expense related to lease expiries of $18.9 million and a decrease due to foreign currency translation of $3.3 million. For the year ended December 31, 2010, Baytex expensed $18.9 million of exploration and evaluation assets related to lease expiries and $5.6 million in direct exploration costs.

Depletion

Upon transition to IFRS, the Company adopted a policy of depleting oil and natural gas properties on a "units of production" basis over proved plus probable reserves on an area basis rather than a cost pool basis under previous GAAP. The depletion policy under previous GAAP was units of production over proved reserves on a country basis.

There was no impact to depletion on transition to IFRS at January 1, 2010. Upon adoption of IFRS, for the year ended December 31, 2010, the change in accounting policy resulted in a decrease in depletion expense of $67.4 million with a corresponding increase in oil and natural gas properties.

Divestiture of Oil and Gas Assets

Previous GAAP utilized the full cost accounting, whereby gains and losses were not recognized upon the divestiture of oil and gas assets unless such a divestiture would alter the rate of depletion by 20% or more. Under IFRS, gains and losses are recognized based on the difference between the net proceeds from the divestiture and the carrying value of the asset disposed. For the year ended December 31, 2010, a gain of $16.2 million was recognized relating to a divestiture of oil and gas assets.

Impairment of Property, Plant and Equipment ("PP&E") Assets

Under IFRS, impairment of PP&E must be calculated at a more detailed level than what was required under previous GAAP. Impairment calculations are performed at the cash generating unit ("CGU") level using the higher of its fair value less costs to sell and its value in use. Baytex uses discounted estimated cash flows from proved plus probable reserves for impairment tests of PP&E. Under previous GAAP, estimated future net cash flows used to assess impairments were not discounted. As such, impairment losses may be recognized earlier under IFRS than under previous GAAP. Impairment losses are reversed under IFRS when there is an increase in the recoverable amount.

Baytex has allocated the PP&E amount recognized under previous GAAP as at January 1, 2010 to the assets at a CGU level using reserve values calculated using the discounted net cash flows. There is no change in the overall net book value of our PP&E as there were no impairments upon transition to IFRS at January 1, 2010.

Asset Retirement Obligations

Under IFRS, Baytex uses a risk free interest rate to discount the estimated fair value of its asset retirement obligations associated with the related oil and natural gas properties. Under previous GAAP, the Company used a credit-adjusted risk free interest rate. A lower discount rate under IFRS will increase the asset retirement obligations. In addition, under IFRS the asset retirement obligations are measured using the best estimate of the expenditure to be incurred and current discount rates at each remeasurement date with the corresponding adjustment to the cost of the related oil and natural gas properties. Existing liabilities under previous GAAP are not re-measured using current discount rates.

Under previous GAAP, the Company's asset retirement obligations were recorded using the credit-adjusted risk free rate of 8.0%. Under IFRS, the Company's asset retirement obligations are recorded using the risk free rate of 3.5% at December 31, 2010 (4.0% at January 1, 2010). Under IFRS, an additional liability of $87.3 million was charged to deficit at January 1, 2010.

For the year ended December 31, 2010, $4.5 million was reclassified to finance costs and an additional accretion expense of $1.4 million on asset retirement has been recognized in net income under IFRS.

Unit-based Compensation

Under previous GAAP, the obligation associated with the Unit Rights Plan is considered to be equity-based and the related unit-based compensation was calculated using the binomial-lattice model to estimate the fair value of the outstanding unit rights at grant date. The exercise of unit rights was recorded as an increase in unitholders' capital with a corresponding reduction in contributed surplus.

Under IFRS, prior to the conversion to a corporation, the obligation associated with the Unit Rights Plan was considered a liability and the fair value of the liability is remeasured at each reporting date and at settlement date. Any changes in fair value are recognized in net income for the period. For periods prior to the conversion to a corporation, remeasuring the fair value of the obligation each reporting period will increase or decrease the unit-based payment liability, unitholders' capital and compensation expense recognized. Upon conversion to a corporation, the outstanding Unit Rights Plan was modified to become the new Share Rights Plan, effectively changing the related classification from liability-settled to equity-settled. The expense recognized from the date of the plan modification over the remainder of the vesting period is determined based on the fair value of the reclassified unit rights at the date of the modification. Upon transition of IFRS at January 1, 2010, an additional unit-based payment liability of $91.6 million and a decrease of $20.4 million in contributed surplus resulted in a corresponding $71.2 million charge to deficit.

Under IFRS, in addition to the January 1, 2010 adjustments discussed above, at December 31, 2010 (immediately prior to the conversion to a corporation) the remeasurement of the liability at reporting date and at settlement date resulted in the recognition of additional unit-based compensation expense of $85.9 million, with a corresponding decrease of $0.3 million in contributed surplus, an increase of $48.0 million in shareholders'/unitholders' equity and an increase of $37.6 million in unit-based payment liability.

Conversion Feature of Convertible Debentures

Under previous GAAP, the convertible debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' or shareholders' equity. The debt portion accreted up to the principal balance at maturity. If the debentures were converted to trust units, a portion of the value of the conversion feature under unitholders' equity was reclassified to unitholders' capital along with principal amounts converted.

Under IFRS, the conversion feature of the convertible debentures has been classified as a financial derivative liability. The financial derivative liability requires a fair value method of accounting and changes in the fair value of the derivative liability are recognized in the statements of income and comprehensive income. If the debentures were converted to trust units, the fair value of the conversion feature under financial derivative liability was reclassified to unitholders'/shareholders' capital along with the principal amounts converted. The impact on adoption to IFRS at January 1, 2010 was an additional liability of $7.4 million, an increase of $33.4 million in unitholders' capital with a corresponding $40.4 million charge to deficit and a decrease of $0.4 million in the conversion feature of convertible debentures.

Under IFRS, for the year ended December 31, 2010, the increase in unitholders'/shareholders' equity of $12.1 million and the increase of $0.4 million in conversion feature of convertible debentures had a corresponding decrease in the $7.4 million liability recorded at January 1, 2010 and a $5.1 million decrease in gain on financial derivatives in net income

Accumulated Other Comprehensive Loss

Under previous GAAP, amounts are composed entirely of currency translation adjustments on self-sustaining foreign operations. Under IFRS, the Company has elected to deem cumulative currency translation differences as $nil at January 1, 2010. At January 1, 2010, this has resulted in an decrease in accumulated other comprehensive loss with a corresponding increase in deficit of $3.9 million.

Deferred Income Taxes

Under IFRS, deferred income taxes are required to be presented as non-current. Upon transition to IFRS, the Company recognized a $27.6 million reduction in the net deferred income tax liability entirely resulting from the tax impact of the adjustments from previous GAAP to IFRS with a decrease to deficit of $25.8 million and a decrease to unitholders' capital of $1.8 million.

In May 2010, Baytex acquired several private entities to be used in its internal financing structure. Under previous GAAP, the excess of amounts assigned to the acquired assets over the consideration paid is classified as a deferred credit. Under IFRS, the deferred credit is derecognized through net income as a deferred income tax recovery. For the year ended December 31, 2010, deferred income tax recovery of $109.8 million was recorded in net income for amounts previously recognized as a deferred credit.

Under IFRS, taxable and deductible temporary differences related to the legal entity of the Trust must be measured using the highest marginal personal tax rate of 39%, as opposed to the corporate tax rates used under previous GAAP, resulting in an increase to the deferred income tax asset of $5.1 million at January 1, 2010. Upon conversion to a dividend-paying corporation on December 31, 2010, the total deferred income tax asset related to the Trust was adjusted to the corporate tax rate of approximately 25% and derecognized through net income on December 31, 2010.

Future Changes in Accounting Policies

Financial Instruments

The International Accounting Standards Board (the "IASB") published IFRS 9, "Financial Instruments" which replaces IAS 39 "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: at amortized cost or fair value.

IFRS 9 is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The adoption of this standard may have an impact on the Company's accounting for financial assets and financial liabilities.

Consolidation, Joint Ventures and Disclosures

In May 2011, the IASB issued new standards, IFRS 10, "Consolidated Financial Statements", IFRS 11, "Joint Arrangements" and IFRS 12, "Disclosure of Interests in Other Entities". IAS 27, "Separate Financial Statements" and IAS 28, "Investments in Associates and Joint Ventures" were amended based on the issuance of IFRS 10, IFRS 11 and IFRS 12. Each of the new and revised standards is effective for annual periods beginning on or after January 1, 2013, with earlier application permitted. The adoption of these standards may have an impact on the consolidated financial statements of the Company.

Consolidated Financial Statements

IFRS 10, "Consolidated Financial Statements" replaces the consolidation guidance in IAS 27, "Consolidated and Separate Financial Statements" by introducing a single consolidation model for all entities based on control, irrespective of the nature of the investee. Under IFRS 10, control is based on whether an investor has: (1) power over the investee; (2) exposure, or rights, to variable returns from its involvement with the investee; and (3) the ability to use its power over the investee to affect the amount of the returns.

Joint Arrangements

IFRS 11, "Joint Arrangements" replaces IAS 31, "Interest in Joint Ventures". The new standard redefines joint operations and joint ventures and requires joint operations to be proportionately consolidated and joint ventures to be equity accounted.

Disclosure of Interests in Other Entities

IFRS 12, "Disclosure of Interests in Other Entities", requires enhanced disclosures about both consolidated entities and unconsolidated entities in which an entity has involvement. The objective of IFRS 12 is to require information so that financial statement users may evaluate the basis of control, any restrictions on consolidated assets and liabilities, risk exposures arising from involvements with unconsolidated structured entities and non-controlling interest holders' involvement in the activities of consolidated entities.

Fair Value Measurement

In May 2011, the IASB issued IFRS 13, "Fair Value Measurement" which replaces the guidance on fair value measurement in existing IFRS accounting literature with a single standard. IFRS 13 is effective for annual periods beginning on or after January 1, 2013 with early application permitted. The adoption of this standard may have an impact on the consolidated financial statements of the Company.

Presentation of Financial Statements

In June 2011, the IASB amended IAS 1, "Presentation of Financial Statements" to require companies preparing financial statements in accordance with IFRS to group together items within other comprehensive income that may be reclassified to the net income section of the income statement. The amendments also reaffirm existing requirements that items in other comprehensive income and profit or loss should be presented as either a single statement or two consecutive statements. The amendment to IAS 1 is effective for annual periods beginning on or after July 1, 2012 with earlier application permitted. The adoption of this amended standard is not expected to have a material impact on the consolidated financial statements of the Company.

SELECTED ANNUAL INFORMATION

($ thousands, except per common share or trust unit amounts)		2011		2010
Petroleum and natural gas sales	$	1,305,814	$	1,003,295
Net income[(1)]	$	217,432	$	231,615
Per common share or trust unit – basic[(1)]	$	1.88	$	2.08
Per common share or trust unit – diluted[(1)]	$	1.83	$	2.01
Total assets	$	2,461,810	$	1,981,023
Total other long-term financial liabilities	$	609,691	$	450,666
Cash dividends or distributions declared per common share or trust unit	$	2.42	$	2.18
Average wellhead prices, net of blending costs	$	61.26	$	53.39
Total production (boe/d)		50,132		44,341

(1) Net income and net income per common share or trust unit is after non-controlling interest related to exchangeable shares.

FOURTH QUARTER OF 2011

For a discussion and analysis of our operating and financial results for the three months ended December 31, 2011, please see our Management's Discussion and Analysis for the three months and year ended December 31, 2011 dated March 13, 2012, which is incorporated by reference into this MD&A and is accessible on SEDAR at www.sedar.com.

2012 GUIDANCE

We have set a 2012 exploration and development capital budget of $400 million, which is designed to generate production levels at an average annual rate of 54,000 to 55,000 boe/d.

We view 2011 as the year in which we completed our shift from a predominantly income-focused model as a trust to a growth-and-income model in our new corporate era. Our 2012 capital program reflects the continuation and advancement of the growth-and-income model. Based on the mid-point of the production guidance ranges for 2011 and 2012, our 2012 plan reflects an organic production growth rate of 8% based on oil-equivalent production, and 11% for oil production. Our 2012 production mix is forecast to be approximately 69% heavy oil, 16% light oil and natural gas liquids and 15% natural gas, based on a 6:1 natural gas-to-oil equivalency.

Approximately 60% of our 2012 capital budget will be invested in our heavy oil operations, with the majority being directed to cold primary horizontal well development at Seal in the Peace River Oil Sands. This budget also includes funding to begin drilling and facility construction on a second module of commercial thermal development at Seal. The second thermal module is planned as a 15-well cyclic steam stimulation (CSS) project. Subject to receipt of regulatory approvals, we expect to commence development of this project in the fourth quarter of 2012 and be completed in the first quarter of 2013. Our capital budget for the Lloydminster area is directed primarily at cold drilling, with horizontal wells comprising the majority of drilling capital. The balance of our capital program will be directed primarily towards light oil development, with the two largest projects being the Bakken/Three Forks in North Dakota and the Viking in southeast Alberta.

ENVIRONMENTAL REGULATION AND RISK

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities.

Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs.

Climate Change Regulation

In December 2002, the Government of Canada ratified the Kyoto Protocol ("Kyoto Protocol"), which requires a reduction in greenhouse gas ("GHG") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005, although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol. In December 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "Action Plan") which set forth a plan for regulations to address both GHG emissions and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "Updated Action Plan"). The Updated Action Plan outlines emissions intensity-based targets which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets. Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In January 2012, representatives from the Government of Canada indicated that flexibility may be introduced into the proposed regulations which would allow for Provinces to set their own emissions targets, as long as they have rules in place that would achieve equivalent reductions. As a result of ensuring consistency with the United States and the possibility that emissions targets will be Province specific, it is unclear to what extent, if any, the proposals contained in the Updated Action Plan will be implemented.

In addition to federal commitments and legislation, Province specific legislation also imposes GHG emission standards and regulations which may impact Baytex and its operations and financial condition. The implementation of strategies for reducing GHG, whether to meet the goals of the Copenhagen Accord, the Cancun Agreements, federal or provincial regulations, or otherwise, could have a material impact on the nature of oil and natural gas operations, including those of Baytex. Given the evolving nature of the debate related to climate changes and the regulation of GHG, it is not possible to predict the impact of those requirements, or future requirements, on Baytex and its operations and financial condition.

Further information regarding environmental and climate change regulation is contained in our Annual Information Form for the year ended December 31, 2011 under the "Industry Conditions – Climate Change Regulation" section.

DISCLOSURE CONTROL AND PROCEDURES

As of December 31, 2011, an evaluation was conducted of the effectiveness of the Baytex's "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in

Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer. Based on that evaluation, the President and Chief Executive Officer and the Chief Financial Officer concluded that the Baytex's disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that the Baytex files or submits under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to the Company's management, including the President and Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

It should be noted that while the President and Chief Executive Officer and the Chief Financial Officer believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the Baytex's disclosure controls and procedures 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.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management is responsible for establishing and maintaining adequate internal control over financial reporting for the Baytex. "Internal control over financial reporting" (as defined in the United States by Rules 13a-15(f) and 15d-15(f) under the Exchange Act and in Canada by NI 52-109) is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of Baytex's financial statements for external reporting purposes in accordance with Canadian GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Additionally, projections of any evaluations of effectiveness to future periods are subject to risk that controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with Baytex's policies and procedures. Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2011 based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2011. The effectiveness of the Baytex's internal control over financial reporting as of December 31, 2011 has been audited by Deloitte & Touche LLP, as reflected in their report for 2011.

No changes were made to our internal control over financial reporting during the year ended December 31, 2011.

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to: crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our business strategies, plans and objectives; our ability to fund our capital expenditures and dividends on our common shares from funds from operations; our ability to utilize our tax pools to reduce or potentially eliminate our taxable income for the initial period post-conversion; the timing of payment of Canadian income taxes; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; funding sources for our cash dividends and capital program; the timing of funding our financial obligations; the existence, operation, and strategy of our risk management program; the impact of the

adoption of new accounting standards on our financial results; our exploration and development capital expenditures for 2012; our average production rate for 2012; our production growth rates for 2012; our production mix for 2012; the allocation of our exploration and development capital expenditures for 2012; our heavy oil resource play at Seal, including the timing of completing a 15-well cyclic steam stimulation project; and the impact of new environmental and climate change regulations on our operations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

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

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: fluctuations in market prices for petroleum and natural gas; fluctuations in foreign exchange or interest rates; general economic, market and business conditions; stock market volatility and market valuations; changes in income tax laws; industry capacity; geological, technical, drilling and processing problems and other difficulties in producing petroleum and natural gas reserves; uncertainties associated with estimating petroleum and natural gas reserves; liabilities inherent in oil and natural gas operations; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; risks associated with oil and natural gas operations; changes in royalty rates and incentive programs relating to the oil and natural gas industry; changes in environmental and other regulations; incorrect assessments of the value of acquisitions; the failure to obtain the necessary regulatory and other approvals on planned timelines; and other factors, many of which are beyond the control of Baytex. These risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2011, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Anthony W. Marino, certify that:

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

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

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

4. The issuer's other certifying officer 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

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

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. 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

   d. 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 and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses 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 internal control over financial reporting.

BAYTEX ENERGY CORP.

/s/ ANTHONY W. MARINO

Name: Anthony W. Marino
Title: President and Chief Executive Officer

Dated: March 15, 2012

Exhibit 99.5

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, W. Derek Aylesworth, certify that:

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

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

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

4. The issuer's other certifying officer 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)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

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

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. 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

    d. 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 internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses 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 internal control over financial reporting.

BAYTEX ENERGY CORP.

/s/ W. DEREK AYLESWORTH

Name: W. Derek Aylesworth
Title: Chief Financial Officer

Dated: March 15, 2012

Exhibit 99.6

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Baytex Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Anthony W. Marino, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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 presents, in all material respects, the financial condition and results of operations of the Company.

BAYTEX ENERGY CORP.

/s/ ANTHONY W. MARINO

Name: Anthony W. Marino
Title: President and Chief Executive Officer

Dated: March 15, 2012

Exhibit 99.7

**CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the Annual Report of Baytex Energy Corp. (the "Company") on Form 40-F for the fiscal year ended December 31, 2011, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, W. Derek Aylesworth, certify, pursuant to 18 U.S.C. section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that to the best of my knowledge:

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 presents, in all material respects, the financial condition and results of operations of the Company.

BAYTEX ENERGY CORP.

/s/ W. DEREK AYLESWORTH

Name: W. Derek Aylesworth
Title: Chief Financial Officer

Dated: March 15, 2012

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

We consent to the incorporation by reference in Registration Statements No(s). 333-163289 and 333-171568 on Form S-8; No. 333-171866 on Form F-3; and No. 333-175796 on Form F-10 of Baytex Energy Corp. ("Baytex"); and Registration Statement No. 333-175801 on Form F-3 of Baytex Energy USA Ltd.; and to the use of our reports dated March 13, 2012 relating to the consolidated financial statements of Baytex and its subsidiaries and the effectiveness of Baytex's internal control over financial reporting appearing in this Annual Report on Form 40-F of Baytex for the year ended December 31, 2011.

/s/ Deloitte & Touche LLP
Independent Registered Chartered Accountants
March 15, 2012
Calgary, Canada

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

We refer to our report dated March 7, 2012 and effective December 31, 2011, evaluating the petroleum and natural gas reserves attributable to Baytex Energy Corp. and its affiliates, which is entitled "Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2011)" (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.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2011 dated March 15, 2012, 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.

SPROULE ASSOCIATES LIMITED

/s/ CAMERON P. SIX

Cameron P. Six, P. Eng.
Vice-President, Engineering and Partner

Calgary, Alberta, Canada
March 15, 2012