# 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, 2014
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, Inc.**
**2300, 1200 Smith Street**
**Houston, Texas 77002**
**(713) 402-1920**
(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: 168,107,249

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 Registrant and Baytex Energy USA Ltd. (File Nos. 333-191762 and 333-191764).

## 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, 2014, 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, 2014, including the report of its Independent Registered Public Accounting Firm 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, 2014, 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, 2014, 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.

The Registrant acquired 100% of the ordinary shares of Aurora Oil & Gas Limited ("Aurora") on June 11, 2014. The Registrant has not had sufficient time to appropriately assess the disclosure controls used by Aurora and integrate them with those of the Registrant.

***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, 2014, filed as Exhibit 99.2 to this Annual Report on Form 40-F, and is incorporated herein by reference. As a result, as permitted by the Sarbanes-Oxley Act and applicable rules related to business acquisitions, the previous Aurora operations have been excluded from the Registrant's annual assessment of internal controls over financial reporting. Aurora's financial statements constitute 67 percent and 58 percent of net and total assets, respectively, 23 percent of net revenues and 304 percent of net loss as reported in the Registrant's Audited Consolidated Financial Statements as of and for the year ended December 31, 2014. The Registrant is in the process of integrating operations and will be expanding its internal control over financial reporting compliance regime to include the acquired Aurora assets over the next year.

***D. Attestation Report of Independent Registered Public Accounting Firm***

The Attestation Report of the Registrant's Auditor is included in the Report of Independent Registered Public Accounting Firm that accompanies the Registrant's Audited Consolidated Financial Statements for the year ended December 31, 2014, 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, 2014, 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 Registrant'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, 2014, 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.baytexenergy.com.

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, 2014, 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, 2014, 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 Registrant has a separately designated standing audit committee established in accordance with Section 3(a)(58)(A) of the Exchange Act. The Registrant's Audit Committee members consist of Mr. N. Dargan, Mr. G. Melchin and Ms. M. Peters.

## UNDERTAKING

The 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 the 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 9, 2015.

**BAYTEX ENERGY CORP.**

By: /s/ RODNEY D. GRAY

Name: Rodney D. Gray
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, 2014. |
| 99.2 | Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2014 together with the Auditors' Report thereon.(1) |
| 99.3 | Management's Discussion and Analysis of the operating and financial results of the Registrant for the year ended December 31, 2014.(1) |
| 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 LLP, Independent Registered Public Accounting Firm. |
| 99.9 | Consent of Sproule Unconventional Limited, independent engineers |
| 99.10 | Consent of Ryder Scott Company, L.P., independent engineers |
| 99.11 | Consent of McDaniel & Associates Consultants Ltd., independent engineers |
| 99.12 | Supplemental Disclosures about Extractive Activities — Oil and Gas (unaudited) |

(1) Incorporated by reference from Form 6-K filed on March 5, 2015

Use these links to rapidly review the document


**EXHIBIT 99.1**

BAYTEX

ENERGY CORP.

# ANNUAL INFORMATION FORM

## 2014

## MARCH 9, 2015

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## SELECTED TERMS

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

***Entities***

**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 and Baytex Holdings Limited Partnership.

**Baytex USA** means Baytex Energy USA, Inc.

**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 Entity** 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.

***Independent Engineering***

**Baytex Reserves Report** means, collectively, (i) the report prepared by Sproule dated February 27, 2015 entitled "*Consolidation of the P&NG Reserves of Baytex Energy Corp. Evaluated by Sproule Unconventional Limited and Ryder Scott Company L.P. (As of December 31, 2014)*", which is a consolidation of (a) the report of Sproule dated February 17, 2015 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. in Canada (As of December 31, 2014)*" and (b) the report of Ryder Scott dated January 31, 2015 entitled "*Baytex Energy Corp. Summary Report Estimated Future Reserves and Income Attributable to Certain Leasehold Interests NI 51-101 Forecast Economic Parameters Canadian Currency As of December 31, 2014*" and (ii) the report prepared by Ryder Scott dated February 6, 2015 in respect of Ryder Scott's audit of the possible reserves associated with our Eagle Ford assets.

**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.

**Ryder Scott** means Ryder Scott Company, L.P., independent petroleum consultants of Houston, Texas.

**Sproule** means Sproule Unconventional Limited, independent petroleum consultants of Calgary, Alberta.

***Securities and Other Terms***

**2020 Aurora Notes** means the 7.50% senior unsecured notes due April 1, 2020 issued by Baytex USA (formerly Aurora Oil & Gas, Inc.) pursuant to Debt Indenture #3 of which US$6.4 million was outstanding as at March 1, 2015.

**2021 Debentures** means the 6.75% series B senior unsecured debentures due February 17, 2021 issued by Baytex pursuant to Debt Indenture #1 of which US$150 million was outstanding as at March 1, 2015.

**2021 Notes** means the 5.125% senior unsecured notes due June 1, 2021 issued by Baytex pursuant to Debt Indenture #2 of which US$400 million was outstanding as at March 1, 2015.

**2022 Debentures** means the 6.625% series C senior unsecured debentures due July 19, 2022 issued by Baytex pursuant to Debt Indenture #1 of which $300 million was outstanding as at March 1, 2015.

**2024 Notes** means the 5.625% senior unsecured notes due June 1, 2024 issued by Baytex pursuant to Debt Indenture #2 of which US$400 million was outstanding as at March 1, 2015.

**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, which are consistent with International Financial Reporting Standards as issued by the International Accounting Standards Board.

**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 the revolving extendible unsecured credit facilities that we have established with our bank lending syndicate consisting of (i) a $50 million operating loan and a $950 million syndicated loan for us and (ii) a US$200 million syndicated loan for Baytex USA, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). Unless extended by the lenders, the Credit Facilities will mature on June 4, 2018.

**Debt Indenture #1** means the amended and restated trust indenture among us, as issuer, certain of our subsidiaries, as guarantors, and Valiant Trust Company, as indenture trustee, dated January 1, 2011, as supplemented by supplemental indentures dated February 17, 2011, February 18, 2011, July 19, 2012, December 19, 2012, June 4, 2014, June 11, 2014 and July 25, 2014.

**Debt Indenture #2** means the indenture among us, as issuer, certain of our subsidiaries, as guarantors, and Computershare Trust Company, N.A., as indenture trustee, dated June 6, 2014, as supplemented by supplemental indentures dated June 11, 2014 and July 25, 2014.

**Debt Indenture #3** means the indenture among Aurora Oil & Gas, Inc. (now Baytex USA), as issuer, certain of its affiliates, as guarantors, and U.S. National Bank Association, as indenture trustee, dated March 21, 2013, as supplemented by supplemental indentures dated December 6, 2013, April 25, 2014 and May 5, 2014.

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

**SAGD** means steam-assisted gravity drainage.

**Senior Notes** means, collectively, the 2021 Debentures, the 2021 Notes, the 2022 Debentures and the 2024 Notes.

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

**Trust Indenture** means the third amended and restated trust indenture between 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.

| | |
|---|---|
| API | the measure of the density or gravity of liquid petroleum products derived from a specific gravity |
| $ Million | millions of dollars |
| $000s | thousands of dollars |

## CONVERSIONS

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

**ABBREVIATIONS**

| 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, but not limited to: our business strategies, plans and objectives; our ability to grow our reserves base and maintain or add to production levels through exploration and development activities complemented by strategic acquisitions; our petroleum and natural gas reserves, including the volume thereof and the present value of the future net revenue to be derived therefrom and the potential of the Austin Chalk and Upper Eagle Ford formations of our Eagle Ford assets; the estimates of contingent resources for our oil resource plays at Peace River, Northeast Alberta and the Gemini SAGD project, including the volume thereof; development plans for our properties, including number of potential drilling locations, number of wells to be drilled in 2015, initial production rates from new wells and recovery factors; the development potential of our oil sands leases at Angling Lake (Cold Lake) for both primary (cold) and thermal recovery methods; our plans for a SAGD project at Gemini (Angling Lake (Cold Lake)); our plan to expand the waterflood at Carruthers in 2016 and beyond; our SAGD project at Kerrobert, including the number of potential well pair and infill well drilling locations and well costs; our plan for a commercial waterflood project at Tangleflags; our heavy oil resource play at Peace River, including the resource potential of our undeveloped land, initial production rates from new wells under primary recovery methods and the ability to recover incremental reserves using waterflood recovery; our thermal operations at Cliffdale, including our assessment of the production and steam-oil ratio performance of Pad 1, the timing of commencing steam injection at Pad 2, and plans to expand the program and build a central processing facility and our expectation of lower operating costs as a result of gas conservation; our expectations regarding undeveloped lease expiries; our expectation regarding the payment of cash income taxes in 2015; our future abandonment and reclamation liabilities; our working interest production volume for 2015; the existence, operation and strategy of our risk management program; our ability to extend our Credit Facilities; 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.

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, probable undeveloped reserves and possible 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 reserves 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 for our operating activities; 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; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Actual results achieved 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; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; 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; a downgrade of our credit ratings; risks associated with properties operated by third parties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; 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 large projects or expansion of our activities; risks related to heavy oil projects; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; 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 our control.

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.

The above summary of assumptions and risks related to forward-looking information in this Annual Information Form has been provided in order to provide Shareholders and potential investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes. There is no representation by us that actual results achieved during the forecast period will be the same in whole or in part as those forecast and we do 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 Resources**

This Annual Information Form contains estimates of the volumes of the "contingent resources" for our oil resource plays in the Bluesky in the Peace River area of Alberta, the Mannville group in Northeast Alberta and Gemini SAGD project at Angling Lake (Cold Lake), Alberta, as of December 31, 2014. These estimates were prepared by independent qualified reserves evaluators.

"Contingent resources" are not, and should not be confused with, petroleum and natural gas reserves. "Contingent resources" are defined in the COGE 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 resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage."

The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

A range of contingent resources 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 in the low estimate have the highest degree of certainty (a 90% confidence level) that the actual quantities recovered will 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 in the best estimate have a 50% confidence level that the actual quantities recovered will 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 equal or exceed the high estimate. Those resources in the high estimate 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 resources as reserves consist of: preparation of firm development plans, including determination of the specific scope and timing of the project; project sanction; stakeholder and regulatory approvals; access to required services and field development infrastructure; oil prices and price differentials between light, medium and heavy gravity crude oils; 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 resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exist in the quantities predicted or estimated and that the resources can be profitably produced in the future.

The recovery and resource estimates provided herein are estimates only. Actual contingent resources (and any volumes that may be reclassified as reserves) and future production from such contingent resources 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 and may not be comparable to similar measures used by other companies. 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 operating and financial results for the year ended December 31, 2014*" which is accessible on the SEDAR website at *www.sedar.com*.

**New York Stock Exchange**

As a Canadian foreign private 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 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 from such standards in any significant way.

**Access to Documents**

Any document referred to in this Annual Information Form 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 2400, 525 - 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1.

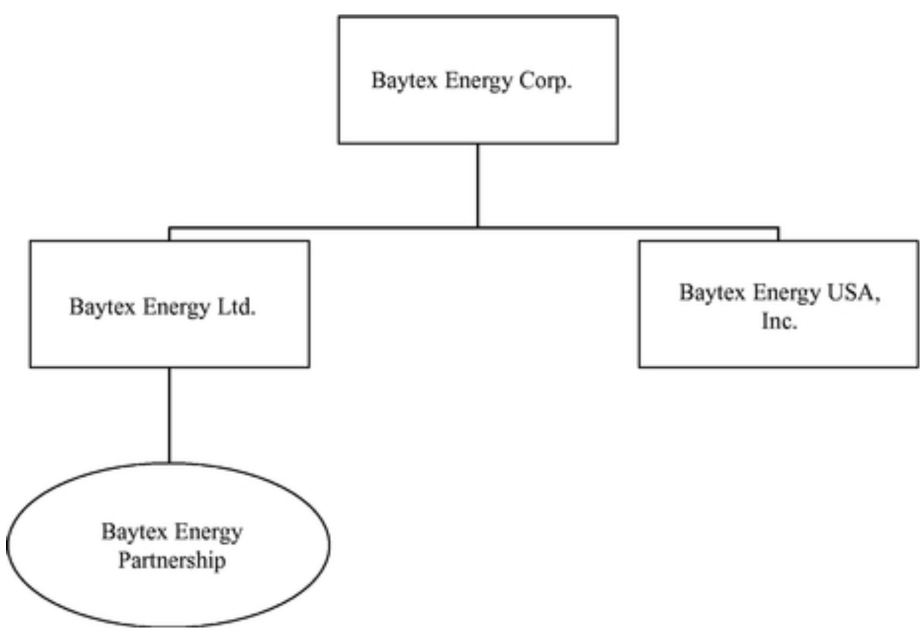
### Inter-Corporate Relationships

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 material subsidiaries either, direct and indirect, as at the date hereof.

| | Percentage of voting securities (directly or indirectly) | Jurisdiction of Incorporation/ Formation |
|---|---|---|
| Baytex Energy Ltd. | 100% | Alberta |
| Baytex Energy USA, Inc. | 100% | Delaware |
| Baytex Energy Partnership | 100% | Alberta |

### Our Organizational Structure

The following simplified diagram shows the inter-corporate relationships among us and our material subsidiaries as of the date hereof.



## GENERAL DEVELOPMENT OF OUR BUSINESS

### History and Development

On May 22, 2012, we completed the sale of our non-operated interests in North Dakota for US$312 million (net of adjustments). The disposed assets included approximately 950 boe/d of Bakken light oil production and 149,700 (50,400 net) acres of land, of which approximately 24% was developed.

On July 19, 2012, we completed a public offering of $300 million principal amount of 6.625% series C senior unsecured debentures due July 19, 2022. The net proceeds of the offering were used to repay existing indebtedness under the Credit Facilities and to fund the redemption effective August 26, 2012 of our 9.15% series A senior unsecured debentures due August 26, 2016 (principal amount $150 million).

On October 3, 2012, we acquired a 100% working interest in 46 sections of undeveloped oil sands leases in the Angling Lake (Cold Lake) area of Northern Alberta. The lands are proximal to our existing Cold Lake heavy oil assets and are prospective for both cold and thermal development. Regulatory approval has been obtained for the construction and operation of a two-stage bitumen recovery scheme using steam-assisted gravity drainage on approximately 2.5 sections of the acquired lands. The total consideration for the acquisition was $120 million.

On January 31, 2013, we completed the sale of our Viking land rights in the Kerrobert area of southwest Saskatchewan for $42.0 million. The disposed assets included approximately 100 boe/d of production, 22,000 net acres of land and 1.5 million boe of proved plus probable reserves (4% proved developed producing) as at December 31, 2012.

On June 11, 2014, we acquired all of the ordinary shares of Aurora Oil & Gas Limited ("**Aurora**") for $4.20 (Australian dollars) per share by way of a scheme of arrangement under the Corporations Act 2001 (Australia) (the "**Arrangement**"). The total purchase price for Aurora was approximately $2.8 billion, including the assumption of $955 million of indebtedness and $54.6 million of cash. Aurora's primary asset consisted of 22,200 net contiguous acres in the Sugarkane area located in South Texas in the core of the liquids-rich Eagle Ford shale. The acquisition added an estimated 166.6 Mboe of proved and probable reserves. Aurora's gross production during the three months ended March 31, 2014 was approximately 28,600 boe/d of predominantly light, high-quality crude oil.

To finance the acquisition of Aurora, we issued 38,433,000 subscription receipts at $38.90 each on February 24, 2014, raising gross proceeds of approximately $1.5 billion. The subscription receipts were converted to Common Shares on June 11, 2014. We also entered into an agreement with a Canadian chartered bank for the provision of the Credit Facilities, which provided unsecured revolving credit facilities of approximately $1.2 billion (to replace the $850 million revolving credit facilities of Baytex Energy Ltd.), and a new two-year $200 million unsecured term loan. The Credit Facilities became available upon closing of the Arrangement and were used to finance a portion of the purchase price.

On June 6, 2014, we completed a private placement of US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 and US$400 million of 5.625% notes due June 1, 2024. Approximately US$730 million of the net proceeds of the offering were used to finance the purchase and cancellation of US$650.7 million principal amount of senior unsecured notes of Aurora with the remainder used for general corporate purposes.

In September, 2014, we completed the sale of our assets in North Dakota for US$330.5 million. The disposed assets produced approximately 3,200 boe/d in the second quarter of 2014 and included 53.5 million boe of proved plus probable reserves (81% oil and NGL) as at December 31, 2013. A portion of the sale proceeds were used to repay the $200 million unsecured term loan that had been drawn to partially finance the acquisition of Aurora and such loan was cancelled.

In the fourth quarter of 2014, we disposed of certain non-core assets in Canada with associated production of approximately 1,250 boe/d realizing net proceeds of approximately $45.7 million.

**Significant Acquisitions**

During the year ended December 31, 2014, the only acquisition that we completed for which disclosure was required under Part 8 of National Instrument 51-102 was the corporate acquisition of Aurora Oil & Gas Limited. We filed a Business Acquisition Report for this acquisition, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on July 30, 2014). For a brief summary of this acquisition, see "— *History and Development*".

## 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, reputation, financial condition, results of operations and cash flow could be materially and adversely affected, which may reduce or restrict our ability to pay dividends to Shareholders and may materially affect the market price of our securities. Additional risks and uncertainties not currently known to us that we currently view as immaterial may also materially and adversely affect us. 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; substantial or extended declines in oil and natural gas prices will adversely affect us***

Our financial condition is substantially dependent on, and highly sensitive to the prevailing prices of crude oil and natural gas. Since June 30, 2014, crude oil prices have declined substantially. Low prices for crude oil and natural gas could have a material adverse effect on our operations, and financial condition and the value and amount of our reserves.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the foreign supply of crude oil, the price of foreign imports, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when the commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

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 supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

The price for crude oil declined significantly in the latter half of 2014 and into 2015. A prolonged period of low and/or volatile commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due, it could also result in a delay or cancellation of existing or future drilling, development or construction programs, a reduction or elimination of dividends on our Common Shares, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

Our reserves as at December 31, 2014 are estimated using forecast prices and costs as set forth under "*Description of Our Business and Operations — Statement of Reserves Data and Other Oil and Natural Gas Information — Pricing Assumption*". These prices are substantially above current crude oil and natural gas prices. If crude oil and natural gas prices stay at current levels, our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and underdeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

We conduct assessments of the carrying value of our assets in accordance with Canadian GAAP. If crude and natural gas forecast prices decline, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

***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. 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.

Our production is primarily transported through various pipelines and by rail. 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 prices being realized by Canadian producers compared with the WTI price for crude oil. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry in Canada and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that investment in pipelines which would result in additional long-term take-away capacity will be made by applicable third party pipeline providers or that any requisite applications will receive regulatory approval. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur. There is also no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather or derailment and could adversely impact our crude oil sales volumes or the price received for our product. Our product or railcars may be involved in a derailment or incident that results in legal liability or reputational harm. In addition, if new regulation is introduced, including but not limited to the potential amendment of the safety standards for tank cars used to transport crude oil, it could adversely affect our ability to ship crude oil by rail or the economics associated with rail transportation.

A portion of 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.

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

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. 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 ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in our securities in particular and our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

***Failure to renew our Credit Facilities or failure to comply with the covenants in the agreements governing our debt could adversely affect our financial condition***

Our existing Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. We currently have Credit Facilities in the amount of $1.0 billion plus US$200 million. 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. In the event that the Credit Facilities are not extended before June 2018, indebtedness under the Credit Facilities will be repayable at that time. In addition, we are required to repay our existing Senior Notes and the 2020 Aurora Notes on maturity, see "*Description of Capital Structure — Senior Notes*".

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. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms.

We are required to comply with covenants under the Credit Facilities and the Senior Notes. 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. If we are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, our lenders may receive judgment and have an unsecured claim on our properties. The proceeds of any sale would be applied to satisfy amounts owed to the creditors. Only after the proceeds of that sale were applied towards the debt would the remainder, if any, be available for dividends.

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 Senior Notes may also limit dividends. There can be no assurance that the amount of our Credit Facilities 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 are not the operator of a substantial majority of the drilling locations in our Eagle Ford acreage and, therefore, we will not be able to control the timing of development, associated costs, or the rate of production on that non-operated acreage.***

Marathon Oil EF LLC ("**Marathon Oil**"), a wholly-owned subsidiary of Marathon Oil Corporation (NYSE: MRO), is the operator of a substantial majority of our Eagle Ford acreage and we will be reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interests and the collective best interests of all of the working interest owners of this acreage, which may not be in our best interests. We have limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and drilling locations and schedules. The success and timing of development activities operated by Marathon Oil will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- Marathon Oil's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets and reduce the amount of cash available to distribute to Shareholders. If we are not willing or are unable to fund our capital expenditure requirements relating to our Marathon Oil-operated drilling locations, our interests in our drilling locations may be diluted or forfeited.

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

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 and Texas, all of which should be carefully considered by investors in the oil and gas industry. See "*Industry Conditions*". 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.

The oil and gas 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 (including restrictions on production) and possibly expropriation or cancellation of contract rights.

We 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. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, new projects or the expansion of existing projects may be dependent on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us, or at all, or that such additional water will in fact be available to divert under such licenses.

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. In a limited number of areas hydraulic fracturing has been banned by government pronouncement or pending public review or is subject to moratoria or further limitation while regulators study the practice. As at the date hereof, we did not own any properties in the affected areas. 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.

Other government controls, legislation or regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or 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 effect on us. In addition, failure to comply with government controls, legislation or 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.

***The oil and gas industry is highly regulated and changes in environmental, health and safety controls, legislation or regulations may impose restrictions, costs or other liabilities on our business which may adversely affect our results of operations or financial condition***

All phases of our operations are subject to environmental, health and safety regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, territorial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety aspects of our operations, the spill, release or emission of materials into the environment or otherwise relating to environmental protection. Environmental regulations require that wells, facility sites and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. Alberta, Saskatchewan and British Columbia have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes in the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted.

Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties and failure to comply with environmental regulations may result in the imposition of administrative, civil and criminal penalties 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. Although it is not expected that the costs of complying with environmental regulations will have a material adverse effect on our financial condition or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and gas industry generally could reduce demand for crude oil and natural gas, result in stricter standards and enforcement, larger penalties 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*".

The development of Alberta's oil sands has received considerable attention in recent public commentary on the subjects of environmental impact, climate change and greenhouse gas emissions. Despite the fact that much of the focus is on bitumen mining operations and not in-situ production, public concerns about greenhouse gas emissions and water and land use practices in oil sands developments may, directly or indirectly, impair the profitability of our current oil sands projects, and the viability of future oil sands projects, by creating significant regulatory uncertainty leading to uncertain economic modeling of current and future projects and delays relating to the sanctioning of future projects. Negative consequences which could arise as a result of changes to the current regulatory environment include, but are not limited to, extraordinary environmental and emissions regulation of current and future projects by governmental authorities, which could result in changes to facility design and operating requirements, thereby potentially increasing the cost of construction, operation and abandonment. In addition, legislation or policies that limit the purchase of crude oil or bitumen produced from the oil sands may be adopted in domestic and/or foreign jurisdictions, which, in turn, may limit the world market for this crude oil and reduce its price.

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

***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 effect 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 revenues and our ability to maintain dividends to Shareholders in the future. Starting in mid-2014, a substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as a large portion of our Senior Notes are denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. 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***

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. We also use derivative instruments in various operational markets to optimize our supply or production chain. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and may also result in royalties being paid on a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. In addition, our current derivative contracts provide a substantial benefit to us during this period of low crude oil prices. These benefits will only be realized for the period and for the commodity quantities in those contracts. Assuming that the futures market for crude oil remains at current pricing levels, additional hedges at prices at or near such prior prices would not be available, which will adversely impact our revenues. For more information in relation to our commodity hedging program, see "*Description of Our Business and Operations — Statement of Reserves Data and Other Oil and Natural Gas Information — Other Oil and Gas Information — Forward Contracts*".

***Our financial performance is significantly affected by the cost of developing and operating our assets.***

Our development and operating costs are affected by a number of factors including, but not limited to: inflationary price pressure, scheduling delays, failure to maintain quality construction standards, and supply chain disruptions, including access to skilled labour. Natural gas, electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating and other costs that are susceptible to significant fluctuation.

***Our ability to add to our oil 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 oil 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. Completion of a well does not assure a profit on the investment. Drilling hazards or environmental liabilities or damages could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays or failure 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.

***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***

We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, such reassessment may have an impact on current and future taxes payable.

In 2014, the Canada Revenue Agency advised us that it is proposing to reassess certain of our subsidiaries to deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2013. If the non-capital loss deductions that have been claimed to-date are disallowed, it would result in an estimated liability of approximately $57 million and a reduction of approximately $262 million of non-capital losses for subsequent taxation years.

Income tax laws, other laws or government incentive programs relating to the oil and gas industry 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.

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 oil and natural gas reserves and contingent resources, including many factors beyond our control***

The reserves estimates included in this Annual Information Form are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves.

The contingent resources 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 resources. In addition, there are contingencies that prevent contingent resources from being classified as reserves. There is no certainty that it will be commercially viable to produce any portion of the contingent resources. 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 hazards. We have not insured and cannot fully insure against all risks related to our operations***

Our crude oil and natural gas operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) the operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; blowouts; fires; explosions; equipment failures and other accidents; gaseous leaks; uncontrollable or unauthorized flows of crude oil, natural gas or well fluids; migration of harmful substances; oil spills; corrosion; adverse weather conditions; pollution; acts of vandalism and terrorism; and other adverse risks to the environment.

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 on our business, financial condition, results of operations, prospects and our ability to maintain dividends to Shareholders.

***We are subject to a number of additional business risks which could adversely affect our income and financial condition***

Our business involves many operating risks related to acquiring, developing and exploring for oil and natural gas which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation and interruptions; reservoir performance and technical challenges; partner risks; competition; technology; land claims; our ability to hire and retain necessary skilled personnel; the availability of drilling and related equipment; information systems; seasonality and access restrictions; timing and success of integrating the business and operations of acquired assets and companies; phased growth execution; risk of litigation, regulatory issues, increases in government taxes and changes to royalty or mineral/severance tax regimes; and risk to our reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

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

We have a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. Our ability to complete projects is dependent on general business and market conditions as well as other factors beyond our control, including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity and rail terminals, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment and supplies, and availability of processing capacity.

***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 uneconomic, which could have an adverse 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; the cost to transport sales products; and the cost to dispose of certain by-products.

***The implementation of strategies for reducing greenhouse gases may impose restrictions or costs on our business which may adversely affect our financial condition***

Our exploration and production facilities and other operations and activities associated with the exploration and production of crude oil and natural gas emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation or regulations that is enacted in jurisdictions where we have operations. A number of federal, provincial state and multi-state governments have announced intentions to regulate greenhouse gases and certain air pollutants. These governments are currently developing the regulatory and policy frameworks to deliver on their announcements. In most cases, there are few technical details regarding the implementation and coordination of these plans to regulate emissions. However, the Canadian federal government has announced that it will align greenhouse gas emission reduction targets with the U.S. The Canadian federal government has taken a sector-specific approach, and while progress has been made working with industry and the provinces on the development of oil and gas sector-specific regulations, the Canadian federal government has not committed to a definitive timeline for the implementation or release of legislation. As it remains unclear what approach the U.S. Congress will take, or when, it is also unclear whether the U.S. Congress will implement economy-wide greenhouse gas emission legislation or a sector-specific approach, and what type of compliance mechanisms will be available to certain emitters. In the absence of such Congressional climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs that typically require major sources of greenhouse gas emissions to acquire and surrender emission allowances in return for emitting those greenhouse gases. Moreover, the Environmental Protection Agency (the "**EPA**") has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish construction and operating permit reviews for certain large stationary sources, which may result in the need to meet "best available control technology standards, and also require the monitoring and annual reporting of greenhouse gas emissions from certain petroleum and natural gas system sources in the United States, including onshore and offshore production sources. Certain provinces, including Alberta and British Columbia, have implemented greenhouse gas emission legislation that impacts areas in which the Company operates. It is anticipated that other federal, provincial and state announcements and regulatory frameworks to address emissions will continue to emerge.

Some of our significant facilities may ultimately be subject to future regional, provincial, state and/or federal climate change regulations to manage greenhouse gas emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. 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. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions — Climate Change Regulation*".

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

Our future oil 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. The business of exploring for, developing or acquiring reserves is capital intensive.

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.

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 become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. In addition, we may be unable to find and develop or acquire additional reserves to replace our crude oil and natural gas production at acceptable costs.

**Risks Relating to Ownership of our 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. The covenants in our Credit Facilities and Senior Notes also restrict our ability to pay dividends in certain situations. 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. 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.

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 oil 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.

Any reduction or suspension of the cash dividends that we pay to Shareholders may negatively impact 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 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 qualified reserves evaluators), 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 judgments 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 judgments 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 reserves 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 reserves 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, proved plus probable reserves and proved plus probable plus possible reserves. Probable reserves have a lower certainty of recovery than proved reserves and possible reserves have a lower certainty of recovery than probable 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 and possible reserves. The SEC definitions of proved reserves, probable reserves and possible reserves are different than NI 51-101; therefore, proved, probable, proved plus probable and proved plus probable and possible reserves disclosed in this Annual Information Form may not be comparable to United States standards.

As a consequence of the foregoing, our reserves 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 oil 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***

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by us to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

***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 Alberta and Saskatchewan) and in the United States (primarily in the State of Texas). 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 indentures governing our Senior Notes, 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 us.

### 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 and Baytex Holdings Limited Partnership. Baytex Partnership holds the material operating assets in Canada from which we generate cash flow.

### Baytex Energy USA, Inc.

Baytex USA is a corporation incorporated under the laws of the State of Delaware 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 an indirect wholly-owned subsidiary of us.

### Personnel

As at December 31, 2014, we had 195 employees in our Calgary head office, 33 employees in our Houston office and 94 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**

Our reserves are located in Canada (in Alberta, British Columbia and Saskatchewan) and the United States (in Texas). We retained two independent qualified reserves evaluators, Sproule and Ryder Scott, to evaluate and prepare reports on 100 percent of our proved and probable bitumen, crude oil, NGL and natural gas reserves. Sproule evaluated all of our Canadian properties, representing approximately 56 percent of the assigned total proved plus probable reserves and 58 percent of the total proved plus probable value discounted at 10 percent. Ryder Scott evaluated all of our United States properties, representing approximately 44 percent of the assigned total proved plus probable reserves and 42 percent of the total proved plus probable value discounted at 10 percent. Ryder Scott also audited the possible reserves associated with our Eagle Ford assets.

The statement of reserves data and other oil and natural gas information set forth below is dated March 9, 2015, with an effective date of December 31, 2014. The preparation date of the statement is February 17, 2015 in the case of Sproule, and February 18, 2015 in the case of Ryder Scott. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Sproule and Ryder Scott in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

***Disclosure of Reserves Data***

The proved and probable reserves data of the Corporation set forth below is based upon evaluations by Sproule and Ryder Scott of our proved and probable bitumen, crude oil, NGL and natural gas reserves with an effective date of December 31, 2014, as contained in the consolidated report of Sproule dated February 27, 2015. Sproule prepared the consolidated report by consolidating the Canadian properties evaluated by Sproule with the United States properties evaluated by Ryder Scott, in each case using Sproule's December 31, 2014 forecast price and cost assumptions (and excludes the impact of any hedging activities). The possible reserves data of the Corporation set forth below is based upon the audit by Ryder Scott of the possible reserves associated with our Eagle Ford assets with an effective date of December 31, 2014. The Baytex Reserves Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. See also "*Definitions and Other Notes to Reserves Data Tables*" below.

The tables below are a combined summary of our proved, probable and possible bitumen, crude oil, NGL and natural gas reserves and the net present value of future net revenue attributable to such reserves as evaluated in the Baytex Reserves Report. The tables summarize the data contained in the Baytex Reserves Report and, as a result, may contain slightly different numbers than such report due to rounding. Also due to rounding, certain columns may not add exactly.

**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 Baytex Reserves 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 reserves 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, 2014
## FORECAST PRICES AND COSTS

### CANADA

| RESERVES CATEGORY | HEAVY OIL Gross (Mbbl) | HEAVY OIL Net (Mbbl) | BITUMEN Gross (Mbbl) | BITUMEN Net (Mbbl) | LIGHT AND MEDIUM OIL Gross (Mbbl) | LIGHT AND MEDIUM OIL Net (Mbbl) |
|---|---|---|---|---|---|---|
| PROVED: | | | | | | |
| Developed Producing | 42,428 | 31,736 | 9,763 | 8,128 | 3,423 | 2,955 |
| Developed Non-Producing | 6,350 | 5,365 | — | — | 6 | 6 |
| Undeveloped | 29,367 | 23,576 | 8,295 | 6,764 | 307 | 270 |
| TOTAL PROVED | 78,145 | 60,677 | 18,058 | 14,892 | 3,736 | 3,231 |
| PROBABLE | 39,777 | 30,763 | 73,054 | 56,008 | 2,496 | 2,080 |
| TOTAL PROVED PLUS PROBABLE | 117,922 | 91,440 | 91,112 | 70,900 | 6,232 | 5,311 |

| RESERVES CATEGORY | NATURAL GAS LIQUIDS Gross (Mbbl) | NATURAL GAS LIQUIDS Net (Mbbl) | NATURAL GAS Gross (MMcf) | NATURAL GAS Net (MMcf) | TOTAL RESERVES Gross (Mboe) | TOTAL RESERVES Net (Mboe) |
|---|---|---|---|---|---|---|
| PROVED: | | | | | | |
| Developed Producing | 1,489 | 1,072 | 52,407 | 43,334 | 65,838 | 51,113 |
| Developed Non-Producing | 124 | 85 | 2,686 | 2,186 | 6,928 | 5,820 |
| Undeveloped | 1,075 | 882 | 24,699 | 21,090 | 43,160 | 35,006 |
| TOTAL PROVED | 2,688 | 2,038 | 79,793 | 66,611 | 115,925 | 91,939 |
| PROBABLE | 2,514 | 1,948 | 59,067 | 50,007 | 127,685 | 99,135 |
| TOTAL PROVED PLUS PROBABLE | 5,201 | 3,987 | 138,860 | 116,617 | 243,610 | 191,074 |

### UNITED STATES

| RESERVES CATEGORY | SHALE OIL Gross (Mbbl) | SHALE OIL Net (Mbbl) | NATURAL GAS LIQUIDS Gross (Mbbl) | NATURAL GAS LIQUIDS Net (Mbbl) | SHALE GAS Gross (MMcf) | SHALE GAS Net (MMcf) |
|---|---|---|---|---|---|---|
| PROVED: | | | | | | |
| Developed Producing | 21,256 | 15,668 | 22,167 | 16,358 | 46,252 | 34,144 |
| Developed Non-Producing | — | — | — | — | — | — |
| Undeveloped | 28,077 | 20,690 | 56,728 | 41,769 | 139,352 | 102,666 |
| TOTAL PROVED | 49,333 | 36,358 | 78,895 | 58,126 | 185,604 | 136,810 |
| PROBABLE | 4,546 | 3,352 | 10,240 | 7,551 | 22,543 | 16,618 |
| TOTAL PROVED PLUS PROBABLE | 53,879 | 39,710 | 89,135 | 65,677 | 208,147 | 153,428 |
| POSSIBLE(1) | 31,931 | 23,507 | 131,828 | 96,617 | 299,212 | 219,604 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1) | 85,810 | 63,217 | 220,963 | 162,294 | 507,359 | 373,031 |

| RESERVES CATEGORY | NATURAL GAS Gross (MMcf) | NATURAL GAS Net (MMcf) | TOTAL RESERVES Gross (Mboe) | TOTAL RESERVES Net (Mboe) |
|---|---|---|---|---|
| PROVED: | | | | |
| Developed Producing | 22,261 | 16,400 | 54,842 | 40,450 |
| Developed Non-Producing | — | — | — | — |
| Undeveloped | 26,708 | 19,690 | 112,481 | 82,851 |
| TOTAL PROVED | 48,969 | 36,090 | 167,323 | 123,301 |
| PROBABLE | 12,824 | 9,467 | 20,680 | 15,250 |
| TOTAL PROVED PLUS PROBABLE | 61,793 | 45,557 | 188,003 | 138,551 |
| POSSIBLE[1] | 40,964 | 30,182 | 220,455 | 161,755 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[1] | 102,757 | 75,739 | 408,458 | 300,306 |

**TOTAL**

| RESERVES CATEGORY | HEAVY OIL Gross (Mbbl) | HEAVY OIL Net (Mbbl) | BITUMEN Gross (Mbbl) | BITUMEN Net (Mbbl) | LIGHT AND MEDIUM OIL Gross (Mbbl) | LIGHT AND MEDIUM OIL Net (Mbbl) |
|---|---|---|---|---|---|---|
| PROVED: | | | | | | |
| Developed Producing | 42,428 | 31,736 | 9,763 | 8,128 | 3,423 | 2,955 |
| Developed Non-Producing | 6,350 | 5,365 | — | — | 6 | 6 |
| Undeveloped | 29,367 | 23,576 | 8,295 | 6,764 | 307 | 270 |
| TOTAL PROVED | 78,145 | 60,677 | 18,058 | 14,892 | 3,736 | 3,231 |
| PROBABLE | 39,777 | 30,763 | 73,054 | 56,008 | 2,496 | 2,080 |
| TOTAL PROVED PLUS PROBABLE | 117,922 | 91,440 | 91,112 | 70,900 | 6,232 | 5,311 |
| POSSIBLE[1][2] | — | — | — | — | — | — |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[1][2] | 117,922 | 91,440 | 91,112 | 70,900 | 6,232 | 5,311 |

| RESERVES CATEGORY | SHALE OIL Gross (Mbbl) | SHALE OIL Net (Mbbl) | NATURAL GAS LIQUIDS Gross (Mbbl) | NATURAL GAS LIQUIDS Net (Mbbl) | SHALE GAS Gross (MMcf) | SHALE GAS Net (MMcf) |
|---|---|---|---|---|---|---|
| PROVED: | | | | | | |
| Developed Producing | 21,256 | 15,668 | 23,656 | 17,429 | 46,252 | 34,144 |
| Developed Non-Producing | — | — | 124 | 85 | — | — |
| Undeveloped | 28,077 | 20,690 | 57,802 | 42,650 | 139,352 | 102,666 |
| TOTAL PROVED | 49,333 | 36,358 | 81,583 | 60,165 | 185,604 | 136,810 |
| PROBABLE | 4,546 | 3,352 | 12,753 | 9,499 | 22,543 | 16,618 |
| TOTAL PROVED PLUS PROBABLE | 53,879 | 39,710 | 94,336 | 69,664 | 208,147 | 153,428 |
| POSSIBLE[1][2] | 31,931 | 23,507 | 131,828 | 96,617 | 299,212 | 219,604 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE[1][2] | 85,810 | 63,217 | 226,164 | 166,281 | 507,359 | 373,031 |

| RESERVES CATEGORY | NATURAL GAS Gross (MMcf) | NATURAL GAS Net (MMcf) | TOTAL RESERVES Gross (Mboe) | TOTAL RESERVES Net (Mboe) |
|---|---|---|---|---|
| PROVED: | | | | |
| Developed Producing | 74,668 | 59,734 | 120,680 | 91,563 |
| Developed Non-Producing | 2,686 | 2,186 | 6,928 | 5,820 |
| Undeveloped | 51,407 | 40,780 | 155,641 | 117,857 |
| TOTAL PROVED | 128,762 | 102,701 | 283,249 | 215,240 |
| PROBABLE | 71,891 | 59,474 | 148,365 | 114,385 |
| TOTAL PROVED PLUS PROBABLE | 200,653 | 162,174 | 431,614 | 329,624 |
| POSSIBLE(1)(2) | 40,964 | 30,182 | 220,455 | 161,755 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1)(2) | 241,617 | 192,356 | 652,069 | 491,379 |

Notes:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE**
**AS OF DECEMBER 31, 2014**
**FORECAST PRICES AND COSTS**

## CANADA

| RESERVES CATEGORY | BEFORE INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s) | 5% ($000s) | 10% ($000s) | 15% ($000s) | 20% ($000s) |
|---|---|---|---|---|---|
| PROVED: | | | | | |
| Developed Producing | 1,767,983 | 1,467,827 | 1,259,500 | 1,107,199 | 991,311 |
| Developed Non-Producing | 238,357 | 169,627 | 127,382 | 99,693 | 80,550 |
| Undeveloped | 1,122,000 | 812,642 | 605,669 | 461,548 | 357,787 |
| TOTAL PROVED | 3,128,340 | 2,450,097 | 1,992,552 | 1,668,440 | 1,429,648 |
| PROBABLE | 3,877,356 | 2,104,276 | 1,282,788 | 845,561 | 586,769 |
| TOTAL PROVED PLUS PROBABLE | 7,005,696 | 4,554,373 | 3,275,340 | 2,514,000 | 2,016,417 |

## UNITED STATES

| RESERVES CATEGORY | 0% ($000s) | 5% ($000s) | 10% ($000s) | 15% ($000s) | 20% ($000s) |
|---|---|---|---|---|---|
| PROVED: | | | | | |
| Developed Producing | 1,707,246 | 1,330,374 | 1,093,873 | 934,314 | 820,303 |
| Developed Non-Producing | — | — | — | — | — |
| Undeveloped | 2,395,266 | 1,505,012 | 982,948 | 654,064 | 435,208 |
| TOTAL PROVED | 4,102,511 | 2,835,386 | 2,076,821 | 1,588,379 | 1,255,510 |
| PROBABLE | 708,159 | 438,018 | 306,608 | 232,914 | 186,785 |
| TOTAL PROVED PLUS PROBABLE | 4,810,670 | 3,273,404 | 2,383,429 | 1,821,293 | 1,442,295 |
| POSSIBLE(1) | 5,396,827 | 2,388,440 | 1,154,269 | 593,860 | 318,479 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1) | 10,207,497 | 5,661,844 | 3,537,698 | 2,415,153 | 1,760,774 |

## TOTAL

| RESERVES CATEGORY | 0% ($000s) | 5% ($000s) | 10% ($000s) | 15% ($000s) | 20% ($000s) |
|---|---|---|---|---|---|
| PROVED: | | | | | |
| Developed Producing | 3,475,229 | 2,798,201 | 2,353,373 | 2,041,513 | 1,811,614 |
| Developed Non-Producing | 238,357 | 169,627 | 127,382 | 99,693 | 80,550 |
| Undeveloped | 3,517,266 | 2,317,654 | 1,588,617 | 1,115,612 | 792,995 |
| TOTAL PROVED | 7,230,851 | 5,285,483 | 4,069,373 | 3,256,819 | 2,685,158 |
| PROBABLE | 4,585,514 | 2,542,295 | 1,589,396 | 1,078,476 | 773,554 |
| TOTAL PROVED PLUS PROBABLE | 11,816,366 | 7,827,777 | 5,658,769 | 4,335,293 | 3,458,712 |
| POSSIBLE(1)(2) | 5,396,827 | 2,388,440 | 1,154,269 | 593,860 | 318,479 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1)(2) | 17,213,193 | 10,216,217 | 6,813,038 | 4,929,153 | 3,777,191 |

**SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE**
**AS OF DECEMBER 31, 2014**
**FORECAST PRICES AND COSTS**

**CANADA**

| | AFTER INCOME TAXES DISCOUNTED AT (%/year) | | | | |
|---|---|---|---|---|---|
| **RESERVES CATEGORY** | **0% ($000s)** | **5% ($000s)** | **10% ($000s)** | **15% ($000s)** | **20% ($000s)** |
| PROVED: | | | | | |
| Developed Producing | 1,648,886 | 1,375,073 | 1,184,689 | 1,045,130 | 938,624 |
| Developed Non-Producing | 178,588 | 125,685 | 93,541 | 72,654 | 58,307 |
| Undeveloped | 832,990 | 587,702 | 424,680 | 312,023 | 231,606 |
| TOTAL PROVED | 2,660,465 | 2,088,461 | 1,702,910 | 1,429,808 | 1,228,537 |
| PROBABLE | 2,925,074 | 1,556,724 | 925,387 | 590,713 | 393,581 |
| TOTAL PROVED PLUS PROBABLE | 5,585,539 | 3,645,184 | 2,628,297 | 2,020,520 | 1,622,117 |

**UNITED STATES**

| **RESERVES CATEGORY** | | | | | |
|---|---|---|---|---|---|
| PROVED: | | | | | |
| Developed Producing | 1,697,262 | 1,322,973 | 1,088,136 | 929,696 | 816,467 |
| Developed Non-Producing | — | — | — | — | — |
| Undeveloped | 1,890,798 | 1,196,586 | 786,614 | 524,943 | 348,052 |
| TOTAL PROVED | 3,588,061 | 2,519,559 | 1,874,750 | 1,454,638 | 1,164,519 |
| PROBABLE | 532,400 | 322,936 | 225,781 | 173,670 | 142,219 |
| TOTAL PROVED PLUS PROBABLE | 4,120,461 | 2,842,494 | 2,100,531 | 1,628,308 | 1,306,738 |
| POSSIBLE(1) | 3,805,712 | 1,657,905 | 797,420 | 411,645 | 222,608 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1) | 7,926,173 | 4,500,399 | 2,897,951 | 2,039,953 | 1,529,345 |

**TOTAL**

| **RESERVES CATEGORY** | | | | | |
|---|---|---|---|---|---|
| PROVED: | | | | | |
| Developed Producing | 3,346,148 | 2,698,046 | 2,272,825 | 1,974,826 | 1,755,091 |
| Developed Non-Producing | 178,588 | 125,685 | 93,541 | 72,654 | 58,307 |
| Undeveloped | 2,723,788 | 1,784,288 | 1,211,294 | 836,966 | 579,658 |
| TOTAL PROVED | 6,248,526 | 4,608,020 | 3,577,660 | 2,884,446 | 2,393,056 |
| PROBABLE | 3,457,474 | 1,879,660 | 1,151,168 | 764,383 | 535,800 |
| TOTAL PROVED PLUS PROBABLE | 9,706,000 | 6,487,678 | 4,728,828 | 3,648,828 | 2,928,855 |
| POSSIBLE(1)(2) | 3,805,712 | 1,657,905 | 797,420 | 411,645 | 222,608 |
| TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE(1)(2) | 13,511,712 | 8,145,583 | 5,526,248 | 4,060,473 | 3,151,463 |

Notes:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

**TOTAL FUTURE NET REVENUE (UNDISCOUNTED)**
**AS OF DECEMBER 31, 2014**
**FORECAST PRICES AND COSTS**

| | REVENUE ($000s) | ROYALTIES ($000s) | OPERATING COSTS ($000s) | DEVELOPMENT COSTS ($000s) | WELL ABANDONMENT COSTS ($000s) | FUTURE NET REVENUE BEFORE INCOME TAXES ($000s) | INCOME TAXES ($000s) | FUTU NET REVEN AFTE INCO TAX ($000 |
|---|---|---|---|---|---|---|---|---|
| **TOTAL PROVED RESERVES** | | | | | | | | |
| Canada | 7,492,624 | 1,492,594 | 2,187,390 | 658,462 | 25,838 | 3,128,340 | 467,875 | 2,6 |
| United States | 11,991,247 | 3,726,396 | 2,406,999 | 1,720,107 | 35,233 | 4,102,511 | 514,450 | 3,5 |
| **Total** | 19,483,871 | 5,218,990 | 4,594,389 | 2,378,569 | 61,071 | 7,230,851 | 982,326 | 6,2 |
| **TOTAL PROVED PLUS PROBABLE RESERVES** | | | | | | | | |
| Canada | 17,643,023 | 3,778,302 | 5,157,211 | 1,655,155 | 46,657 | 7,005,696 | 1,420,157 | 5,5 |
| United States | 13,502,415 | 4,199,655 | 2,735,359 | 1,720,107 | 36,625 | 4,810,670 | 690,208 | 4,1 |
| **Total** | 31,145,438 | 7,977,957 | 7,892,570 | 3,375,262 | 83,282 | 11,816,366 | 2,110,365 | 9,7 |
| **TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE RESERVES**(1)(2) | | | | | | | | |
| Canada | 17,643,023 | 3,778,302 | 5,157,211 | 1,655,155 | 46,657 | 7,005,696 | 1,420,157 | 5,5 |
| United States | 31,424,539 | 9,818,088 | 6,213,074 | 5,103,870 | 82,010 | 10,207,497 | 2,281,323 | 7,9 |
| **Total** | 49,067,562 | 13,596,390 | 11,370,285 | 6,759,025 | 128,667 | 17,213,193 | 3,701,480 | 13,5 |

Notes:

(1) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(2) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

**FUTURE NET REVENUE BY PRODUCTION GROUP**
**AS OF DECEMBER 31, 2014**
**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 | Heavy Oil (including solution gas and other by-products) | 1,439,959 | 23.30 |
| | Bitumen (including solution gas and other by-products) | 330,601 | 22.20 |
| | Light and Medium Crude Oil (including solution gas and other by-products) | 92,681 | 25.14 |
| | Natural Gas (including by-products but excluding natural gas from oil wells) | 129,310 | 11.19 |
| | **Total Canada** | 1,992,552 | |
| Proved plus Probable | Heavy Oil (including solution gas and other by-products) | 2,151,152 | 23.07 |
| | Bitumen (including solution gas and other by-products) | 797,380 | 11.25 |
| | Light and Medium Crude Oil (including solution gas and other by-products) | 132,250 | 20.15 |
| | Natural Gas (including by-products but excluding natural gas from oil wells) | 194,557 | 9.55 |
| | **Total Canada** | 3,275,340 | |
| Proved | Shale Oil (including solution gas and other by-products) | 904,792 | 18.71 |
| | Shale Gas (including by-products but excluding natural gas from shale oil wells) | 1,172,029 | 15.64 |
| | **Total United States** | 2,076,821 | |
| Proved plus Probable | Shale Oil (including solution gas and other by-products) | 1,042,417 | 19.02 |
| | Shale Gas (including by-products but excluding natural gas from shale oil wells) | 1,341,012 | 16.01 |
| | **Total United States** | 2,383,429 | |
| Proved plus Probable plus Possible(2) | Shale Oil (including solution gas and other by-products) | 1,195,683 | 13.53 |
| | Shale Gas (including by-products but excluding natural gas from shale oil wells) | 2,342,015 | 11.05 |
| | **Total United States** | 3,537,698 | |
| **TOTAL** | | | |
| Proved | Heavy Oil (including solution gas and other by-products) | 1,439,959 | 23.30 |
| | Bitumen (including solution gas and other by-products) | 330,601 | 22.20 |
| | Light and Medium Crude Oil (including solution gas and other by-products) | 92,681 | 25.14 |
| | Shale Oil (including solution gas and other by-products) | 904,792 | 18.71 |
| | Shale Gas (including by-products but excluding natural gas from shale oil wells) | 1,172,029 | 15.64 |
| | Natural Gas (including by-products but excluding natural gas from oil wells) | 129,310 | 11.19 |
| | **Total** | 4,069,373 | |
| Proved plus | Heavy Oil (including solution gas and other by-products) | 2,151,152 | 23.07 |

| | | | |
|---|---|---|---|
| Probable | Bitumen (including solution gas and other by-products) | 797,380 | 11.25 |
| | Light and Medium Crude Oil (including solution gas and other by-products) | 132,250 | 20.15 |
| | Shale Oil (including solution gas and other by-products) | 1,042,417 | 19.02 |
| | Shale Gas (including by-products but excluding natural gas from shale oil wells) | 1,341,012 | 16.01 |
| | Natural Gas (including by-products but excluding natural gas from oil wells) | 194,557 | 9.55 |
| | **Total** | 5,658,769 | |

| RESERVES CATEGORY | PRODUCTION GROUP | FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s) | UNIT VALUE ($/boe)[1] |
|---|---|---|---|
| Proved plus | Heavy Oil (including solution gas and other by-products) | 2,151,152 | 23.07 |
| Probable plus | Bitumen (including solution gas and other by-products) | 797,380 | 11.25 |
| Possible[2][3] | Light and Medium Crude Oil (including solution gas and other by-products) | 132,250 | 20.15 |
| | Shale Oil (including solution gas and other by-products) | 1,195,683 | 13.53 |
| | Shale Gas (including by-products but excluding natural gas from shale oil wells) | 2,342,015 | 11.05 |
| | Natural Gas (including by-products but excluding natural gas from oil wells) | 194,557 | 9.55 |
| | **Total** | 6,813,038 | |

Notes:

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

(2) Possible reserves are those reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

(3) The total possible reserves include only possible reserves from the Eagle Ford assets. The possible reserves associated with the Canadian properties have not been evaluated.

***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 reserves categories are as follows:

   *Reserves 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) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

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

*Development and Production Status*

Each of the reserves categories (proved, probable and possible) 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 the following categories:

(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 reserves 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; and

(c) at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible 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 in the tables may not add due to rounding.

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

***Pricing Assumptions***

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, and natural gas benchmark reference pricing, as at December 31, 2014, inflation and exchange rates utilized in the Baytex Reserves Report were as follows:

**SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS**
**FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2014[(1)]**

| | OIL | | | NATURAL GAS | | | |
|---|---|---|---|---|---|---|---|
| | WTI Cushing Oklahoma[(2)] ($US/bbl) | Canada Light Sweet[(3)] ($Cdn/bbl) | Western Canadian Select 20.5° API[(4)] ($Cdn/bbl) | AECO-C[(5)] ($Cdn/MMbtu) | Henry Hub[(6)] ($US/Mmbtu) | Inflation Rate[(7)] %/year | Exchange Rate[(8)] ($US/$Cdn) |
| Historical | | | | | | | |
| 2010 | 79.43 | 77.80 | 67.21 | 4.16 | 4.39 | 1.2 | 0.971 |
| 2011 | 95.00 | 95.16 | 77.09 | 3.72 | 4.04 | 1.6 | 1.012 |
| 2012 | 94.19 | 86.57 | 73.08 | 2.43 | 2.79 | 1.3 | 1.001 |
| 2013 | 97.98 | 93.24 | 73.78 | 3.13 | 3.68 | 0.8 | 0.971 |
| 2014 | 93.00 | 94.18 | 82.04 | 4.50 | 4.28 | 1.4 | 0.905 |
| Forecast | | | | | | | |
| 2015 | 65.00 | 70.35 | 60.50 | 3.32 | 3.25 | 1.5 | 0.850 |
| 2016 | 80.00 | 87.36 | 75.13 | 3.71 | 3.75 | 1.5 | 0.870 |
| 2017 | 90.00 | 98.28 | 84.52 | 3.90 | 4.00 | 1.5 | 0.870 |
| 2018 | 91.35 | 99.75 | 85.79 | 4.47 | 4.50 | 1.5 | 0.870 |
| 2019 | 92.72 | 101.25 | 87.07 | 5.05 | 5.00 | 1.5 | 0.870 |
| Thereafter | | | | Escalation Rate of 1.5% | | | |

Notes:

(1) Each price from the Sproule forecast was adjusted for quality differentials and transportation costs applicable to the specific product and evaluation area.

(2) Price used in the preparation of shale oil reserves in the United States.

(3) Price used in the preparation of light and medium crude oil and natural gas liquids reserves in Canada.

(4) Price used in the preparation of heavy oil and bitumen reserves in Canada.

(5) Price used in the preparation of natural gas reserves in Canada.

(6) Price used in the preparation of shale gas reserves in the United States.

(7) Inflation rates for forecasting prices and costs.

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

Weighted average prices realized by us for the year ended December 31, 2014, excluding hedging activities, were $69.26/bbl for heavy oil, $74.24/bbl for bitumen, $107.64/bbl for light oil, $90.75/bbl for shale oil, $35.28/bbl for NGL, $4.56/Mcf for shale gas and $4.52/Mcf for natural gas.

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

| | HEAVY OIL | | | BITUMEN | | |
|---|---|---|---|---|---|---|
| CANADA | Proved (Mbbl) | Probable (Mbbl) | Proved Plus Probable (Mbbl) | Proved (Mbbl) | Probable (Mbbl) | Proved Plus Probable (Mbbl) |
| **December 31, 2013** | 82,903 | 42,643 | 125,547 | 19,322 | 82,564 | 101,886 |
| Extensions | 5,447 | 3,946 | 9,393 | — | — | — |
| Infill Drilling | 2,661 | 1,081 | 3,742 | — | — | — |
| Improved Recovery | 41 | 8 | 49 | — | 26,393 | 26,393 |
| Technical Revisions | 1,226 | (7,120) | (5,893) | 2 | (35,919) | (35,917) |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 4,064 | 1,325 | 5,389 | — | — | — |
| Dispositions | (3,011) | (2,090) | (5,101) | — | — | — |
| Economic Factors | (11) | (18) | (28) | (8) | 16 | 8 |
| Production | (15,175) | — | (15,175) | (1,258) | — | (1,258) |
| **December 31, 2014** | 78,145 | 39,777 | 117,922 | 18,058 | 73,054 | 91,112 |

| | LIGHT AND MEDIUM OIL | | | NATURAL GAS | | |
|---|---|---|---|---|---|---|
| CANADA | Proved (Mbbl) | Probable (Mbbl) | Proved Plus Probable (Mbbl) | Proved (MMcf) | Probable (MMcf) | Proved Plus Probable (MMcf) |
| **December 31, 2013** | 5,707 | 3,424 | 9,131 | 68,316 | 60,523 | 128,839 |
| Extensions | — | — | — | 1,666 | 16,148 | 17,813 |
| Infill Drilling | 102 | 21 | 123 | 1,395 | 436 | 1,831 |
| Improved Recovery | — | — | — | 2 | — | 2 |
| Technical Revisions | (583) | (277) | (860) | 37,730 | (11,939) | 25,792 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | — | — | — | — | — | — |
| Dispositions | (493) | (677) | (1,170) | (8,084) | (8,824) | (16,908) |
| Economic Factors | (39) | 4 | (35) | (5,523) | 2,723 | (2,800) |
| Production | (957) | — | (957) | (15,709) | — | (15,709) |
| **December 31, 2014** | 3,736 | 2,496 | 6,232 | 79,793 | 59,067 | 138,860 |

| | NATURAL GAS LIQUIDS | | | OIL EQUIVALENT | | |
|---|---|---|---|---|---|---|
| CANADA | Proved (Mbbl) | Probable (Mbbl) | Proved Plus Probable (Mbbl) | Proved (Mboe) | Probable (Mboe) | Proved Plus Probable (Mboe) |
| **December 31, 2013** | 3,073 | 3,469 | 6,542 | 122,390 | 142,188 | 264,578 |
| Extensions | 81 | 808 | 889 | 5,806 | 7,445 | 13,251 |
| Infill Drilling | 48 | 12 | 60 | 3,043 | 1,187 | 4,230 |
| Improved Recovery | — | — | — | 42 | 26,401 | 26,443 |
| Technical Revisions | 784 | (821) | (37) | 7,718 | (46,126) | (38,408) |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | — | — | — | 4,064 | 1,325 | 5,389 |
| Dispositions | (749) | (950) | (1,699) | (5,600) | (5,187) | (10,787) |
| Economic Factors | (24) | (5) | (28) | (1,003) | 452 | (551) |
| Production | (526) | — | (526) | (20,534) | — | (20,534) |
| **December 31, 2014** | 2,688 | 2,514 | 5,201 | 115,925 | 127,685 | 243,610 |

| UNITED STATES | LIGHT AND MEDIUM OIL Proved (Mbbl) | LIGHT AND MEDIUM OIL Probable (Mbbl) | LIGHT AND MEDIUM OIL Proved Plus Probable (Mbbl) | NATURAL GAS Proved (MMcf) | NATURAL GAS Probable (MMcf) | NATURAL GAS Proved Plus Probable (MMcf) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | 30,242 | 13,341 | 43,583 | 41,349 | 18,373 | 59,722 |
| Extensions | — | — | — | — | — | — |
| Infill Drilling | — | — | — | — | — | — |
| Improved Recovery | — | — | — | — | — | — |
| Technical Revisions | — | — | — | — | — | — |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | — | — | — | 49,312 | 12,824 | 62,136 |
| Dispositions | (29,419) | (13,341) | (42,760) | (41,098) | (18,373) | (59,471) |
| Economic Factors | — | — | — | — | — | — |
| Production | (823) | — | (823) | (594) | — | (594) |
| **December 31, 2014** | — | — | — | 48,969 | 12,824 | 61,793 |

| UNITED STATES | SHALE OIL Proved (Mbbl) | SHALE OIL Probable (Mbbl) | SHALE OIL Proved Plus Probable (Mbbl) | NATURAL GAS LIQUIDS Proved (Mbbl) | NATURAL GAS LIQUIDS Probable (Mbbl) | NATURAL GAS LIQUIDS Proved Plus Probable (Mbbl) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | — | — | — | — | — | — |
| Extensions | — | — | — | — | — | — |
| Infill Drilling | 14,044 | (8,822) | 5,222 | 37,410 | (20,453) | 16,957 |
| Improved Recovery | — | — | — | — | — | — |
| Technical Revisions | — | — | — | 42 | — | 42 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 38,506 | 13,367 | 51,873 | 44,133 | 30,693 | 74,826 |
| Dispositions | — | — | — | — | — | — |
| Economic Factors | — | — | — | — | — | — |
| Production | (3,217) | — | (3,217) | (2,690) | — | (2,690) |
| **December 31, 2014** | 49,333 | 4,546 | 53,879 | 78,895 | 10,240 | 89,135 |

| UNITED STATES | SHALE GAS Proved (MMcf) | SHALE GAS Probable (MMcf) | SHALE GAS Proved Plus Probable (MMcf) | OIL EQUIVALENT Proved (Mboe) | OIL EQUIVALENT Probable (Mboe) | OIL EQUIVALENT Proved Plus Probable (Mboe) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | — | — | — | 37,134 | 16,403 | 53,537 |
| Extensions | — | — | — | — | — | — |
| Infill Drilling | 99,144 | (60,022) | 39,122 | 67,978 | (39,279) | 28,699 |
| Improved Recovery | — | — | — | — | — | — |
| Technical Revisions | — | — | — | 42 | — | 42 |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 93,969 | 82,564 | 176,533 | 106,519 | 59,959 | 166,478 |
| Dispositions | — | — | — | (36,269) | (16,403) | (52,672) |
| Economic Factors | — | — | — | — | — | — |
| Production | (7,508) | — | (7,508) | (8,080) | — | (8,080) |
| **December 31, 2014** | 185,604 | 22,543 | 208,147 | 167,323 | 20,680 | 188,003 |

| TOTAL | HEAVY OIL Proved (Mbbl) | HEAVY OIL Probable (Mbbl) | HEAVY OIL Proved Plus Probable (Mbbl) | BITUMEN Proved (Mbbl) | BITUMEN Probable (Mbbl) | BITUMEN Proved Plus Probable (Mbbl) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | 82,903 | 42,643 | 125,547 | 19,322 | 82,564 | 101,886 |
| Extensions | 5,447 | 3,946 | 9,393 | — | — | — |
| Infill Drilling | 2,661 | 1,081 | 3,742 | — | — | — |
| Improved Recovery | 41 | 8 | 49 | — | 26,393 | 26,393 |
| Technical Revisions | 1,226 | (7,120) | (5,893) | 2 | (35,919) | (35,917) |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 4,064 | 1,325 | 5,389 | — | — | — |
| Dispositions | (3,011) | (2,090) | (5,101) | — | — | — |
| Economic Factors | (11) | (18) | (28) | (8) | 16 | 8 |
| Production | (15,175) | — | (15,175) | (1,258) | — | (1,258) |
| **December 31, 2014** | 78,145 | 39,777 | 117,922 | 18,058 | 73,054 | 91,112 |

| TOTAL | LIGHT AND MEDIUM OIL Proved (Mbbl) | LIGHT AND MEDIUM OIL Probable (Mbbl) | LIGHT AND MEDIUM OIL Proved Plus Probable (Mbbl) | SHALE OIL Proved (Mbbl) | SHALE OIL Probable (Mbbl) | SHALE OIL Proved Plus Probable (Mbbl) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | 35,949 | 16,765 | 52,714 | — | — | — |
| Extensions | — | — | — | — | — | — |
| Infill Drilling | 102 | 21 | 123 | 14,044 | (8,822) | 5,222 |
| Improved Recovery | — | — | — | — | — | — |
| Technical Revisions | (583) | (277) | (860) | — | — | — |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | — | — | — | 38,506 | 13,367 | 51,873 |
| Dispositions | (29,912) | (14,018) | (43,930) | — | — | — |
| Economic Factors | (39) | 4 | (35) | — | — | — |
| Production | (1,780) | — | (1,780) | (3,217) | — | (3,217) |
| **December 31, 2014** | 3,736 | 2,496 | 6,232 | 49,333 | 4,546 | 53,879 |

| TOTAL | NATURAL GAS LIQUIDS Proved (Mbbl) | NATURAL GAS LIQUIDS Probable (Mbbl) | NATURAL GAS LIQUIDS Proved Plus Probable (Mbbl) | SHALE GAS Proved (MMcf) | SHALE GAS Probable (MMcf) | SHALE GAS Proved Plus Probable (MMcf) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | 3,073 | 3,469 | 6,542 | — | — | — |
| Extensions | 81 | 808 | 889 | — | — | — |
| Infill Drilling | 37,458 | (20,441) | 17,017 | 99,144 | (60,022) | 39,122 |
| Improved Recovery | — | — | — | — | — | — |
| Technical Revisions | 826 | (821) | 5 | — | — | — |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 44,133 | 30,693 | 74,826 | 93,969 | 82,564 | 176,533 |
| Dispositions | (749) | (950) | (1,699) | — | — | — |
| Economic Factors | (24) | (5) | (28) | — | — | — |
| Production | (3,216) | — | (3,216) | (7,508) | — | (7,508) |
| **December 31, 2014** | 81,583 | 12,753 | 94,336 | 185,604 | 22,543 | 208,147 |

| TOTAL | NATURAL GAS Proved (MMcf) | Probable (MMcf) | Proved Plus Probable (MMcf) | OIL EQUIVALENT Proved (Mboe) | Probable (Mboe) | Proved Plus Probable (Mboe) |
|---|---|---|---|---|---|---|
| **December 31, 2013** | 109,665 | 78,896 | 188,561 | 159,524 | 158,592 | 318,115 |
| Extensions | 1,666 | 16,148 | 17,813 | 5,806 | 7,445 | 13,251 |
| Infill Drilling | 1,395 | 436 | 1,831 | 71,021 | (38,092) | 32,929 |
| Improved Recovery | 2 | — | 2 | 42 | 26,401 | 26,443 |
| Technical Revisions | 37,730 | (11,939) | 25,791 | 7,759 | (46,126) | (38,366) |
| Discoveries | — | — | — | — | — | — |
| Acquisitions | 49,312 | 12,824 | 62,136 | 110,583 | 61,284 | 171,866 |
| Dispositions | (49,182) | (27,197) | (76,379) | (41,869) | (21,591) | (63,459) |
| Economic Factors | (5,523) | 2,723 | (2,800) | (1,003) | 452 | (551) |
| Production | (16,302) | — | (16,302) | (28,614) | — | (28,614) |
| **December 31, 2014** | 128,762 | 71,891 | 200,653 | 283,249 | 148,365 | 431,614 |

***Additional Information Relating to Reserves Data***

*Undeveloped Reserves*

Undeveloped reserves are attributed by Sproule and Ryder Scott 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.

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*".

Proved Undeveloped Reserves

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

| | Heavy Oil Gross (Mbbl) | | Bitumen Gross (Mbbl) | | Light and Medium Oil Gross (Mbbl) | | Shale Oil Gross (Mbbl) | |
|---|---|---|---|---|---|---|---|---|
| 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 | 77,247 | 276,943 | 16,667 | 35,494 | 20,035 | 52,503 | — | — |
| 2012 | 4,382 | 32,577 | 1,897 | 14,044 | 6,647 | 15,736 | — | — |
| 2013 | 4,203 | 32,433 | 490 | 8,409 | 15,083 | 25,792 | — | — |
| 2014 | 4,490 | 29,367 | — | 8,295 | — | 307 | 28,077 | 28,077 |

| | Natural Gas Liquids Gross (Mbbl) | | Shale Gas Gross (MMcf) | | Natural Gas Gross (MMcf) | |
|---|---|---|---|---|---|---|
| Year | First Attributed | Booked at Year End | First Attributed | Booked at Year End | First Attributed | Booked at Year End |
| Prior | 4,782 | 6,938 | — | — | 51,400 | 126,485 |
| 2012 | 1,612 | 3,316 | — | — | 12,234 | 25,639 |
| 2013 | 236 | 965 | — | — | 25,329 | 51,757 |
| 2014 | 56,850 | 57,802 | 139,352 | 139,352 | 26,412 | 51,407 |

Sproule assigned proved undeveloped reserves to a total of 363 well locations in Canada, in which Baytex owns a working interest. Ryder Scott assigned proved undeveloped reserves to a total of 196 well locations in the United States, in which Baytex owns a working interest. Each of these 559 locations with a proved undeveloped reserves attribution also has a probable undeveloped assignment.

Of these 363 locations in Canada with proved undeveloped reserves, which were evaluated by Sproule, there are 43 locations in our Peace River primary heavy oil properties. These locations, which will be drilled over the next 4 years, will produce heavy oil by primary recovery. Located in our heavy oil properties in Saskatchewan and northeast Alberta are 296 locations. We expect to drill these locations over the next 10 years, with nearly 99% being drilled within 5 years. There are 16 locations in our light oil properties, which are scheduled to be developed over the next 6 years. Located in our Peace River in-situ thermal recovery project are 8 locations which will be drilled over the next 4 years.

The 196 locations with proved undeveloped reserves, which were evaluated by Ryder Scott, are located in the Eagle Ford property in the Sugarkane Field of Texas. These locations will be developed as horizontal wells using multi-stage hydraulic fracturing technology. There are 188 locations with reserves attributed to the Lower Eagle Ford horizon, and 8 locations with reserves attributed to the Austin Chalk horizon. All of the locations in the Eagle Ford Property are scheduled to be drilled over the next 5 years.

It would not be prudent from both a financial and technical perspective for us to develop all of our proved undeveloped reserves over the next two years. Planned activity levels vary each year due to factors such as capital availability, prevailing commodity prices, operational spacing considerations and regulatory processes. 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 and Ryder Scott defined proved undeveloped inventory.

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.

| | Heavy Oil Gross (Mbbl) | | Bitumen Gross (Mbbl) | | Light and Medium Oil Gross (Mbbl) | | Shale Oil Gross (Mbbl) | |
|---|---|---|---|---|---|---|---|---|
| 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 | 52,616 | 150,459 | 28,203 | 65,313 | 25,102 | 43,483 | — | — |
| 2012 | 9,402 | 24,453 | 52,919 | 77,818 | 6,181 | 10,414 | — | — |
| 2013 | 4,292 | 24,695 | 210 | 73,404 | 6,956 | 13,406 | — | — |
| 2014 | 3,884 | 21,824 | 26,904 | 63,989 | — | 1,532 | 2,415 | 2,415 |

| | Natural Gas Liquids Gross (Mbbl) | | Shale Gas Gross (MMcf) | | Natural Gas Gross (MMcf) | |
|---|---|---|---|---|---|---|
| Year | First Attributed | Booked at Year End | First Attributed | Booked at Year End | First Attributed | Booked at Year End |
| Prior | 3,408 | 4,760 | — | — | 46,439 | 96,164 |
| 2012 | 1,112 | 2,468 | — | — | 7,912 | 19,055 |
| 2013 | 1,766 | 2,836 | — | — | 43,070 | 61,470 |
| 2014 | 8,347 | 9,572 | 16,714 | 16,714 | 26,941 | 54,060 |

In addition to those locations with proved undeveloped reserves, Sproule assigned reserves to a total of 254 well locations with probable undeveloped reserves only. None of these 254 locations have any proved undeveloped reserves assigned to them.

Of these 254 locations with probable undeveloped reserves only, there are 57 locations in our Peace River primary heavy oil properties. These locations, which will be drilled over the next 5 years, will produce heavy oil by primary recovery. There are 108 locations in our heavy oil properties in Saskatchewan and northeast Alberta. We expect to drill these locations over the next 10 years. Located in our light oil properties are 34 locations which will be developed over the next 6 years. Located in our Peace River in-situ thermal recovery project are 27 locations. These locations will be drilled over the next 5 years. There are 28 well pairs located in our Gemini SAGD project. These well pairs will be drilled over the next 27 years. The SAGD recovery process at Gemini requires that we drill pairs of wells, one above the other, separated by approximately 5 metres. Because the process requires a pair of wells for the production of bitumen, we count a well pair as a single well. The additional 28 well pairs would completely develop our Gemini SAGD project. Because steam generation is such a large proportion of the capital and operating costs at Gemini, drilling and steaming of wells is scheduled over the next 27 years to make the most efficient use of our steam generating and oil treating facilities.

The table entitled "Probable Undeveloped Reserves" shows the probable undeveloped reserves for all of our locations, including the 559 locations with both a proved and probable undeveloped assignment, and those 254 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. Planned activity levels vary each year due to factors such as capital availability, prevailing commodity prices, operational spacing considerations and regulatory processes. 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 and Ryder Scott 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 Peace River, Ardmore and

Cold Lake bitumen and heavy oil properties located in the Province of Alberta, and at our conventional light oil and gas properties in Pembina, Alberta. Our Eagle Ford property in Texas, USA also contains 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 forecast prices and costs used in the Baytex Reserves Report, 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).

**FUTURE DEVELOPMENT COSTS**
**AS OF DECEMBER 31, 2014**
**FORECAST PRICES AND COSTS**
**($000s)**

| | CANADA | | UNITED STATES | | TOTAL | |
|---|---|---|---|---|---|---|
| | Proved Reserves | Proved plus Probable Reserves | Proved Reserves | Proved plus Probable Reserves | Proved Reserves | Proved plus Probable Reserves |
| 2015 | 104,669 | 128,068 | 313,837 | 313,837 | 418,506 | 441,905 |
| 2016 | 206,073 | 429,652 | 464,827 | 464,827 | 670,900 | 894,479 |
| 2017 | 202,350 | 442,098 | 569,130 | 569,130 | 771,480 | 1,011,228 |
| 2018 | 74,063 | 189,841 | 280,546 | 280,546 | 354,609 | 470,387 |
| 2019 | 26,635 | 69,754 | 60,367 | 60,367 | 87,002 | 130,121 |
| Remaining | 44,672 | 395,742 | 31,400 | 31,400 | 76,071 | 427,141 |
| Total (undiscounted) | 658,462 | 1,655,155 | 1,720,107 | 1,720,107 | 2,378,568 | 3,375,261 |

We expect to fund the development costs of our reserves through a combination of internally generated funds from operations, debt and equity financings. Planned activity levels vary each year due to factors such as capital availability, prevailing commodity prices, operational spacing considerations and regulatory processes.

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 Baytex Reserves 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.

**Possible Reserves**

We commissioned Ryder Scott to conduct an audit of our possible reserves effective December 31, 2014 in the Eagle Ford property. We have recognized 220.5 mmboe of possible reserves, representing 389 net well locations. The possible reserves reflect the significant upside potential of the Austin Chalk and Upper Eagle Ford formations. Possible reserves are those reserves that are less certain to be recovered than probable reserves.

**Contingent Resources**

We commissioned Sproule to conduct an assessment of contingent resources effective December 31, 2014 on two of our oil resource plays: the Bluesky in the Peace River area of Alberta and the Lower Cretaceous Mannville Group for the Gemini SAGD project. We also commissioned McDaniel & Associates Consultants Ltd. ("**McDaniel**") to conduct an assessment of contingent resources effective December 31, 2014 on the Lower Cretaceous Mannville Group in northeast Alberta.

Contingent resources 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. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

For the total of these three plays, Sproule and McDaniel's estimate of contingent resources ranges from 577 million barrels of oil equivalent and bitumen in the "low estimate" (C1) to 1,069 million barrels of oil equivalent and bitumen in the "high estimate" (C3), with a "best estimate" (C2) of 747 million barrels of oil equivalent and bitumen. Contingent resources are in addition to currently booked reserves.

The best estimate contingent resources of 747 million barrels of oil equivalent and bitumen represent an approximate six percent reduction in best estimate contingent resources from year-end 2013. Included in this reduction is 34 million barrels of oil equivalent best estimate contingent resources associated with our disposition of assets in the Williston Basin in North Dakota, USA. A further reduction of 8 million barrels of oil equivalent best estimate contingent resources is associated with surrendered lands in the Cold Lake property in Alberta. The remaining changes to our contingent resources assessment include land adjustments, transfer of reserves to resources and the conversion of resources to reserves during the year.

The table below summarizes Sproule and McDaniel's estimates of economic contingent resources for the three plays by geographic area. The contingent resources assessments were prepared in accordance with the definitions, standards and procedures contained in the COGE Handbook and NI 51-101.

**SUMMARY OF ECONOMIC CONTINGENT RESOURCES[1]**
**AS OF DECEMBER 31, 2014**

| | **Economic Contingent Resources (gross)[2][4][5]** | | |
|---|---|---|---|
| **(millions of barrels of oil equivalent and bitumen)[3]** | **Low[6]** | **Best[7]** | **High[8]** |
| Peace River, Alberta | 451 | 555 | 802 |
| Northeast Alberta | 62 | 118 | 183 |
| Gemini SAGD Project — Cold Lake, Alberta | 64 | 74 | 84 |
| Total | 577 | 747 | 1,069 |

Notes:

(1) Contingent resources are 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) Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

(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 resources at Peace River and the Gemini SAGD project that will be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resources is classified as bitumen under NI 51-101.

(4) Sproule and McDaniel prepared the estimates of contingent resources 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. The total volumes presented in the table are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of contingent resources and appreciate the differing probabilities of recovery associated with each class as explained herein.

(5) Gross means the company's working interest share in the contingent resources 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 in the low estimate have the highest degree of certainty — a 90% confidence level — that the actual quantities recovered will 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 in the best estimate have a 50% confidence level that the actual quantities recovered will 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 equal or exceed the high estimate. Those resources in the high estimate have a lower degree of certainty — a 10% confidence level — that the actual quantities recovered will equal or exceed the estimate.

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

## Other Oil and Gas Information

### *Oil and Natural Gas Properties*

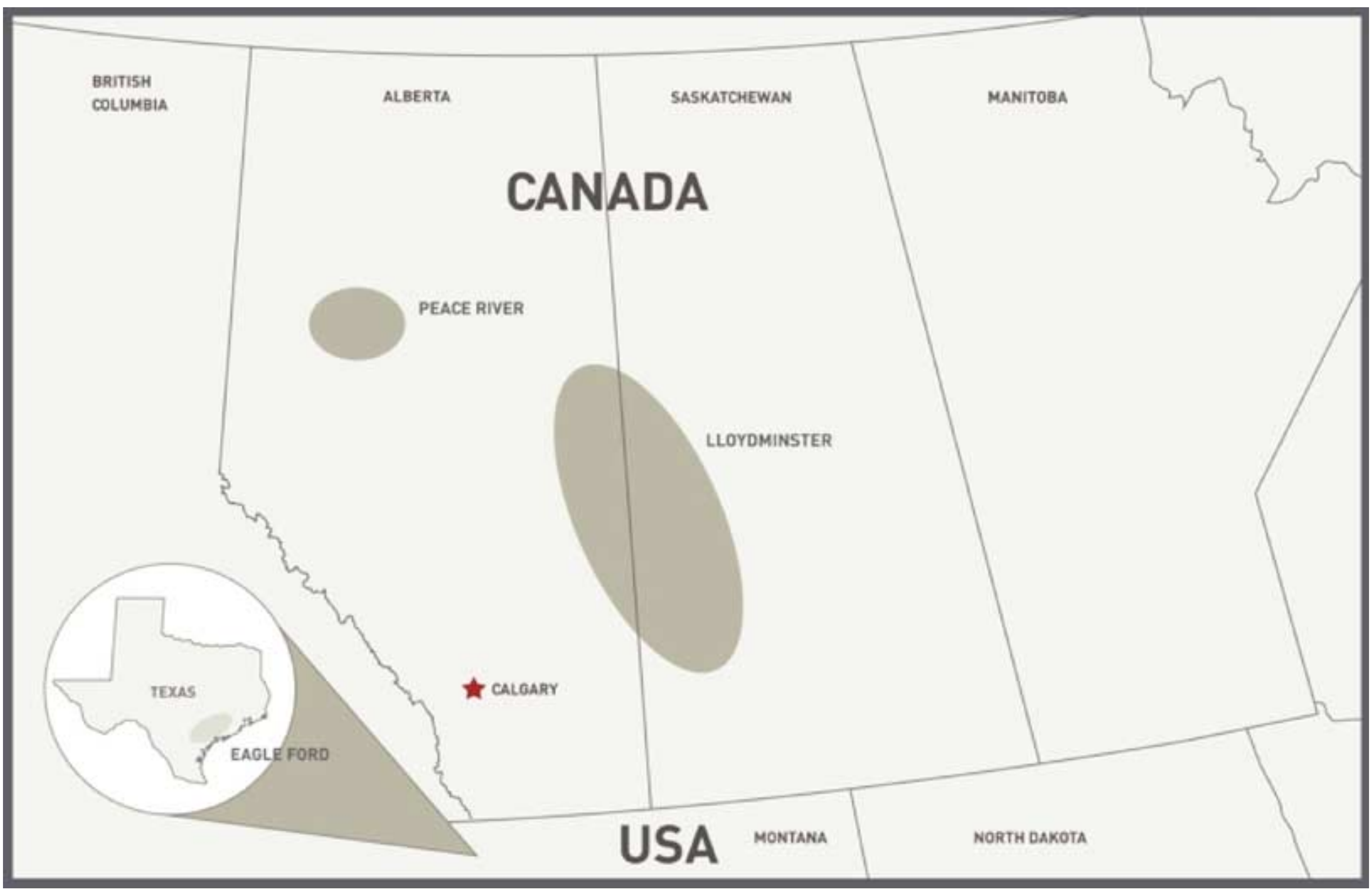
The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2014. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2014. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production for the year ended December 31, 2014, except where otherwise indicated.

Our crude oil and natural gas operations are organized into three business units: Central; Lloydminster; 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 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.

We will endeavour to continue to build value through internal property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area within the Central Business Unit and our historical area of emphasis around Northwest Saskatchewan and Northeast Alberta within the Lloydminster Business Unit. Future light oil development will focus on the Sugarkane area located in South Texas in the core of the liquids-rich Eagle Ford shale.

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

**Baytex Energy Corp. — Principal Properties**




*Lloydminster Business Unit*

The Lloydminster Business Unit accounted for approximately 24% of total production in 2014. The Lloydminster Business Unit's heavy oil operations include primary and thermal 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, directional/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 averages between 30 and 150 bbl/d of crude oil with gravities ranging from 10 to 16 degrees API. Once produced, the oil is delivered to markets in Canada and the United States via pipelines, tanker trucks or railways. Heavy crude is usually blended with light-hydrocarbon diluents prior to being introduced into a sales pipeline. The heavy crude Baytex delivers to rail for transport is not diluted. The blended (pipeline) and non-blended (rail) 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 oil only, before the addition of diluents.

In 2014, production in the Lloydminster Business Unit averaged approximately 19,403 boe/d, which was comprised of 16,185 bbl/d of heavy oil, 2,780 bbl/d of bitumen, and 2,623 Mcf/d of natural gas. During 2014, Baytex drilled 193 (111.4 net) wells in the Lloydminster Business Unit resulting in 172 (92.0 net) oil wells, 17 (17 net) stratigraphic and service wells and four (2.4 net) dry and abandoned wells, for a success rate of 97.7% (97.4% net). Our net undeveloped lands in the Lloydminster Business Unit totalled approximately 251,138 acres at year-end 2014.

The Lloydminster Business Unit possesses a large inventory of development projects within the operating areas of west-central Saskatchewan and Cold Lake/Ardmore in Alberta. Our ability to generate relatively low-cost replacement production through conventional cold production and enhanced recovery 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 maintain heavy oil production rates.

Listed below are brief descriptions of the principal properties within the Lloydminster Business Unit:

Cold Lake/Ardmore, Alberta: The majority of the Cold Lake and Ardmore assets were acquired in 2001 and 2002, respectively, and have been developed extensively for primary production in the General Petroleum, Sparky, McLaren and Colony formations. Average production from the primary assets during 2014 was approximately 1,541 bbl/d of heavy oil and 506 Mcf/d of natural gas (1,625 boe/d). Baytex drilled two (1.8 net) vertical and eight (8 net) horizontal oil wells in these areas in 2014.

On October 3, 2012, Baytex acquired a 100% working interest in 46 sections of undeveloped oil sands leases in the Angling Lake (Cold Lake) area of northern Alberta. The lands are proximal to our existing Cold Lake primary heavy oil assets and are prospective for both cold and thermal development. Regulatory approval has been obtained for the construction and operation on approximately 2.5 sections of the acquired lands of a two-stage bitumen recovery scheme using SAGD, which we refer to as the Gemini SAGD project. The first stage, being a single SAGD well pair pilot with a 600 metre horizontal lateral, was completed with steam circulation into the injector and producer commencing on January 24, 2014. The producing well was converted to production in May 2014. After the ramp-up, the average 30-day peak production rate was 923 bbl/d of bitumen. During the six months ended October 31, 2014, production averaged 690 bbl/d of bitumen with a steam-oil ratio of 2.23 barrels of steam per barrel of oil. In the fourth quarter of 2014, the artificial lift for the pilot well was changed from gas lift to a rod pump in order to increase the stability of the overall production system. In 2014, Baytex drilled 15 stratigraphic wells in the development area to fully delineate sufficient bitumen resource to support a commercial operation. In December 2014, with the information from the stratigraphic wells and revised facility engineering, Baytex submitted a scheme amendment application to the Alberta Energy Regulator to modify the facility size from 10,000 bbl/d to 5,000 bbl/d, change the produced water treatment design, utilize self-power generation and add two additional resource areas to the existing development approval. At year-end 2014, Baytex had 104,933 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. In 2014, 18 (17.4 net) horizontal wells (including 9 multi-laterals) were drilled, which, in combination with relatively low production declines due to strong performance of the ongoing waterflood, led to a year-over-year production increase. The waterflood was expanded in 2009, 2010, 2012 and 2014 (with further expansions planned for 2016 and beyond). Average production in 2014 was approximately 3,014 bbl/d of heavy oil and 223 Mcf/d of natural gas (3,051 boe/d). At year-end 2014, Baytex had 9,539 net undeveloped acres in this area.

Celtic, Saskatchewan: This property was acquired by Baytex in 2005. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons within the Mannville Group. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Baytex drilled 18 (18 net) oil wells in this area in 2014. Average production in 2014 was approximately 2,455 bbl/d of heavy oil and 141 Mcf/d of natural gas (2,479 boe/d). At year-end 2014, Baytex had 7,535 net undeveloped acres in this area.

Kerrobert/Hoosier, Saskatchewan: Baytex acquired most of its assets in the Kerrobert and Hoosier areas of Saskatchewan in 2009. These properties provide numerous opportunities for cold infill drilling and SAGD optimization. Production from the cold primary assets averaged approximately 1,247 bbl/d of heavy oil and 704 Mcf/d of natural gas (1,364 boe/d). Baytex drilled four (4 net) cold primary oil wells in this area in 2014. At year-end 2014, Baytex had 20,786 net undeveloped acres in this area.

At our Kerrobert SAGD project, Baytex drilled two new thermal infill wells, which commenced production in the third quarter of 2014 at average 30-day peak production rates of 430 bopd and 285 bopd, respectively. We project that through the remaining life of this project, we can drill up to eight additional SAGD well pairs and one additional infill well which provide us with 10 years of further reserve life. Average production from the Kerrobert SAGD project in 2014 was approximately 2,400 bbl/d of bitumen with a cumulative steam-oil ratio of 4.09 barrels of steam per barrel of oil and an instantaneous steam-oil ratio of 3.89 barrels of steam per barrel of oil from the pads where steam is currently being utilized.

Tangleflags, Saskatchewan: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. In 2014, Baytex drilled three (2.5 net) horizontal oil wells in the Lloydminster formation including one multi-lateral. Also in 2014, a commercial waterflood of the Lloydminster formation was initiated. Average production during 2014 was approximately 1,872 bbl/d of heavy oil and 309 Mcf/d of natural gas (1,923 boe/d). At year-end 2014, Baytex had 3,462 net undeveloped acres in this area.

*Central Business Unit*

The Central Business Unit produces light and heavy gravity crude oil, bitumen, natural gas and natural gas liquids from various fields, primarily in northern, southeast and central Alberta. This production accounted for approximately 46% of total Baytex production in 2014. During 2014, production from this business unit averaged 36,780 boe/d which was comprised of 25,318 bbl/d of heavy oil, 665 bbl/d of bitumen, 4,062 bbl/d of light oil and NGL and 40,414 Mcf/d of natural gas.

During 2014, Baytex drilled 64 (63.7 net) wells in the Central Business Unit resulting in 37 (36.7 net) oil wells, three (3.0 net) natural gas wells and 24 (24 net) stratigraphic/service wells, for a success rate of 100% (100% net). Our net undeveloped lands in this business unit totalled approximately 402,697 acres at year-end 2014.

Listed below are brief descriptions of the principal properties within the Central Business Unit:

Peace River, Alberta: Baytex holds a total of 310 net sections of oil sands leases in the Peace River area, which includes the legacy Seal area and the Reno area. During 2014, production from the Peace River area averaged 25,318 bbl/d of heavy oil, 665 bbl/d of bitumen and 2,498 Mcf/d of natural gas (26,399 boe/d). In 2014, Baytex drilled 31 (31 net) cold horizontal production wells and 24 (24 net) stratigraphic test wells in the Peace River area. The purpose of the stratigraphic test wells is to improve delineation of our land base and guide development well trajectories. At year-end 2014, Baytex had 163,559 net undeveloped acres in this area.

In certain parts of the Peace River land base, heavy oil can be produced using multi-lateral horizontal wells at initial production rates of approximately 400 bbl/d per well without employing more cost-intensive secondary and tertiary recovery methods. Reservoir analysis of the Peace River property has indicated that waterflood recovery method has the potential to increase economic oil reserves beyond what is achievable with cold primary recovery in some areas. Baytex has also demonstrated that cyclic steam stimulation ("**CSS**") can be successfully applied to areas of the Peace River oil sands.

Baytex has continued to progress its thermal CSS operation in the Cliffdale area of Peace River. A modified completion configuration was implemented in a portion of the Pad 1 CSS wells throughout the second half of 2014. The modified completion, combined with a refined steaming strategy, has demonstrated improved thermal conformance along the length of the horizontal wellbore. Production during the month of December 2014 averaged 767 barrels of oil per day with an instantaneous steam-oil ratio of 1.9 barrels of steam per barrel of oil. Overall, Pad 1 production and steam-oil ratio performance have continued to track predictions when incorporating downtime in the reservoir model.

Construction of the Pad 2 facility began early in the second quarter of 2013 with primary production start-up in the fourth quarter of 2013. The steam facility was commissioned late in the second quarter of 2014 after final environmental obligations were met. Experience from Pad 1 has shown the importance of establishing longitudinal steam conformance in early cycles. At this time, three of the fifteen wells at Pad 2 have been converted to thermal operations; all having similar completions to those at Pad 1. These wells will continue to be optimized in 2015. Once Baytex is confident in an appropriate early cycle operating strategy, the remaining 12 wells will be converted to CSS. Until then, these wells will continue to produce under primary conditions to create additional voidage to increase first cycle steam injectivity.

A pipeline and facility project will be commissioned in February 2015 to transport solution gas produced from our primary heavy oil wells in Harmon Valley to Cliffdale. This gas will be used to run the steam generators at Pad 1 and Pad 2, which will reduce operating costs.

In November 2014, Baytex submitted responses to the Supplemental Information Requests from the Alberta Energy Regulator, Alberta Environment and Sustainable Resource Development, and First Nations for the proposed expansion of Pads 3 and 4. These new pads would be constructed adjacent to the existing two pads, each having 15 CSS wells for a total of 55 CSS wells at Cliffdale.

<u>Pembina, Alberta:</u> Baytex acquired its initial position in Pembina in 2007 and further expanded its presence in the area through the acquisition of Burmis Energy Inc. in 2008. Production is primarily from the Cretaceous and Jurassic age formations, including the Cardium, Notikewin, Falher, Ellerslie, Glauconite, Rock Creek and Nordegg. The majority of Baytex's oil production in this area is treated at a Baytex-operated oil battery with the remaining production treated at third party-operated oil batteries. Natural gas production is delivered to a combination of four mid-stream gas processing facilities and three producer-operated gas processing facilities. Baytex owns a working interest in one of the midstream-operated gas processing facilities. Production from this area during 2014 averaged 1,617 bbl/d of light oil and NGL and 23,690 Mcf/d of natural gas. Baytex participated in the drilling of five (5 net) wells in this area in 2014, resulting in two (2 net) Cardium oil wells and three (3 net) natural gas wells (two Falher and one Notikewin), all of which were completed with multi-stage fracture stimulations. At year-end 2014, Baytex had 39,722 net undeveloped acres in this area.

*United States Business Unit*

On June 11, 2014, Baytex acquired an interest in approximately 80,200 (22,200 net) acres in the Sugarkane area located in South Texas in the core of the liquids-rich Eagle Ford shale through the acquisition of Aurora. Since the time of acquisition, Baytex has acquired additional acreage in Sugarkane, bringing the total land position to 22,978 net acres. See "General Development of Our Business — History and Development".

The acquired assets included both operated and non-operated assets. The non-operated assets included working interests in approximately 79,700 (20,100 net) acres within the Eagle Ford, comprising four areas of mutual interest (Sugarloaf, Longhorn, Ipanema and Excelsior), together with interests in wells, field infrastructure and related assets. These assets are operated by Marathon Oil EF LLC, a wholly-owned subsidiary of Marathon Oil Corporation (NYSE: MRO), pursuant to the terms of industry-standard joint operating agreements.

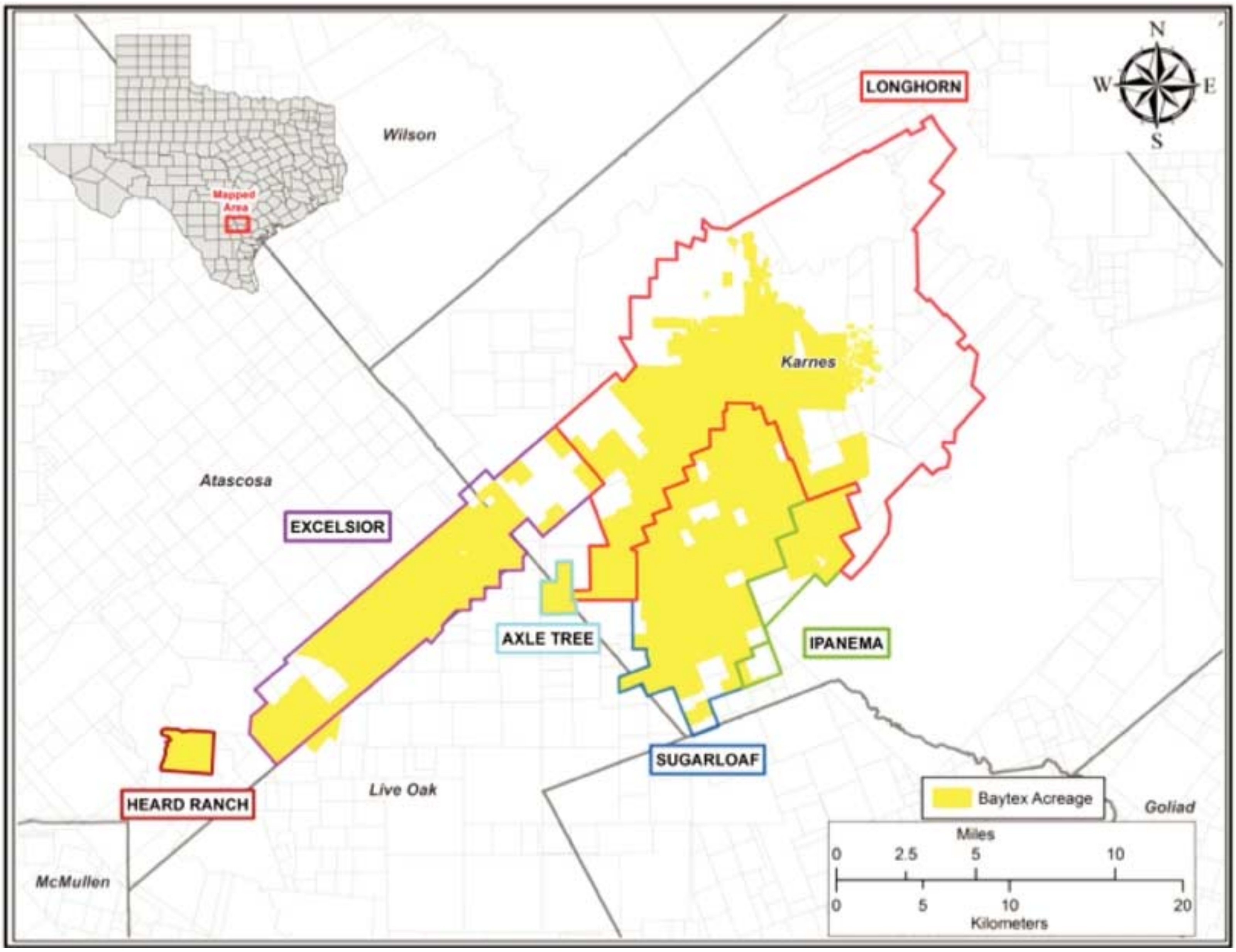
The operated assets included a 100% working interest in approximately 2,800 acres comprised of two separate blocks (Heard Ranch and Axle Tree Ranch), located within the liquids-rich zone of the Eagle Ford shale trend and are either adjacent or very proximate to the non-operated assets.

The acquired assets also included an acreage position along the Cretaceous play in East Texas which is regionally on trend with the Eagle Ford shale and other producing objectives. At year-end 2014, Baytex had 10,017 (9,751 net) undeveloped acres in East Texas in addition to 13,812 (gross and net) acres in New Mexico which are currently under evaluation.

The following table sets forth our gross and net acreage for all of our United States assets as at December 31, 2014:

| | Gross Acreage | Net Acreage |
|---|---|---|
| Sugarkane area: | | |
| Sugarloaf AMI | 24,126 | 6,763 |
| Longhorn AMI | 30,838 | 9,823 |
| Ipanema AMI | 4,771 | 1,737 |
| Excelsior AMI | 20,167 | 1,843 |
| Heard Ranch/Axle Tree (operated) | 2,811 | 2,811 |
| Total Sugarkane area | 82,713 | 22,978 |
| Other Eagle Ford | 87 | 8 |
| East Texas (operated) | 10,017 | 9,751 |
| New Mexico (operated) | 13,812 | 13,812 |
| Total | 106,629 | 46,549 |

The map below highlights the geographic location of our properties in the Sugarkane area:




Production from the non-operated assets is processed at 12 centralized processing facilities across the Sugarkane area, which provide the following capability:

- infield gathering systems between well locations and these centralized facilities;
- processing equipment for the treatment of natural gas and compression allowing injection into the transportation system that moves the product to gas processing plants where NGLs are separated from the gas;
- processing equipment for oil treatment and on site storage in preparation for either injection into oil pipelines that have contracted volumes and run across the field or for export via trucks to local refineries;
- saline water wells, centralized ponds and buried distribution pipework allowing water to be sent to fracture locations throughout our leasehold interests in the Sugarkane area and produced fracturing water to be recovered and recycled for future wells; and
- natural gas lift capability for longer term production maintenance of shallower wells in the volatile oil window.

On the Heard Ranch and Axle Tree Ranch properties, centralized processing facilities and gathering systems have been constructed to manage production from the development of these assets. In particular, the Axle Tree Ranch development includes amine treatment facilities to remove H2S, with the treated gas being used for gas lift and plant fuel. Untreated gas is sold through the Regency sour gas line which was commissioned in November 2013.

During the period from June 11, 2014 to December 31, 2014, production from the acquired assets averaged approximately 28,752 bbl/d of light oil and NGL and 38,487 Mcf/d of natural gas (35,166 boe/d). During this period, Baytex participated in the drilling of 132 (34.3 net) wells in the Sugarkane area, resulting in 69 (17.5 net) oil wells, 59 (15.7 net) natural gas wells, one (0.3 net) stratigraphic and service well and three (0.8 net) dry and abandoned wells, for a success rate of 97.7% (97.7% net).

In September, 2014, Baytex completed the sale of its assets in North Dakota for US$330.5 million. The disposed assets produced approximately 3,200 boe/d in the second quarter of 2014 and included 53.5 million boe of proved plus probable reserves (81% oil and NGL) as at December 31, 2013.

Production from the United States Business Unit in 2014 averaged 2,255 bbl/d of light and medium oil, 12,805 bbl/d of shale oil, 3,378 bbl/d of NGL, 21,511 Mcf/d of shale gas and 686 Mcf/d of natural gas (22,138 boe/d).

***Average Production***

The following table indicates our average daily production from our principal areas for the year ended December 31, 2014.

| | Heavy Oil (bbl/d) | Bitumen (bbl/d) | Light and Medium Oil (bbl/d) | Shale Oil (bbl/d) | NGL (bbl/d) | Shale Gas (Mcf/d) | Natural Gas (Mcf/d) | Oil Equivalent (boe/d) |
|---|---|---|---|---|---|---|---|---|
| **Lloydminster Business Unit** | | | | | | | | |
| Ardmore / Cold Lake / Sugden / Angling Lake | 1,541 | — | — | — | — | — | 506 | 1,625 |
| Carruthers | 3,014 | — | — | — | — | — | 223 | 3,051 |
| Celtic | 2,455 | — | — | — | — | — | 141 | 2,479 |
| Kerrobert / Hoosier | 1,247 | 2,388 | — | — | — | — | 704 | 3,753 |
| Tangleflags | 1,872 | — | — | — | — | — | 309 | 1,923 |
| Remaining properties | 5,534 | 392 | — | — | — | — | 740 | 6,050 |
| Divested properties | 522 | — | — | — | — | — | — | 522 |
| Total Lloydminster Business Unit | 16,185 | 2,780 | — | — | — | — | 2,623 | 19,403 |
| **Central Business Unit** | | | | | | | | |
| Peace River | 25,318 | 665 | — | — | — | — | 2,498 | 26,399 |
| Pembina | — | — | 612 | — | 1,005 | — | 23,690 | 5,565 |
| Remaining properties | — | — | 1,774 | — | 131 | — | 11,322 | 3,792 |
| Divested properties | — | — | 235 | — | 305 | — | 2,904 | 1,024 |
| Total Alberta Business Unit | 25,318 | 665 | 2,621 | — | 1,441 | — | 40,414 | 36,780 |
| **United States Business Unit** | | | | | | | | |
| Sugarkane (non-operated) | — | — | — | 11,503 | 3,106 | 20,462 | — | 18,020 |
| Sugarkane (operated) | — | — | — | 1,302 | 158 | 1,049 | — | 1,635 |
| Remaining properties | — | — | — | — | — | — | — | — |
| Divested properties | — | — | 2,255 | — | 114 | — | 686 | 2,483 |
| Total United States Business Unit | — | — | 2,255 | 12,805 | 3,378 | 21,511 | 686 | 22,138 |
| **Grand Total** | 41,503 | 3,445 | 4,876 | 12,805 | 4,819 | 21,511 | 43,723 | 78,321 |

***Costs Incurred***

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2014:

| **($000s)** | **Canada** | **United States** | **Total** |
|---|---|---|---|
| Property acquisition costs[1] | | | |
| Proved properties | 1,005 | 2,524,018 | 2,525,023 |
| Unproved properties | 10,948 | 392,315 | 403,263 |
| Property disposition[2] | (45,816) | (337,314) | (383,130) |
| Total Property acquisition costs, net | (33,863) | 2,579,019 | 2,545,156 |
| Development Costs[3] | 388,405 | 370,543 | 758,948 |
| Exploration Costs[4] | 5,823 | 1,299 | 7,122 |
| Total | 360,365 | 2,950,861 | 3,311,226 |

Notes:

(1) Property acquisition costs include the acquisition of Aurora Oil & Gas Limited.

(2) Property dispositions include the disposition of assets in North Dakota and in Canada.

(3) Development and facilities expenditures.

(4) Cost of geological and geophysical capital expenditures and drilling costs for 2014 exploratory wells drilled.

***Oil and Gas Wells***

The following table sets forth the number and status of wells in which we have a working interest as at December 31, 2014.

| | **Oil Wells** | | | | **Natural Gas Wells** | | | |
|---|---|---|---|---|---|---|---|---|
| | **Producing** | | **Non-Producing** | | **Producing** | | **Non-Producing** | |
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Alberta | 1,049 | 696.6 | 1,018 | 603.0 | 435 | 325.7 | 492 | 377.7 |
| Saskatchewan | 938 | 903.8 | 1,308 | 1,236.6 | 38 | 33.1 | 110 | 98.5 |
| Texas | 410 | 109.1 | 37 | 8.2 | 167 | 43.7 | 52 | 14.8 |
| Total | 2,397 | 1,709.5 | 2,363 | 1,847.8 | 640 | 402.5 | 654 | 491.0 |

### *Undeveloped Land Holdings*

The following table sets forth our undeveloped land holdings as at December 31, 2014.

| | Undeveloped Acres | |
|---|---|---|
| | Gross | Net |
| **Canada** | | |
| Alberta | 588,805 | 506,150 |
| British Columbia | 660 | 26 |
| Saskatchewan | 140,725 | 133,730 |
| Total Canada | 730,190 | 639,906 |
| | | |
| **United States** | | |
| New Mexico | 13,812 | 13,812 |
| Texas (Eagle Ford) | 2,170 | 316 |
| Texas (East Texas) | 10,017 | 9,751 |
| Total United States | 25,999 | 23,879 |
| Grand Total | 756,189 | 663,785 |

We estimate the value of our net undeveloped land holdings at December 31, 2014 to be approximately $201 million, as compared to $281 million at December 31, 2013. 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 20,850 net acres of our undeveloped land holdings may expire on or before December 31, 2015. There are no material drilling commitments associated with the land holdings expiring by December 31, 2015.

### *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, 2014.

| | Exploratory Wells | | Development Wells | | Total Wells | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| Oil | — | — | 292 | 153.4 | 292 | 153.4 |
| Natural Gas | — | — | 62 | 18.7 | 62 | 18.7 |
| Evaluation | 39 | 39.0 | — | — | 39 | 39.0 |
| Service | — | — | 3 | 2.3 | 3 | 2.3 |
| Dry | — | — | 7 | 3.2 | 7 | 3.2 |
| Total | 39 | 39.0 | 364 | 177.6 | 403 | 216.6 |

### *Forward Contracts*

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2014, see Note 22 to our audited consolidated financial statements for the year ended December 31, 2014.

### *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 expects to pay cash income taxes in 2015 at an effective tax rate of approximately 5% of funds from operations. This estimate is highly sensitive to assumptions regarding commodity prices, production, funds from operations and capital expenditure levels. As at December 31, 2014, Baytex's total Canadian tax pools were estimated to be $1.4 billion and total United States tax pools were estimated to be $1.5 billion.

***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 ($ thousands) | Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($ thousands) |
|---|---|---|
| Total liability as at December 31, 2014 | 693,389 | 68,378 |
| Anticipated to be paid in 2015 | 10,935 | 10,421 |
| Anticipated to be paid in 2016 | 10,163 | 8,811 |
| Anticipated to be paid in 2017 | 8,160 | 6,430 |

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. No estimate of salvage value is netted against the estimated cost. Using public data and our own experience, we estimate the amount and timing of future abandonment and reclamation expenditures at an operating area level. Wells within each operating area are assigned an average cost per well to abandon and reclaim the well. The estimated expenditures are based on current regulatory standards and actual abandonment cost history.

The number of net wells for which we estimated we will incur reclamation and abandonment costs is 4,090 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 591 wells which are all the proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2014. Abandonment and reclamation costs have been estimated over a 50-year period. Facility reclamation costs are scheduled to be incurred two years following the end of the reserve life of the 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 $693.4 million ($68.4 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, 2015, 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*".

| | Heavy Oil (bbl/d) | Bitumen (bbl/d) | Light and Medium Oil (bbl/d) | Shale Oil (bbl/d) | NGL (bbl/d) | Shale Gas (Mcf/d) | Natural Gas (Mcf/d) | Oil Equivalent (boe/d) |
|---|---|---|---|---|---|---|---|---|
| **CANADA** | | | | | | | | |
| Total Proved | 34,528 | 3,558 | 1,698 | — | 1,171 | — | 32,534 | 46,377 |
| Total Proved plus Probable | 38,309 | 3,960 | 1,823 | — | 1,284 | — | 37,329 | 51,598 |
| **UNITED STATES** | | | | | | | | |
| Total Proved | — | — | — | 14,561 | 16,964 | 35,086 | 14,580 | 39,802 |
| Total Proved plus Probable | — | — | — | 15,078 | 17,704 | 35,770 | 15,961 | 41,404 |
| **TOTAL** | | | | | | | | |
| Total Proved | 34,528 | 3,558 | 1,698 | 14,561 | 18,134 | 35,086 | 47,114 | 86,179 |
| Total Proved plus Probable | 38,309 | 3,960 | 1,823 | 15,078 | 18,989 | 35,770 | 53,289 | 93,002 |

The two properties that account for 20% or more of the estimated 2015 production volumes are the Eagle Ford and Peace River (cold primary production). Estimated 2015 production volumes for Eagle Ford are 39,802 boe/d on a total proved basis and 41,404 boe/d on a total proved plus probable basis. Estimated 2015 production volumes for Peace River (cold primary production) are 21,843 boe/d on a total proved basis and 23,578 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, 2014 | Sept 30, 2014 | June 30, 2014 | Mar. 31, 2014 | Dec. 31, 2014 |
| **Average Sales Volume**[1] | | | | | |
| Heavy Oil (bbl/d) | 39,805 | 41,766 | 42,730 | 42,017 | 41,577 |
| Bitumen (bbl/d) | 3,380 | 3,726 | 3,514 | 3,158 | 3,446 |
| Light Oil (bbl/d) | 2,507 | 5,812 | 5,751 | 5,471 | 4,876 |
| NGL (bbl/d) | 8,098 | 6,628 | 2,476 | 1,986 | 4,819 |
| Shale Oil (bbl/d) | 24,409 | 22,313 | 4,112 | — | 12,805 |
| Shale Gas (Mcf/d) | 41,380 | 37,577 | 6,443 | — | 21,510 |
| Natural Gas (Mcf/d) | 43,048 | 45,723 | 45,202 | 40,886 | 43,724 |
| Total (boe/d) | 92,271 | 94,137 | 67,191 | 59,446 | 78,395 |
| **Average Net Production Prices Received** | | | | | |
| Heavy Oil ($/bbl) | 52.92 | 73.62 | 78.88 | 70.74 | 69.26 |
| Bitumen ($/bbl) | 58.29 | 78.05 | 83.75 | 76.39 | 74.24 |
| Light Oil ($/bbl) | 88.97 | 104.49 | 111.09 | 95.79 | 107.64 |
| NGL ($/bbl) | 28.06 | 36.77 | 38.74 | 55.93 | 35.28 |
| Shale Oil ($/bbl) | 77.86 | 101.23 | 110.72 | — | 90.75 |
| Shale Gas ($/Mcf) | 4.36 | 4.69 | 5.09 | — | 4.56 |
| Natural Gas ($/Mcf) | 3.89 | 4.22 | 4.81 | 5.22 | 4.52 |
| Total ($/boe) | 53.72 | 72.04 | 75.06 | 68.33 | 66.54 |
| **Royalties Paid** | | | | | |
| Heavy Oil ($/bbl) | 9.40 | 16.68 | 20.25 | 15.37 | 15.51 |
| Bitumen ($/bbl) | 4.41 | 0.44 | 11.65 | 6.93 | 5.73 |
| Light Oil and NGL ($/bbl)[2] | 15.08 | 23.57 | 23.19 | 21.53 | 20.77 |
| Shale Oil ($/bbl) | 19.49 | 25.14 | 27.65 | — | 22.63 |
| Shale Gas ($/Mcf) | 1.75 | 2.11 | 1.43 | — | 1.88 |
| Natural Gas ($/Mcf) | 0.03 | 0.19 | 0.31 | 0.10 | 0.16 |
| Total ($/boe) | 11.90 | 17.43 | 18.36 | 14.00 | 15.35 |
| **Operating Expenses**[3][4] | | | | | |
| Heavy Oil ($/bbl) | 12.91 | 11.02 | 10.93 | 10.37 | 11.29 |
| Bitumen ($/bbl) | 25.15 | 25.61 | 24.53 | 27.29 | 25.60 |
| Light Oil and NGL ($/bbl)[2] | 16.24 | 14.95 | 17.39 | 18.81 | 16.55 |
| Shale Oil ($/bbl)[5] | 12.86 | 10.77 | 7.99 | — | 11.55 |
| Shale Gas ($/Mcf)[5] | — | — | — | — | — |
| Natural Gas ($/Mcf) | 2.54 | 1.96 | 2.47 | 2.51 | 2.36 |
| Total ($/boe) | 12.95 | 11.39 | 12.51 | 12.87 | 12.37 |
| **Transportation Expenses** | | | | | |
| Heavy Oil ($/bbl) | 4.06 | 4.37 | 4.64 | 5.83 | 4.73 |
| Bitumen ($/bbl) | 5.55 | 7.59 | 6.32 | 6.00 | 6.41 |
| Light Oil and NGL ($/bbl)[2] | 0.29 | 0.29 | 0.46 | 0.39 | 0.34 |
| Shale Oil ($/bbl)[5] | — | — | — | — | — |
| Shale Gas ($/Mcf)[5] | — | — | — | — | — |
| Natural Gas ($/Mcf) | 0.17 | 0.17 | 0.17 | 0.18 | 0.17 |
| Total ($/boe) | 2.07 | 2.36 | 3.45 | 4.61 | 2.93 |

| | Three Months Ended | | | | Year Ended |
|---|---|---|---|---|---|
| | Dec. 31, 2014 | Sept 30, 2014 | June 30, 2014 | Mar. 31, 2014 | Dec. 31, 2014 |
| **Netback Received**[6] | | | | | |
| Heavy Oil ($/bbl) | 26.55 | 41.55 | 43.07 | 39.18 | 37.73 |
| Bitumen ($/bbl) | 23.18 | 44.41 | 41.25 | 36.17 | 36.50 |
| Light Oil and NGL ($/bbl)[2] | 6.51 | 24.51 | 40.15 | 44.45 | 26.64 |
| Shale Oil ($/bbl) | 45.50 | 65.32 | 75.08 | — | 56.57 |
| Shale Gas ($/Mcf) | 2.61 | 2.59 | 3.67 | — | 2.68 |
| Natural Gas ($/Mcf) | 1.16 | 1.89 | 1.86 | 2.43 | 1.83 |
| Total ($/boe) | 26.80 | 40.86 | 40.74 | 36.85 | 35.89 |
| Financial Derivatives gain (loss) ($/boe)[7] | 6.48 | (0.47) | (2.28) | (0.30) | 1.24 |
| Netback Received after hedging ($/boe) | 33.28 | 40.39 | 38.46 | 36.55 | 37.13 |

Notes:

(1) Before deduction of royalties.
(2) All NGL volumes are grouped with Canadian light oil and NGL for royalties paid and operating expenses 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) Operating and transportation expenses split for costs between shale oil and shale gas are not available for Eagle Ford.
(6) Netback is calculated by subtracting royalties, operating expenses, transportation expenses and losses/gains on commodity and foreign exchange contracts from revenues.
(7) Financial derivatives reflect realized gains (losses) on commodity-related contracts only.

***Marketing Arrangements***

Baytex markets 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. In response to market conditions, sales of undiluted bitumen to rail loading facilities plateaued in 2014, representing a significant position within Baytex's market access portfolio.

*Oil and NGL*

For the year ended December 31, 2014, the prompt price settlements of West Texas Intermediate crude oil fluctuated between a high of US$107.26/bbl and a low of US$53.27/bbl, with an average price of US$92.97/bbl. The volatile price range seen in 2014 reflected strong prices through the first half of the year, falling steadily through the second half as OPEC relinquished its traditional swing producer role in favor of a market share strategy, setting a target production level for the group of 30 million bbl/d.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("**WCS**") price differential to WTI, averaged 21% for the year ended December 31, 2014, as compared to an average of 26% for the year ended December 31, 2013. WCS price differential volatility diminished greatly in 2014 as both pipeline and rail take away capacity expanded significantly through the year, allowing WCS to access U.S. and Canadian markets and avoid periods of market dislocation seen in previous years.

For 2014, Baytex's heavy oil sales prices averaged $69.64/bbl, while light oil and condensate prices averaged $91.37/bbl. In contrast, for 2013 Baytex averaged $65.24/bbl for heavy oil sales and $90.31/bbl for light oil and condensate sales. Baytex's NGL price in 2014 was $35.28/bbl, as compared with $42.63/bbl in 2013.

In 2014, Baytex sold its North Dakota production and purchased higher valued production in the Eagle Ford. This change resulted in Baytex's U.S. light oil and condensate price realizations averaging $91.63/bbl in 2014, essentially unchanged from 2013 ($92.20/bbl), notwithstanding that the average annual price for the WTI benchmark decreased by 5% (from $97.97/bbl in 2013 to $92.97/bbl in 2014).

*Natural Gas*

For the year ended December 31, 2014, the average AECO natural gas price was $4.42/Mcf, as compared to $3.13/Mcf in the same period of 2013. The increase in the natural gas price was due to colder than normal weather driving up natural gas demand in the winter months, which resulted in significant U.S. and western Canada storage draws. For 2014, Baytex's average physical natural gas sales price was $4.53/Mcf, as compared to $3.32/Mcf in 2013.

***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, 2014, 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 |
|---|---|---|---|
| **James L. Bowzer**<br>Calgary, Alberta | 54 | Director, President and Chief Executive Officer | President and Chief Executive Officer of Baytex |
| **John A. Brussa**(3)(4)<br>Calgary, Alberta | 57 | Director | Vice Chairman of Burnet, Duckworth & Palmer LLP |
| **Raymond T. Chan**<br>Calgary, Alberta | 59 | Director and Chairman of the Board | Chairman of the Board of Baytex |
| **Edward Chwyl**(2)(3)(4)<br>Victoria, B.C. | 71 | Director | Independent Businessman |
| **Naveen Dargan**(1)(2)<br>Calgary, Alberta | 57 | Director | Independent Businessman |
| **R.E.T. (Rusty) Goepel**(4)<br>Vancouver, B.C. | 72 | Director | Senior Vice President of Raymond James Ltd. |
| **Gregory K. Melchin**(1)<br>Calgary, Alberta | 61 | Director | Independent Businessman |
| **Mary Ellen Peters**(1)(2)<br>Highland, Michigan | 58 | Director | Independent Businesswoman |
| **Dale O. Shwed**(3)<br>Calgary, Alberta | 56 | Director | President and Chief Executive Officer of Crew Energy Inc. |
| **Kendall D. Arthur**<br>Calgary, Alberta | 34 | Vice President, Lloydminster Business Unit | Vice President, Lloydminster Business Unit of Baytex |
| **Geoffrey J. Darcy**<br>Calgary, Alberta | 52 | Senior Vice President, Marketing | Senior Vice President, Marketing of Baytex |
| **Murray J. Desrosiers**<br>Calgary, Alberta | 45 | Vice President, General Counsel and Corporate Secretary | Vice President, General Counsel and Corporate Secretary of Baytex |
| **Brian G. Ector**<br>Calgary, Alberta | 46 | Senior Vice President, Capital Markets and Public Affairs | Senior Vice President, Capital Markets and Public Affairs of Baytex |
| **Rodney D. Gray**<br>Calgary, Alberta | 43 | Chief Financial Officer | Chief Financial Officer of Baytex |
| **Neal E. Halstead**<br>Calgary, Alberta | 46 | Vice President, Finance and Controller | Vice President, Finance and Controller of Baytex |
| **Cameron A. Hercus**<br>Calgary, Alberta | 45 | Vice President, Corporate Development | Vice President, Corporate Development of Baytex |
| **Ryan M. Johnson**<br>Calgary, Alberta | 38 | Vice President, Central Business Unit | Vice President, Central Business Unit of Baytex |

| Name and Municipality of Residence | Age | Position with Baytex | Principal Occupation |
|---|---|---|---|
| **Mark A. Montemurro**<br>Calgary, Alberta | 54 | Vice President, Thermal Projects | Vice President, Thermal Projects of Baytex |
| **Richard P. Ramsay**<br>Calgary, Alberta | 51 | Chief Operating Officer | Chief Operating Officer of Baytex |
| **Gregory A. Sawchenko**<br>Calgary, Alberta | 42 | Vice President, Land | Vice President, Land of Baytex |
| **Michael L. Verm**<br>Houston, Texas | 56 | Vice President,<br>U.S. Business Unit | Vice President,<br>U.S. 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).

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

*James L. Bowzer* was appointed President, Chief Executive Officer and director of both Baytex and Baytex Energy on September 4, 2012. Mr. Bowzer has over 30 years of global experience leading large organizations, directing new projects and developing successful leaders. From November 2008 to August 2012, he was Vice President, North American Production Operations for Marathon Oil Corporation ("**Marathon**") in Houston, Texas. In this role he was responsible for Marathon's expansive domestic portfolio, which included unconventional plays in the Bakken, Eagle Ford, Niobrara and Anadarko Woodford in the United States and heavy oil in Canada, and conventional plays in Alaska, Colorado, Louisiana, Oklahoma, Texas and Wyoming. From May 2006 to November 2008, Mr. Bowzer was Regional Vice President, International Production at Marathon where he was responsible for a diverse mix of significant businesses in Norway, the United Kingdom, Ireland and Africa. Prior thereto, he held senior positions at Marathon in strategic planning and business development. Mr. Bowzer has a Bachelor of Science degree in Petroleum Engineering from the University of Wyoming and completed the Advanced Management Program at the Graduate School of Business at Indiana University. He has served on the board of directors of several industry and professional associations, including a term on the Board of Directors for the University of Wyoming, School of Energy Resources. He is currently a member of the Board of Governors of the Canadian Association of Petroleum Producers.

*John A. Brussa* became a Director of Baytex on December 31, 2010 and served as a director of Baytex Energy from October 1997 to December 2014. He is the Vice Chairman of Burnet, Duckworth & Palmer LLP and focuses on tax law. He was admitted to the Alberta bar in 1982. He holds a Bachelor of Laws degree and a Bachelor of Arts, History and Economics degree from the University of Windsor.

*Raymond T. Chan* was appointed Chairman of the Board of Baytex on June 1, 2014. He originally joined Baytex in October 1998 and has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to August 2003); President (September 2003 to November 2007); Chief Executive Officer (September 2003 to December 2008); Interim Chief Executive Officer (May 2012 to September 2012) and Executive Chairman (January 2009 to May 2014). Mr. Chan served as a director of Baytex Energy from October 1998 to December 2014. 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 served as a director of Baytex Energy from May 2003 to December 2014. 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 of 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 served as a director of Baytex Energy from September 2003 to December 2014. 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 Tervita Corporation. He holds a Bachelor of Arts (Honours) degree in Mathematics and Economics from Queen's University, a Master of Business Administration degree from the Schulich School of Business at York University and a Chartered Business Valuator designation.

*R.E.T. (Rusty) Goepel* became a Director of Baytex on December 31, 2010 and served as a director of Baytex Energy from May 2005 to December 2014. 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 is a director of Telus Corporation and Amerigo Resources Ltd. He is past Chairman of the Vancouver 2010 Winter Olympics and The Business Council of British Columbia. He is a recipient of the Queen's Gold and Diamond Jubilee Medals for service to the community, financial industry and business. Mr. Goepel holds a Bachelor of Commerce (Honours) degree from the University of British Columbia.

*Gregory K. Melchin* became a director of Baytex on December 31, 2010 and served as a director of Baytex Energy from May 2008 to December 2014. He is currently the Chairperson of the board of directors 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.

*Mary Ellen Peters* became a Director of Baytex and served as a director of Baytex Energy from July 2013 to December 2014. She holds a Bachelor of Science degree (major in finance) and a Master of Business Administration degree. She has also completed executive management programs at Penn State University and Indiana University and the Oxford Energy Seminar. She is a retired businesswoman with over 30 years of experience in the petroleum industry, most notably as Senior Vice President, Transportation and Logistics from 2009-2010 and Senior Vice President, Marketing from 1998-2009 at Marathon Petroleum Company LP. Prior thereto, she held various technical and management positions with Marathon. Peters' previous board experience includes acting as Chairman of the Board of Managers for Louisiana Offshore Oil Port and as a director of Colonial Pipeline Company.

*Dale O. Shwed* became a Director of Baytex on December 31, 2010 and served as a director of Baytex Energy from June 1993 to December 2014. 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.

*Kendall D. Arthur* was appointed Vice President, Lloydminster Business Unit of Baytex on March 4, 2015. Mr. Arthur has over 10 years of experience in the Canadian oil and gas industry. He joined Baytex Energy in 2006 as a Production Engineer in the Heavy Oil Business Unit and held the position of Vice President, Saskatchewan Business Unit from January 2012 to March 2015. 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.

*Geoffrey J. Darcy* was appointed Senior Vice President, Marketing of Baytex on May 21, 2014 and is responsible for maximizing the value of our products and managing our commodity price risk exposures. He joined Baytex in September 2011 and held the position of Vice President, Marketing from September 2011 to May 2014. Prior thereto, he was Director of North American Physical Crude Oil Trading for Barclays Bank. Mr. Darcy has over 25 years of 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. Mr. Darcy holds 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 Senior Vice President, Capital Markets and Public Affairs of Baytex on May 21, 2014 and is responsible for Baytex's equity capital markets, investor relations and public affairs functions. He joined Baytex in November 2009 and has held the following positions: Director of Investor Relations from November 2009 to June 2011, Vice President, Investor Relations from June 2011 to March 2014 and Vice President, Capital Markets from April 2014 to May 2014. Prior to joining Baytex, Mr. Ector spent 15 years as a sell-side research analyst covering both energy trusts and exploration and production corporations. Mr. Ector received a Bachelor of Commerce degree with a concentration in finance from the University of Calgary and received his Chartered Financial Analyst designation in 1996. He is a national board member of the Canadian Investor Relations Institute as well as a member of the National Investor Relations Institute, the CFA Institute and the Calgary CFA Society.

*Rodney D. Gray* was appointed Chief Financial Officer of Baytex on April 7, 2014. Mr. Gray has over twenty years' experience in the oil and gas industry. Prior to joining Baytex, Mr. Gray held the position of Chief Financial Officer for CEDA International since July, 2013. Prior thereto, he spent eleven years with Enerplus Corporation, including the last eight as Vice President, Finance where he was responsible for corporate reporting, treasury and capital markets, operational accounting, business analysis, risk management and insurance. Mr. Gray is a Chartered Accountant and has a Bachelor of Commerce degree with Honours from Queen's University.

*Neal E. Halstead* was appointed Vice President, Finance and Controller of Baytex on April 1, 2014 and is responsible for Baytex's financial reporting and compliance, internal controls, and operational accounting. He originally joined Baytex in May 2013 as Controller. Prior to joining Baytex, Mr. Halstead was the Controller at Sasol Canada Holdings Ltd. Prior thereto, he was Vice President, Finance (Canadian Plains Division) at Cenovus Energy and previously, Assistant Controller, U.K. Finance at Encana Corporation in London, England. Mr. Halstead has also held a variety of positions with Encana Corporation, PanCanadian Petroleum, CP Rail, Trizec Properties and Ernst & Young. Mr. Halstead has over 20 years of experience in the Canadian and international oil and gas industry and holds a Bachelor of Commerce with Great Distinction from the University of Saskatchewan and is a member of the Canadian Institute of Chartered Accountants and the Institute of Chartered Accountants of Alberta.

*Cameron A. Hercus* was appointed Vice President, Corporate Development of Baytex on May 21, 2013 and is responsible for evaluating acquisition opportunities and developing our long range growth plans. Mr. Hercus is a Petroleum Engineer with over 20 years of experience in the Canadian and European oil and gas industry. Prior to joining Baytex, he spent five years working with Vermilion Energy Inc. in business development, new ventures and exploitation roles evaluating and developing opportunities in Western Canada and Europe. Prior thereto, he worked with Marathon, Shell and Paladin Resources where he developed a strong background in reservoir engineering and field development while working in the UK North Sea. Mr. Hercus has a Bachelor of Science degree in Geology and Petroleum Geology (Honors) from the University of Aberdeen and completed a Master of Science degree in Petroleum Engineering from Heriot-Watt University in 1995.

*Ryan M. Johnson* was appointed Vice President, Central Business Unit of Baytex on March 4, 2015. Mr. Johnson joined Baytex in 2007 focusing on technical responsibilities in northeast Alberta and southern Saskatchewan, including the planning and execution of Baytex's successful thermal SAGD project at Kerrobert. In January 2011, he was appointed Senior Geologist of the Peace River region and has been an integral member of the team responsible for the planning, coordination and execution of multi-lateral exploitation and thermal development of this resource. In mid-2013, Mr. Johnson was appointed Lead Geologist and charged with managing all key activities across the entire Alberta/B.C. Business Unit. In May 2014, Mr. Johnson was appointed Vice President, Alberta/B.C. Business Unit. Mr. Johnson has over 15 years of extensive technical and managerial roles in oil and gas exploration, development, operations and prospect identification. Mr. Johnson has a Bachelor of Science Degree (Honours) in Geology and Oceanography from the University of British Columbia and is a practicing member of the Association of Professional Engineers and Geoscientists of Alberta.

*Mark A. Montemurro* was appointed Vice President, Thermal Projects of Baytex on November 11, 2013. Mr. Montemurro has over 30 years of experience in the Canadian oil and gas industry, including significant thermal project experience. Prior to joining Baytex, he has held a variety of executive positions, primarily leading subsurface, facility and operations teams with Sunshine Oilsands Ltd., Laricina Energy Limited, Deer Creek Energy Limited and PanCanadian Energy Corporation. He also co-founded Alter NRG, a Canadian public alternate energy company involved in plasma gasification. He holds a Bachelor of Science degree in Chemical Engineering from the University of Calgary and is a practicing member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta.

*Richard P. Ramsay* was appointed Chief Operating Officer of Baytex on May 21, 2014. He originally joined Baytex in January 2010 and has held the following positions: Vice President, Heavy Oil from January 2010 to January 2012 and Vice President, Alberta/B.C. Business Unit from January 2012 to May 2014. Mr. Ramsay has over 25 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.

*Gregory A. Sawchenko* was appointed Vice President, Land of Baytex on August 12, 2013. Mr. Sawchenko has over 15 years of experience in oil and gas land management and negotiations. Prior to joining Baytex, he was most recently the Land Manager for Crescent Point Energy Corp. At Crescent Point, Mr. Sawchenko was an instrumental member in many key transactions and contributed to the growth of the company. Early in his career, he held positions with successive levels of responsibility at Numac Energy Inc., Anderson Exploration Ltd., Devon Canada Corporation and EnCana Corporation. Mr. Sawchenko holds a Bachelor of Commerce degree from the University of Calgary with a designation in Petroleum Land Management and is a member of the Canadian Association of Petroleum Landmen.

*Michael L. Verm* was appointed Vice President, U.S. Business Unit of Baytex on December 8, 2014. In this role he is also President of Baytex's primary U.S. operating entity, Baytex Energy USA, Inc., which is based in Houston, Texas. He originally joined Baytex on June 11, 2014 as Vice President, Eagle Ford Operations.

Mr. Verm has over 30 years of experience in the oil and gas industry and has held a number of senior executive positions in North America and internationally. Mr. Verm served as Chief Operating Officer of Aurora Oil & Gas Limited from June 2011 to June 2014. Mr. Verm has a Bachelor of Science degree in petroleum engineering from Texas A&M and a Master of Business Administration degree from Oklahoma City University and is a registered professional engineer in Texas.

***Ownership of Securities by Management***

As at March 2, 2015, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,818,308 Common Shares, representing approximately 1.1 percent of the issued and outstanding Common Shares and $80,000 principal amount of 2022 Debentures.

***Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions***

**Other than as disclosed below, 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.

Mr. Brussa, a director of Baytex, was formerly a director of Calmena Energy Services Inc. (a public oilfield service company) which was placed in receivership on January 20, 2015. Mr. Brussa resigned as a director of Calmena on June 30, 2014.

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 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 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 Committee's Mandate and Terms of Reference is attached as Appendix C.

### Composition of the Audit Committee

The members of our Audit Committee are Naveen Dargan, Gregory K. Melchin and Mary Ellen Peters, 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. |
| 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. |
| Mary Ellen Peters | Yes | Yes | Bachelor of Science degree (major in finance) and a Master of Business Administration degree. Also completed the Penn State Executive Leadership Program. Retired businesswoman with over 30 years of experience in the petroleum industry, most notably as Senior Vice President, Transportation and Logistics (2009-2010) and Senior Vice President, Marketing (1998-2009) at Marathon Petroleum Company, LP. |

### 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 LLP, our external auditors, during fiscal 2014 and 2013:

| | Aggregate fees billed ($000s) | |
|---|---|---|
| | 2014 | 2013 |
| Audit Fees | $ 1,584 | $ 1,056 |
| Audit-Related Fees | — | — |
| Tax Fees | — | 21 |
| All Other Fees | — | — |
| | $ 1,584 | $ 1,077 |

*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 financial statements, services in this category for fiscal 2014 and 2013 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 and reviews of a base shelf prospectus, a prospectus related to a public offering of subscription receipts and an offering memorandum related to a private placement of senior notes.

*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 equally 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 percent 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.

**Senior Notes**

On February 17, 2011, we issued US$150 million principal amount of 6.75% series B senior unsecured debentures due February 21, 2021. The 2021 Debentures pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on February 17, 2016 at the redemption prices specified in Debt Indenture #1.

On July 19, 2012, we issued $300 million principal amount of 6.625% series C senior unsecured debentures due July 19, 2022. The 2022 Debentures pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on July 19, 2017 at the redemption prices specified in Debt Indenture #1.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 and US$400 million of 5.625% notes due June 1, 2024. The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at the Company's option, in whole or in part, commencing on June 1, 2017 (in the case of the 2021 Notes) and June 1, 2019 (in the case of the 2024 Notes) at the redemption prices specified in Debt Indenture #2.

For a complete description of the Senior Notes, reference should be made to the applicable debt indenture, copies of which are accessible on the SEDAR website at *www.sedar.com*. See "*Material Contracts*".

**Credit Facilities**

As at March 1, 2015, we had established revolving extendible unsecured credit facilities consisting of a $50 million operating loan and a $950 million syndicated loan for us and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex USA. Unless extended, the revolving period under the Credit Facilities will end on June 4, 2018 with all amounts to be re-paid on such date. We may, once in each calendar year, request that the lenders under the Credit Facilities extend the revolving period for up to four years (subject to a maximum four-year term at any time). The Credit Facilities do not require any mandatory principal payments prior to maturity and do not include a term-out feature or a borrowing base restriction. The Credit Facilities include an option allowing such facilities to be increased by up to $250 million, subject to existing or new lender(s) providing commitments for any such increase.

The Credit Facilities contain standard commercial covenants for facilities of this nature and are guaranteed by us and our material subsidiaries. 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.

In the event that we do not comply with the covenants contained in the Credit Facilities, our ability to pay dividends to Shareholders may be restricted. We are restricted from paying dividends when (i) a default or event of default under the Credit Facilities has occurred and is continuing, or (ii) the payment of such dividends would be reasonably expected to have a material adverse effect on us or impair our ability to fulfill our financial obligations to the lenders under the Credit Facilities. See "*Risk Factors — Risks Related to our Business and Operations — Failure to renew our Credit Facilities or failure to comply with the covenants in the agreements governing our debt could adversely affect our financial condition*" and "*Dividends — Dividend Policy*".

## DIVIDENDS

### Dividend Policy

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. 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, 2014, our legal stated capital was approximately $3.6 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 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 indentures governing our Senior Notes also contain 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. As at the date of this Annual Information Form, we are in compliance with these covenants. The following is a summary of certain of these covenants and is not intended to be complete. For full particulars of the covenants, reference should be made to the indentures governing our Senior Notes. See "*Material Contracts*".

Under Debt Indenture #1, 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 Debt Indenture #1 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 Debt Indenture #1; (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 after August 26, 2009 pursuant to this paragraph (ii) does not exceed the sum of restricted payments that were permitted to be made under paragraph (i) but were not actually made (and have not previously been expended under this paragraph (ii)), plus $50,000,000.

Under Debt Indenture #2, 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: (a) no default or event of default under Debt Indenture #2 has occurred and is continuing, (b) solely in respect of the use of amounts available under (c)(A) below, we could incur at least US$1.00 of additional indebtedness (other than certain permitted debt) in accordance with the "Incurrence of Indebtedness" covenant in Debt Indenture #2; and (c) the aggregate amount of all restricted payments declared or made after April 1, 2014 (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 April 1, 2014, plus (B) 100% of the aggregate net cash proceeds received by us after June 11, 2014 as a contribution to our common equity capital or from the issue or sale of equity interests; plus (C) the amount by which indebtedness is reduced upon the conversion or exchange of any indebtedness that is convertible or exchangeable for common equity capital subsequent to June 11, 2014, plus (D) an amount equal to the sum of (x) the net reduction in investments made by us in any person resulting from repurchases, repayments or redemptions of such investments by such person, proceeds realized on the sale of such investments and proceeds representing a return of capital, and (y) to the extent that such person is an unrestricted subsidiary, the portion of the fair market value of the net assets of such unrestricted subsidiary at the time it is designated a restricted subsidiary, plus (E) US$625 million; provided that if at the time of such restricted payment and after giving pro forma effect thereto as if such restricted payment had been made at the beginning of the applicable four-quarter period, we would not have been permitted to incur at least US$1.00 of additional indebtedness (other than certain permitted debt) in accordance with the "Incurrence of Indebtedness" covenant in the Debt Indenture #2, such sum less amounts previously paid pursuant to the foregoing clauses (A)-(D) shall be limited to US$500 million plus the amount referred to under (B) above to the extent not previously expended.

**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 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. See "*Dividends — Dividend Policy*". The following table sets forth the dividends that we have paid on our Common Shares.

| Month | Dividends per Common Share ($) 2015 | 2014 | 2013 | 2012 | 2011 |
|---|---|---|---|---|---|
| January | 0.10 | 0.22 | 0.22 | 0.22 | 0.20 |
| February | 0.10 | 0.22 | 0.22 | 0.22 | 0.20 |
| March | | 0.22 | 0.22 | 0.22 | 0.20 |
| April | | 0.22 | 0.22 | 0.22 | 0.20 |
| May | | 0.22 | 0.22 | 0.22 | 0.20 |
| June | | 0.24 | 0.22 | 0.22 | 0.20 |
| July | | 0.24 | 0.22 | 0.22 | 0.20 |
| August | | 0.24 | 0.22 | 0.22 | 0.20 |
| September | | 0.24 | 0.22 | 0.22 | 0.20 |
| October | | 0.24 | 0.22 | 0.22 | 0.20 |
| November | | 0.24 | 0.22 | 0.22 | 0.20 |
| December | | 0.10 | 0.22 | 0.22 | 0.20 |
| **Total** | | $ 2.64 | $ 2.64 | $ 2.64 | $ 2.40 |

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.

| Month | Distributions per Trust Unit ($) 2010 | 2009 | 2008 | 2007 | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|---|---|
| January | 0.18 | 0.18 | 0.18 | 0.18 | 0.15 | 0.15 | 0.15 | — |
| February | 0.18 | 0.18 | 0.18 | 0.18 | 0.18 | 0.15 | 0.15 | — |
| March | 0.18 | 0.12 | 0.18 | 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 | 0.20 | 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 | — |
| 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 | 0.18 | 0.12 | 0.25 | 0.18 | 0.18 | 0.15 | 0.15 | 0.15 |
| **Total** | $ 2.16 | $ 1.56 | $ 2.64 | $ 2.16 | $ 2.13 | $ 1.80 | $ 1.80 | $ 0.45 |

### Dividend Reinvestment Plan

Baytex has a Dividend Reinvestment Plan (the "**DRIP**") that provides a convenient and cost-effective method for eligible holders in Canada 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[1] | 58.77 | 39.18 | 158,199,516 | 61.96 | 36.89 | 79,445,292 |
| 2012 | 59.40 | 38.54 | 153,598,017 | 59.50 | 37.40 | 56,366,309 |
| 2013 | 47.61 | 36.37 | 154,850,873 | 47.47 | 34.71 | 43,934,391 |
| 2014 | 49.88 | 14.56 | 273,743,069 | 46.46 | 12.62 | 107,631,897 |
| | | | | | | |
| 2014 | | | | | | |
| January | 42.49 | 39.18 | 9,447,871 | 39.42 | 35.51 | 4,269,728 |
| February | 41.77 | 38.90 | 27,012,448 | 37.81 | 35.30 | 5,612,392 |
| March | 45.65 | 40.43 | 17,320,322 | 41.32 | 36.48 | 3,495,175 |
| April | 46.72 | 44.67 | 13,249,918 | 42.39 | 40.69 | 3,356,366 |
| May | 46.72 | 44.30 | 15,654,966 | 42.96 | 40.72 | 2,728,728 |
| June | 49.88 | 45.41 | 17,047,093 | 46.30 | 41.69 | 3,976,673 |
| July | 49.49 | 45.81 | 10,827,626 | 46.46 | 42.56 | 3,430,220 |
| August | 48.70 | 44.33 | 14,155,287 | 44.79 | 40.56 | 5,862,358 |
| September | 48.49 | 41.73 | 15,662,178 | 44.59 | 37.54 | 8,216,443 |
| October | 42.90 | 32.87 | 32,968,019 | 38.35 | 29.03 | 15,325,187 |
| November | 34.54 | 23.10 | 36,160,224 | 30.61 | 21.63 | 16,838,774 |
| December | 23.82 | 14.56 | 64,237,117 | 20.96 | 12.62 | 34,519,853 |
| | | | | | | |
| 2015 | | | | | | |
| January | 20.38 | 16.03 | 34,069,306 | 17.14 | 13.41 | 18,344,670 |
| February | 24.87 | 20.13 | 30,889,002 | 19.19 | 16.06 | 19,098,664 |

Note:

(1) The trading data for Canada Composite Trading is for the period from January 7 to December 31, 2011. The trading data for United States Composite Trading is for the period from January 3 to December 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 and the associated costs to (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 with a stable outlook and our Senior Notes 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 Ba3 with a stable outlook and our Senior Notes have been assigned a credit rating of Ba3 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 "Ba" are considered to have speculative elements and are subject to substantial 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. In addition, Moody's may add a rating outlook of "positive", "negative", "stable" or "developing" which assess the likely direction of an issuers rating over the medium term.

**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.**

We have made payments to S&P and Moody's in connection with the assignment of ratings to our long-term debt and may make payments to S&P and Moody's in the future in connection with the confirmation of such ratings for purposes of the offering of debt securities.

## 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 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 in Canada, the 2021 Debentures and the 2022 Debentures. First American Stock Transfer, Inc., at its principal office in Phoenix, Arizona, is the transfer agent and registrar for the Common Shares in the United States. Computershare Trust Company, N.A., at its principal office in Canton, Massachusetts, is the transfer agent and registrar for the 2021 Notes and the 2024 Notes. U.S. National Bank Association, at its principal office in Houston, Texas, is the transfer agent and registrar for the 2020 Aurora Notes.

## 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, Ryder Scott and McDaniel, our independent qualified reserves evaluators. None of the designated professionals of Sproule, Ryder Scott or McDaniel 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 June 11, 2014) and amendments thereto (filed on SEDAR on September 9, 2014 and February 24, 2015);

(b) Debt Indenture #1 (filed on SEDAR on January 10, 2011) and supplemental indentures thereto (filed on SEDAR on February 22, 2011, July 19, 2012, January 14, 2013, August 13, 2014, September 9, 2014 and March 9, 2015);

(c) Debt Indenture #2 (filed on SEDAR on June 20, 2014) and supplemental indentures thereto (filed on SEDAR on August 13, 2014 and September 9, 2014); and

(d) our share award incentive plan (filed on SEDAR on March 14, 2013).

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 controls and regulation in respect 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. The oil and gas industry is also subject to agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas with respect to pricing and taxation of oil and natural gas. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada and the United States.

### Pricing and Marketing

#### *Oil*

In Canada and the United States, producers of oil are entitled to negotiate sales contracts directly with oil purchasers. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional markets and transportation issues. The specific price depends in part on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, the supply/demand balance and contractual terms of sale.

Oil can be exported from Canada provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**") and the term of the export contract does not exceed one year in the case of light crude oil and two years in the case of heavy crude oil. Any Canadian 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. Oil exports from the United States are controlled by the United States Department of Commerce ("**DOC**") and only in limited circumstances will the DOC approve applications to export crude oil. Recently, the Bureau of Industry and Security (an agency within the DOC) issued written guidance indicating that processed condensate could be exported without a license, allowing for some exports which were recently thought to require a license.

#### *Natural Gas*

In Canada and the United States producers of gas are entitled to negotiate sales contracts directly with gas purchasers. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system, at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms.

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 export licence from the NEB.

Natural gas exported from the United States is regulated principally by the Federal Energy Regulatory Commission ("**FERC**") and the United States Department of Energy ("**DOE**"). U.S. law provides for very limited regulation of exports to and imports from any country that has entered into a free trade agreement with the United States that provides for national treatment of trade in natural gas; however, the DOE regulation of imports and exports from and to countries without such free trade agreements is more comprehensive.

The FERC regulates rates and service conditions for the transportation of natural gas in interstate commerce. The prices and terms of access to intrastate pipeline transportation are subject to state regulation. In Texas, the primary regulator is the Texas Railroad Commission. Facilities used in the production or gathering of natural gas in interstate commerce are generally exempt from FERC jurisdiction. However, the distinction between FERC-regulated transmission pipelines and unregulated gathering systems is made by the FERC on a case-by-case basis and has been subject to extensive litigation.

**The North American Free Trade Agreement**

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force 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**

In addition to federal regulation, each province in Canada and each state in the United States has legislation and regulations that govern royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of hydrocarbon production. Royalties payable on production from lands other than Crown lands in Canada and federal and state lands in the United States are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain taxes and royalties. Royalties from production on Crown lands in Canada and federal and state lands in the United States 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.

From time to time the federal and provincial governments in Canada and the federal and state governments in the United States create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and are generally introduced to encourage specific types of exploration and development activity.

**Land Tenure**

In western Canada the rights to crude oil and natural gas is predominantly owned by the provincial government. 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. In the United States, private ownership of the rights to crude oil and natural gas is predominant. Where mineral rights are privately owned, the rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated. Private ownership of oil and natural gas also exists in western Canada. Government and private leases are generally granted for an initial fixed term but may generally be continued provided certain minimum levels of drilling operations or production have been achieved and all lease rentals have been timely paid, subject to certain exceptions.

To develop minerals, including oil and gas, it is necessary for the mineral estate owner(s) to have access to the surface estate. Under common law in Canada and the United States, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each province and state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling, including notification requirements and the provision of compensation for lost land use and surface damages. The surface rights required for pipelines and facilities are generally governed by leases, easements, rights-of-way, permits or licenses granted by landowners or governmental authorities.

**Liability Management Rating Programs**

Each of Alberta and Saskatchewan have implemented similar liability management programs in respect of most conventional upstream oil and gas wells, facilities and pipelines. These programs require a licensee whose deemed liabilities exceed its deemed assets within the jurisdiction to provide a security deposit. In Texas, each operator of a well must file a bond, letter of credit, or cash deposit with the Texas Railroad Commission. The amount of the bond, letter of credit or deposit varies by number and type of wells, but is not dependent upon the financial capacity of the operator.

**Environmental and Occupational Safety and Health Regulation**

The oil and natural gas industry is currently subject to stringent environmental, health and safety regulation pursuant to a variety of municipal, provincial, state and federal controls, laws, and regulations governing occupational health and safety aspects of our operations, the spill, release or emission of materials into the environment, or otherwise relating to environmental protection, all of which is subject to governmental review and revision from time to time. Such controls, laws and regulations, among other things, require the acquisition of permits or other approvals to conduct drilling and other regulated activities; restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and natural gas drilling and production activities; limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; impose specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from drilling and production operations. In addition, controls, laws and regulations sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such controls, laws and regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, remedial obligations, civil liability and the imposition of material administrative, civil and criminal penalties.

Environmental legislation in the Province of Alberta is, for the most part, set out in the *Environmental Protection and Enhancement Act* and the *Oil and Gas Conservation Act*, which impose strict environmental standards with respect to releases of effluents and emissions, including monitoring and reporting obligations, and impose significant penalties for non-compliance. For example, regulations enacted thereunder target sulphur dioxide and nitrous oxide emissions from oil and gas operations. Environmental legislation in the Province of Saskatchewan is, for the most part, set out in the *Environmental Management and Protection Act*, *2002* and the *Oil and Gas Conservation Act*, which regulate harmful or potentially harmful activities and substances, any release of such substances, and remediation obligations. Certain development activities in Saskatchewan, depending on the location and potential environmental impact, may require a screening or an environmental impact assessment under the provincial *Environmental Assessment Act*.

In the United States, environmental conservation, cultural and natural resources protection at the federal level are administered by numerous agencies under multiple statutes. The more significant of these existing environmental and occupational health and safety laws and regulations include the following U.S. laws and regulations, as amended from time to time:

- the U.S. Clean Air Act, which restricts the emission of air pollutants from many sources and imposes various pre-construction, monitoring, and reporting requirements;
- the U.S. Federal Water Pollution Control Act, also known as the federal Clean Water Act ("**CWA**"), which regulates discharges of pollutants from facilities to state and federal waters;
- the U.S. Oil Pollution Act of 1990 ("**OPA**"), which subjects owners and operators of vessels, onshore facilities, and pipelines, as well as lessees or permittees of areas in which offshore facilities are located, to liability for removal costs and damages arising from an oil spill in waters of the United States;
- the Comprehensive Environmental Response, Compensation and Liability Act of 1980, which imposes liability on generators, transporters, and arrangers of hazardous substances at sites where hazardous substance releases have occurred or are threatening to occur;
- the U.S. Resource Conservation and Recovery Act, which governs the generation, treatment, storage, transport, and disposal of solid wastes, including hazardous wastes;
- the U.S. Safe Drinking Water Act, which ensures the quality of the nation's public drinking water through adoption of drinking water standards and controlling the injection of waste fluids into below-ground formations that may adversely affect drinking water sources;
- the U.S. Emergency Planning and Community Right-to-Know Act, which requires facilities to implement a safety hazard communication program and disseminate information to employees, local emergency planning committees, and response departments on toxic chemical uses and inventories;
- the U.S. Occupational Safety and Health Act, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- the U.S. Endangered Species Act, which restricts activities that may affect federally identified endangered and threatened species or their habitats through the implementation of operating restrictions or a temporary, seasonal, or permanent ban in affected areas; and
- the U.S. National Environmental Protection Act, which requires federal agencies, including the federal Bureau of Land Management, to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment.

These laws and regulations, as well as state counterparts, generally restrict the level of pollutants emitted to ambient air, discharges to surface water, and disposals or other releases to surface and below-ground soils and ground water. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil, and criminal penalties; the imposition of investigatory, remedial, and corrective action obligations or the incurrence of capital expenditures; the occurrence of delays in the development of projects; and the issuance of injunctions restricting or prohibiting some or all of the Company's activities in a particular area.

In 2011, the EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, and to identify the driving factors that may affect the severity and frequency of such impacts. The regulation surrounding hydraulic fracturing in Texas falls within two basic categories: (i) design and operational requirements; and (ii) information disclosure. Texas requires operators to disclose information about the chemicals used in their completions. Baytex USA complies with this requirement for the wells it operates by posting the necessary information on the internet-based chemical registry FracFocus. FracFocus is operated by the Ground Water Protection Council, a group of state water officials, and the Interstate Oil and Gas Compact Commission, an association of oil and gas producing states. The online registry was created in 2011, in response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the petroleum industry, and Baytex USA has determined to utilize the registry in all states in which it operates.

In 2012, the EPA issued final rules that established new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The final rule includes a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or re-fractured after January 1, 2015. The rules also establish specific requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment.

In December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015, which proposes to revise the National Ambient Air Quality Standard for ozone between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards. The current primary and secondary ozone standards are set at 75 ppb. EPA also requested public comments on whether the standard should be set as low as 60 ppb or whether the existing 75 ppb standard should be retained. If EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could apply to our operations.

In January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025.

**Climate Change Regulation**

Both Canada and the United States are signatories to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and are participants in the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). Both governments agreed to an economy-wide target of a 17% reduction of GHG emissions from 2005 levels.

The Government of Canada has proposed emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Representatives of the Government of Canada have indicated that its proposals will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. At present, the proposed regulations from the Government of Canada applicable to the oil and gas industry remain pending.

The Province of Alberta has implemented legislation to promote emission reduction targets for facilities emitting more than 100,000 tonnes of GHGs. The Province of Saskatchewan has set forth similar legislation that is not yet in force for facilities that emit more than 50,000 tonnes of GHGs. At present, we do not operate any facilities in Alberta or Saskatchewan that exceed these thresholds.

The EPA announced on December 7, 2009 its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of greenhouse gases under existing provisions of the federal *Clean Air Act*. One such regulation that has been issued by the EPA is the Mandatory Reporting of Greenhouse Gases Rule pursuant to which, petroleum and natural gas systems sources above a certain threshold at an onshore basin level are required to submit an annual greenhouse gas emissions report. Baytex USA is subject to this regulation and its reporting requirements.

**General**

Implementation of more stringent environmental regulations on our operations could affect the capital and operating expenditures and plans for our operations. In addition to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, state water quality, fish, wildlife, visual quality, transportation, noise, spills, incidents and transportation.

We believe that, in all material respects, we are in compliance with, and have complied with, all applicable environmental laws and regulations. We have made and will continue to make expenditures in our efforts to comply with all environmental regulations and requirements. We consider these a normal, recurring cost of our ongoing operations and not an extraordinary cost of compliance with governmental regulations. We believe that our continued compliance with existing requirements has been accounted for and will not have a material and adverse impact on our financial condition, results of operations and operating cash flows. However, we cannot predict the passage of or quantify the potential impact of any more stringent future laws and regulations at this time.

## ADDITIONAL INFORMATION

Additional information relating to us can be found on the SEDAR website at *www.sedar.com* and on our website at *www.baytexenergy.com.* 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 12, 2015. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2014 and the related management's discussion and analysis which are accessible on the SEDAR website at *www.sedar.com*. For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

Baytex Energy Corp.
Suite 2800, Centennial Place, East Tower
520 - 3rd Avenue S.W.
Calgary, Alberta T2P 0R3
Phone: (587) 952-3000
Fax: (587) 952-3029
Website: *www.baytexenergy.com*

# 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, 2014, 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) "*James L. Bowzer*"
James L. Bowzer
President and Chief Executive Officer

(signed) "*Rodney D. Gray*"
Rodney D. Gray
Chief Financial Officer

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

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

March 9, 2015

## 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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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, 2014, 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 — $ thousands) | | | |
|---|---|---|---|---|---|---|
| | | | Audited | Evaluated | Reviewed | Total |
| Sproule Unconventional Limited | Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2014). Prepared: September 2014 to February 2015 | Canada | Nil | $ 3,275,340 | Nil | $ 3,275,340 |

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

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 February 17, 2015.

**Sproule Unconventional Limited**

(signed) "*Cameron P. Six*"

Cameron P. Six, P.Eng.
Vice-President, Unconventional and Director

(signed) "*Alec Kovaltchouk*"

Alec Kovaltchouk, P.Geol
Manager, Geoscience and Partner

(signed) "*Steven J. Golko*"

Steven J. Golko, P.Eng.
Partner

(signed) "*Matthew J. Tymchuk*"

Matthew J. Tymchuk, P.Eng.
Petroleum Engineer and Partner

**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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, 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, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the management and Board of Directors of Baytex:

| | | | Net Present Value of Future Net Revenue Before income taxes (10% discount rate — $ thousands) | | | |
|---|---|---|---|---|---|---|
| **Independent Qualified Reserves Evaluator or Auditor** | **Description and Preparation Date of Evaluation Report** | **Location of Reserves** | **Audited** | **Evaluated** | **Reviewed** | **Total** |
| Ryder Scott Company, L.P. | Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2014). Preparation Date: January 31, 2015 | United States | Nil | $ 2,383,429 | Nil | $ 2,383,429 |

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

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 January 31, 2015.

**Ryder Scott Company, L.P.**
Texas Registered Engineering Firm F-1580
Houston, Texas, USA

(signed) "*Ryder Scott Company, L.P.*"

**APPENDIX C**

**BAYTEX ENERGY CORP.**

**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:

1. assist directors in meeting their responsibilities in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. facilitate communication between directors and the external auditors;

3. enhance the external auditors' independence;

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

5. 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*

**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, James L. Bowzer, 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/ JAMES L. BOWZER

Name: James L. Bowzer
Title: President and Chief Executive Officer

Dated: March 9, 2015

**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, Rodney D. Gray, 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/ RODNEY D. GRAY

Name: Rodney D. Gray
Title: Chief Financial Officer

Dated: March 9, 2015

**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, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, James L. Bowzer, 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/ JAMES L. BOWZER

Name: James L. Bowzer
Title: President and Chief Executive Officer

Dated: March 9, 2015

**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, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Rodney D. Gray, 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/ RODNEY D. GRAY

Name: Rodney D. Gray
Title: Chief Financial Officer

Dated: March 9, 2015

**Exhibit 99.8**

## CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements Nos. 333-163289 and 333-171568 on Form S-8; and Registration Statement No. 333-171866 on Form F-3 of Baytex Energy Corp. and its subsidiaries ("Baytex"); and Registration Statements Nos. 333-191762 and 333-191764 on Form F-10 and F-3 of Baytex and Baytex Energy USA Ltd.; and to the use of our reports dated March 4, 2015 relating to the consolidated financial statements of Baytex and the effectiveness of Baytex's internal control over financial reporting appearing in this Form 40-F of Baytex for the year ended December 31, 2014.

/s/ DELOITTE LLP
Chartered Accountants
March 9, 2015
Calgary, Canada

**Exhibit 99.9**

**CONSENT OF INDEPENDENT ENGINEERS**

We refer to: (i) our report dated February 17, 2015 and effective December 31, 2014, evaluating the proved and probable petroleum and natural gas reserves attributable to Baytex Energy Corp. (the "Company") and its affiliates, which is entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. in Canada (As of December 31, 2014)*"; (ii) our report dated February 27, 2015 and effective December 31, 2014, evaluating the proved and probable petroleum and natural gas reserves attributable the Company and its affiliates, which is entitled "*Consolidation of the P&NG Reserves of Baytex Energy Corp. Evaluated by Sproule Unconventional Limited and Ryder Scott Company L.P. (As of December 31, 2014*)"; (iii) our assessment dated March 4, 2015 and effective December 31, 2014, evaluating the contingent resources attributable to the Company in the Seal Area of Alberta, which is entitled "*Update to the Evaluation of the Contingent Bitumen Resources of Baytex Energy Corp. in the Peace River Area of Alberta (As of December 31, 2014)*"; and (iv) our assessment dated March 4, 2015 and effective December 31, 2014, evaluating the contingent resources attributable to the Company in the Cold Lake Area of Alberta, which is entitled "*Update to the Evaluation of the Contingent Bitumen Resources of Baytex Energy Corp. for the Gemini SAGD Project in the Cold Lake Area of Alberta (As of December 31, 2014)*" (collectively, the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and 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 333-191762 on Form F-10 of the Company and Registration Statement No. 333-191764 on Form F-3 of Baytex Energy USA Ltd. and to the use of the Report.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2014 dated March 9, 2015, 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 UNCONVENTIONAL LIMITED**

/s/ STEVEN J. GOLKO

Steven J. Golko, P. Eng.
Supervisor, Engineering and Partner

Calgary, Alberta, Canada
March 9, 2015

**Exhibit 99.10**

**CONSENT OF INDEPENDENT ENGINEERS**

We refer to: (i) our report dated January 31, 2015 and effective December 31, 2014, evaluating the proved and probable petroleum and natural gas reserves attributable to Baytex Energy Corp. (the "Company") and its affiliates located in the United States, which is entitled "*Baytex Energy Corp. Summary Report Estimated Future Reserves and Income Attributable to Certain Leasehold Interests NI 51-101 Forecast Economic Parameters Canadian Currency As of December 31, 2014*"; and (ii) our letter report dated February 6, 2015 and effective December 31, 2014, auditing the possible petroleum and natural gas reserves attributable the Company and its affiliates in the Eagle Ford area of Texas (collectively, the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and 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 333-191762 on Form F-10 of the Company and Registration Statement No. 333-191764 on Form F-3 of Baytex Energy USA Ltd. and to the use of the Report.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2014 dated March 9, 2015, 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.

/s/ RYDER SCOTT COMPANY, L.P.

**RYDER SCOTT COMPANY, L.P.**
TBPE Firm Registration No. F-1580
Houston, Texas, United States of America
March 9, 2015

**Exhibit 99.11**

**CONSENT OF INDEPENDENT ENGINEERS**

We refer to our assessment dated February 26, 2015 and effective December 31, 2014, evaluating the contingent resources attributable to Baytex Energy Corp. (the "Company") and its affiliates in the Lower Cretaceous Mannville Group in northeast Alberta, which is entitled "*Evaluation of Contingent Resources*" (the "Report").

We hereby consent to the references to our name in the Company's Annual Report on Form 40-F to be filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, and 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 333-191762 on Form F-10 of the Company and Registration Statement No. 333-191764 on Form F-3 of Baytex Energy USA Ltd. and to the use of the Report.

We also confirm that we have read the Company's Annual Information Form for the year ended December 31, 2014 dated March 9, 2015, 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.

**McDANIEL & ASSOCIATES CONSULTANTS LTD.**

/s/ P.A. WELCH

P.A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta, Canada
March 9, 2015

**Exhibit 99.12**

**Baytex Energy Corp.**
**Supplemental Disclosures about Extractive Activities — Oil and Gas (unaudited)**
**December 31, 2014**

The following disclosures have been prepared by Baytex Energy Corp. ("Baytex" or the "Company") in accordance with Accounting Standards Codification 932 "Extractive Activities — Oil & Gas" ("ASC 932") issued by the Financial Accounting Standards Board.

**Petroleum and Natural Gas Reserve Information**

Proved petroleum and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids ("NGL") that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved developed petroleum and natural gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods, which may require future expenditures.

Proved undeveloped petroleum and natural gas reserves are reserves that are expected to be recovered from known accumulations where a future expenditure is required.

Reserves are estimated quantities of crude oil, NGL and natural gas anticipated from geological and engineering data to be recoverable from known accumulations, from a given date forward, by known technology, under existing operating conditions and considered to be economic at average commodity prices based upon the prior 12-month period. Estimates of petroleum and natural gas reserves are subject to uncertainty and will change as additional information regarding the producing fields and technology becomes available and as future economic conditions change. Net reserves presented in this section represent the Company's working interest and overriding royalty share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

The changes in Baytex's net proved crude oil and NGL and natural gas reserves under constant prices and costs for the two-year period ended December 31, 2014 were as follows:

| | Canada | | | United States | | | Total | | |
|---|---|---|---|---|---|---|---|---|---|
| | Crude Oil & NGL (mbbl) | Bitumen (mbbl) | Natural Gas (mmcf) | Crude Oil & NGL (mbbl) | Bitumen (mbbl) | Natural Gas (mmcf) | Crude Oil & NGL (mbbl) | Bitumen (mbbl) | Natural Gas (mmcf) |
| **Net proved reserves** | | | | | | | | | |
| December 31, 2012 | 74,328 | 17,067 | 48,711 | 15,951 | — | 8,597 | 90,279 | 17,067 | 57,308 |
| Revisions of previous estimates | (342) | 1,142 | 7,314 | 8,263 | — | 23,512 | 7,921 | 1,142 | 30,826 |
| Improved recovery | 209 | — | — | — | — | — | 209 | — | — |
| Purchases | — | — | — | — | — | — | — | — | — |
| Extensions and discoveries | 10,566 | — | 2,825 | 659 | — | 751 | 11,225 | — | 3,576 |
| Production | (12,632) | (846) | (13,020) | (771) | — | (80) | (13,403) | (846) | (13,100) |
| Sales of minerals in place | (1,086) | — | — | — | — | — | (1,086) | — | — |
| December 31, 2013 | 71,043 | 17,363 | 45,830 | 24,102 | — | 32,780 | 95,145 | 17,363 | 78,610 |
| Revisions of previous estimates | 646 | (1,317) | 31,865 | — | — | — | 646 | (1,317) | 31,865 |
| Improved recovery | 33 | — | 2 | — | — | — | 33 | — | 2 |
| Purchases | 3,282 | — | — | 99,848 | — | 179,376 | 103,130 | — | 179,376 |
| Extensions and discoveries | 6,795 | — | 11,428 | — | — | — | 6,795 | — | 11,428 |
| Production | (12,442) | (1,051) | (12,993) | (4,959) | — | (5,972) | (17,401) | (1,051) | (18,965) |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Sales of minerals in place | (3,648) | — | (6,770) | (24,122) | — | (32,845) | (27,770) | — | (39,615) |
| December 31, 2014 | 65,709 | 14,995 | 69,362 | 94,869 | — | 173,339 | 160,578 | 14,995 | 242,701 |
| **Net proved developed reserves** | | | | | | | | | |
| End of year 2012 | 43,394 | 4,623 | 35,875 | 4,021 | — | 1,951 | 47,415 | 4,623 | 37,826 |
| End of year 2013 | 43,161 | 9,929 | 35,017 | 4,325 | — | 5,091 | 47,486 | 9,929 | 40,108 |
| End of year 2014 | 40,931 | 8,157 | 48,321 | 32,227 | — | 50,768 | 73,158 | 8,157 | 99,089 |
| **Net proved undeveloped reserves** | | | | | | | | | |
| End of year 2012 | 30,934 | 12,444 | 12,836 | 11,930 | — | 6,646 | 42,864 | 12,444 | 19,482 |
| End of year 2013 | 27,882 | 7,434 | 10,813 | 19,777 | — | 27,689 | 47,659 | 7,434 | (9,282) |
| End of year 2014 | 24,778 | 6,838 | 21,041 | 62,642 | — | 122,571 | 87,420 | 6,838 | 143,612 |

The most significant changes to proved reserves estimates (and related changes to standardized measure of future net cash flows described below) occurring between December 31, 2012 and December 31, 2013 related primarily to the addition to previous proved reserves estimates of reserves in the Bakken/Three Forks area in North Dakota. The most significant changes to proved reserves estimates (and related changes to standardized measure of future net cash flows described below) occurring between December 31, 2013 and December 31, 2014 related to the purchase of proved reserves in the Eagle Ford shale in South Texas attributable to the Company's acquisition of Aurora Oil & Gas Limited in June 2014 and the sale of proved reserves as a result of the Company's disposition of its Bakken/Three Forks properties in North Dakota in September 2014.

**Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Petroleum and Natural Gas Reserves**

The following information has been developed utilizing procedures prescribed by ASC 932, as updated by Accounting Standards Update 2010-03 "Oil and Gas Reserve Estimation and Disclosures", and based on crude oil, NGL and natural gas reserve and production volumes estimated by Baytex's independent reserves evaluator, Sproule Associates Limited. The methodology used in calculating our price and cost assumptions for the standardized measure of discounted future net cash flows for reserve estimation is based upon the average first-day-of-the-month prices during the year.

Future production and development costs are based on forecast price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the petroleum and natural gas properties based upon existing laws and regulations. A 10% discount factor was applied to the future net cash flows.

The information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the fair market value of Baytex's petroleum and natural gas properties. Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated. The prescribed discount rate of 10% may not appropriately reflect interest rates.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves was based on an unweighted arithmetic average of the first-day-of-the-month price for each month in 2014 and 2013.

| | Commodity Pricing | |
|---|---|---|
| | **2014** | **2013** |
| WTI crude (US$/bbl) | $ 94.99 | $ 96.94 |
| Edmonton par (Cdn$/bbl) | $ 94.84 | $ 92.73 |
| Heavy oil[1] (Cdn$/bbl) | $ 82.96 | $ 74.22 |
| AECO-C spot price (Cdn$/mmbtu) | $ 4.60 | $ 3.16 |
| Henry Hub (US$/mmbtu) | $ 4.30 | $ 3.68 |
| Exchange rate (US$/Cdn$) | 0.9100 | 0.9717 |

(1) Heavy oil pricing refers to Western Canadian Select reference price.

The standardized measure of discounted future net cash flows relating to net proved oil, NGL and natural gas reserves are as follows:

| (thousands of Canadian dollars) | Canada 2014 | Canada 2013 | United States 2014 | United States 2013 | Total 2014 | Total 2013 |
|---|---|---|---|---|---|---|
| Future cash inflows | $ 5,927,985 | $ 5,908,063 | $ 8,246,158 | $ 2,262,625 | $ 14,174,143 | $ 8,170,688 |
| Future production costs | (2,013,766) | (2,446,053) | (2,082,635) | (500,460) | (4,096,401) | (2,946,513) |
| Future development costs | (659,398) | (647,433) | (1,678,370) | (619,088) | (2,337,768) | (1,266,521) |
| Future income taxes | (467,661) | (372,089) | (670,916) | (444,121) | (1,138,577) | (816,210) |
| Future net cash flows | 2,787,160 | 2,442,488 | 3,814,237 | 698,956 | 6,601,397 | 3,141,444 |
| Deduct: | | | | | | |
| 10% annual discount factor | (869,342) | (742,421) | (1,618,886) | (395,433) | (2,488,228) | (1,137,854) |
| Standardized measure | $ 1,917,818 | $ 1,700,067 | $ 2,195,351 | $ 303,523 | $ 4,113,169 | $ 2,003,590 |

**Reconciliation of Changes in Standardized Measure of Future Net Cash Flows Discounted at 10% per Year Relating to Proved Petroleum and Natural Gas Reserves**

**As at December 31, 2014**

| (thousands of Canadian dollars) | Canada | United States | Total |
|---|---|---|---|
| Balance, beginning of year | $ 1,700,067 | $ 303,523 | $ 2,003,590 |
| Sales, net of production costs | (787,203) | (331,794) | (1,118,997) |
| Net change in prices and production costs related to future production | (510,709) | — | (510,709) |
| Changes in previously estimated production costs incurred during the period | 2,359 | (899,225) | (896,866) |
| Development costs incurred during the period | 388,406 | 384,465 | 772,871 |
| Extensions, discoveries and improved recovery, net of related costs | 175,968 | — | 175,968 |
| Revisions of previous quantity estimates | 788,598 | — | 788,598 |
| Sales of reserves in place | (30,069) | (537,424) | (567,493) |
| Purchases of reserves in place | 78,732 | 3,362,185 | 3,440,917 |
| Accretion of discount | 152,375 | 47,274 | 199,649 |
| Net change in income taxes | (40,707) | (133,653) | (174,360) |
| Balance, end of year | $ 1,917,817 | $ 2,195,351 | $ 4,113,168 |

**As at December 31, 2013**

| (thousands of Canadian dollars) | Canada | United States | Total |
|---|---|---|---|
| Balance, beginning of year | $ 1,727,560 | $ 113,445 | $ 1,841,005 |
| Sales, net of production costs | (716,841) | (44,581) | (761,422) |
| Net change in prices and production costs related to future production | 16,617 | 16,974 | 33,591 |
| Changes in previously estimated production costs incurred during the period | 80,168 | (224,833) | (144,665) |
| Development costs incurred during the period | 467,191 | 75,176 | 542,367 |
| Extensions, discoveries and improved recovery, net of related costs | 248,269 | 218,266 | 466,535 |
| Revisions of previous quantity estimates | (284,204) | 244,884 | (39,320) |
| Sales of reserves in place | (7,498) | — | (7,498) |
| Purchases of reserves in place | — | — | — |
| Accretion of discount | 160,493 | 18,380 | 178,873 |
| Net change in income taxes | 8,312 | (114,188) | (105,876) |
| Balance, end of year | $ 1,700,067 | $ 303,523 | $ 2,003,590 |

### Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

| As at December 31, 2014 (thousands of Canadian dollars) | Canada | United States | Total |
|---|---|---|---|
| Proved properties | $ 3,392,578 | $ 3,039,182 | $ 6,431,760 |
| Unproved properties | 124,494 | 417,546 | 542,040 |
| Total capital costs | 3,517,072 | 3,456,728 | 6,973,800 |
| Accumulated depletion and depreciation | (1,258,258) | (189,586) | (1,447,844) |
| Net capitalized costs | $ 2,258,814 | $ 3,267,142 | $ 5,525,956 |

| As at December 31, 2013 (thousands of Canadian dollars) | Canada | United States | Total |
|---|---|---|---|
| Proved properties | $ 3,047,557 | $ 290,761 | $ 3,338,318 |
| Unproved properties | 127,736 | 35,556 | 163,292 |
| Total capital costs | 3,175,293 | 326,317 | 3,501,610 |
| Accumulated depletion and depreciation | (999,832) | (38,207) | (1,038,039) |
| Net capitalized costs | $ 2,175,461 | $ 288,110 | $ 2,463,571 |

### Costs Incurred in Petroleum and Natural Gas Property Acquisition, Exploration and Development Activities

| For year ended December 31, 2014 (thousands of Canadian dollars) | Canada | United States | Total |
|---|---|---|---|
| Property acquisition costs(1) | | | |
| Proved properties | $ 1,005 | $ 2,524,018 | $ 2,525,023 |
| Unproved properties | 10,948 | 392,315 | 403,263 |
| Property dispositions(2) | (45,816) | (337,314) | (383,130) |
| Development costs(3) | 388,405 | 370,543 | 758,948 |
| Exploration costs(4) | 5,823 | 1,299 | 7,122 |
| Total | $ 360,365 | $ 2,950,861 | $ 3,311,226 |

| For year ended December 31, 2013 (thousands of Canadian dollars) | Canada | United States | Total |
|---|---|---|---|
| Property acquisition costs | | | |
| Proved properties | $ 3,604 | $ 90 | $ 3,694 |
| Unproved properties | 707 | 2,353 | 3,060 |
| Property dispositions | (45,003) | (833) | (45,836) |
| Development costs(3) | 467,191 | 75,176 | 542,367 |
| Exploration costs(4) | 7,110 | 1,423 | 8,533 |
| Total | $ 433,609 | $ 78,209 | $ 511,818 |

(1) Property acquisition costs include the acquisition of Aurora Oil & Gas Limited.
(2) Property dispositions include the disposition of assets in North Dakota and in Canada.
(3) Development and facilities capital expenditures.
(4) Cost of geological and geophysical capital expenditures and drilling costs for exploratory wells.

**Results of Operations for Producing Activities**

| **For year ended December 31, 2014 (thousands of Canadian dollars except per boe amounts)** | **Canada** | **United States** | **Total** |
|---|---|---|---|
| Petroleum and natural gas revenues, net of royalties | $ 1,124,279 | $ 405,618 | $ 1,529,897 |
| Less: | | | |
| Operating costs, production and mineral taxes | 272,515 | 81,334 | 353,849 |
| Transportation expense | 141,886 | — | 141,886 |
| Depreciation and depletion | 332,108 | 204,461 | 536,569 |
| Operating income | 377,770 | 119,823 | 497,593 |
| Income taxes | 195 | 53,680 | 53,875 |
| Results of operations[1] | $ 377,575 | $ 66,143 | $ 443,718 |
| Depletion rate per net boe | 16.02 | 25.30 | 18.75 |

| **For year ended December 31, 2013 (thousands of Canadian dollars except per boe amounts)** | **Canada** | **United States** | **Total** |
|---|---|---|---|
| Petroleum and natural gas revenues, net of royalties | $ 1,049,268 | $ 66,142 | $ 1,115,410 |
| Less: | | | |
| Operating costs, production and mineral taxes | 253,958 | 21,561 | 275,519 |
| Transportation expense | 158,841 | — | 158,841 |
| Depreciation and depletion | 307,845 | 21,108 | 328,953 |
| Operating income | 328,624 | 23,473 | 352,097 |
| Income taxes | — | (6,821) | (6,821) |
| Results of operations[1] | $ 328,624 | $ 30,294 | $ 358,918 |
| Depletion rate per net boe | 15.63 | 17.88 | 15.76 |

(1) Excludes corporate overhead and interest costs.