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

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

For the fiscal year ended: December 31, 2016
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:
X Annual Information Form **X** 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: 233,448,990

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 **X** 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 No. 333-171568) and Form F-3 (File No. 333-171866).

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 section titled "Special Note Regarding Forward-Looking Statements" in 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, 2016, 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, 2016, 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, 2016, 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 end of the Registrant's fiscal year ended December 31, 2016, an internal evaluation was conducted under the supervision of and with the participation of the Registrant's management, including the 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 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 Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding the required disclosure.

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, 2016, filed as Exhibit 99.2 to this Annual Report on Form 40-F, and is incorporated herein by reference.

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, 2016, 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, 2016, 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, 2016, 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, 2016, 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, 2016, 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 Ms. T. Curran, 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 7, 2017.

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, 2016.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2016 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, 2016. (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 KPMG LLP, Independent Registered Public Accounting Firm.
99.9	Consent of Deloitte LLP, Independent Registered Public Accounting Firm.
99.10	Consent of Sproule Unconventional Limited, independent engineers.
99.11	Consent of Ryder Scott Company, L.P., independent engineers.
99.12	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited).

(1) Incorporated by reference from Form 6-K filed on March 7, 2017

Exhibit 99.1



ANNUAL INFORMATION FORM

2016

MARCH 7, 2017

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APPENDICES:

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APPENDIX B REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

APPENDIX C REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

APPENDIX D AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

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 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 or **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.

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

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, 2017.

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, 2017.

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, 2017.

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, 2017.

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, 2017.

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.

Credit Facilities means our US$575 million secured, covenant-based credit facility with a syndicate of financial institutions.

CSS means cyclic steam stimulation.

Debt Indenture #1 means the amended and restated trust indenture among Baytex, as issuer, certain of its 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, July 25, 2014 and March 6, 2015.

Debt Indenture #2 means the indenture among Baytex, as issuer, certain of its 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.

MD&A means management's discussion and analysis of operating and financial results .

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 (5th Supp.), as amended, including the regulations promulgated thereunder, as amended from time to time.

Independent Engineering

Baytex Reserves Report means the report prepared by Sproule dated February 23, 2017 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, 2016*)", which is a consolidation of: (i) the report of Sproule dated January 30, 2017 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. in Canada (As of December 31, 2016)*" and (ii) the report of Ryder Scott dated February 1, 2017 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, 2016)*".

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

NI 51-101 means National Instrument 51-101 "Standards of Disclosure for Oil and 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.

Reserves Definitions

Gross means:

(a) in relation to our interest in production, reserves and contingent resources, 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.

Net means:

(a) in relation to our interest in production, reserves and contingent resources, 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.

Forecast Prices and Costs 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).

Reserves and Reserve Categories

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

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

(b) the use of established technology; and

(c) specified economic conditions (being the Forecast Prices and Costs used in the estimate).

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.

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.

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.

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:

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

(ii) 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

(iii) 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.

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 or possible) to which they are assigned.

ABBREVIATIONS

Oil and Natural Gas Liquids

bbl	barrel
Mbbl	thousand barrels
MMbbl	million barrels
NGL	natural gas liquids
bbl/d	barrels per day

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units

Other

AECO	the natural gas storage facility located at Suffield, Alberta
BOE or boe	barrel of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one bbl of oil**BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
WTI	West Texas Intermediate
LLS	Louisiana Light Sweet
WCS	Western Canadian Select
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).

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 petroleum and natural gas reserves; the development plans for our undeveloped reserves; our future abandonment and reclamation liabilities; the future development costs associated with our reserves; funding sources for development capital expenditures; our goal of building value through exploration and development activities complemented by selective acquisitions; development plans for our properties; the wide range of heavy oil investment opportunities in our Lloydminster Business Unit; our ability to reactivate our Cliffdale project at minimal expense when commodity prices warrant; our expectations regarding undeveloped lease expiries; our expectation regarding the payment of cash income taxes; our working interest production volume for 2017 based on the future net revenue disclosed in our reserves; the existence, operation and strategy of our risk management program; that we expect Edward D. LaFehr to succeed James L. Bowzer as Chief Executive Officer in May of 2017; our dividend policy; our assessment of our tax filing position for the years 2011 through 2015; 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, including with respect thereto, the 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, reclamation and abandonment obligations, tax horizon, exploration and development activities and production estimates. There are also forward-looking statements in this Annual Information Form within "*Appendix A - Contingent Resource Estimates*" as to our contingent resources, including with respect thereto, the chance of development, risked volume, risked net present value of future net revenue, capital to reach commercial production and timing of first production. Information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves and contingent resources described exist in quantities predicted or estimated, and that the reserves and contingent 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 differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; 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; 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 Baytex 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: the volatility of oil and natural gas prices; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital

markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; 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; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; we may lose access to our information technology systems; risks associated with the ownership of our securities, including 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 statements 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 will be the same in whole or in part as those referenced in the forward-looking statements 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.

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 changes in non-cash operating working capital and other operating items. We believe that this measure provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investment and potential future dividends to shareholders. However, funds from operations should not be construed as an alternative to performance measures determined in accordance with Canadian GAAP, such as cash flow from operating activities and net income (loss).

For a reconciliation of funds from operations to cash flow from operating activities, see our MD&A for the year ended December 31, 2016 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.

CORPORATE STRUCTURE

General

Baytex Energy Corp. was incorporated on October 22, 2010 pursuant to the provisions of the ABCA, as an indirect wholly-owned subsidiary of Baytex Energy Trust, for the purpose of participating in a plan of arrangement under the ABCA to effect a conversion of the legal structure from that of a trust to a corporation, such that the Corporation would be the successor to Baytex Energy Trust. The conversion took place on December 31, 2010, following which Baytex Energy Trust was terminated.

Our head and principal office is located at Suite 2800, Centennial Place, East Tower, 520 – 3 rd 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.

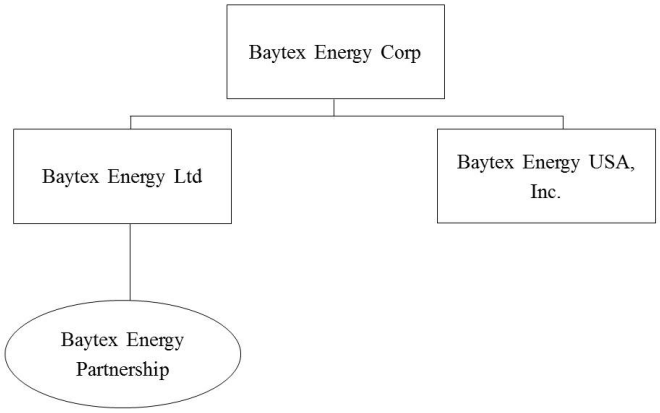
Inter-Corporate Relationships

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

Developments in the Past Three Years

2014

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 MMboe 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 an equivalent number of Common Shares on June 11, 2014. We also entered into an agreement with a Canadian chartered bank for the provision of credit facilities, which provided unsecured revolving credit facilities of approximately $1.2 billion (to replace the $850 million revolving credit facilities of Baytex Energy), 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 MMboe 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.

2015

On April 2, 2015, we completed a bought deal financing by issuing 36,455,000 Common Shares at a price of $17.35 per Common Share for aggregate gross proceeds of approximately $632.5 million. The net proceeds of the financing were used to reduce bank indebtedness.

2016

On March 31, 2016, we made significant amendments to our Credit Facilities. The amendments included reducing our Credit Facilities to US$575 million, granting our bank lending syndicate first priority security with respect to our assets and restructuring our financial covenants.

In July 2016, we disposed of our operated assets in Texas with associated production of approximately 1,000 boe/d realizing net proceeds of approximately $54.2 million.

On November 22, 2016, we entered into an asset acquisition agreement to acquire heavy oil assets in the Peace River Area for approximately $65 million. The lands are adjacent to our existing Peace River lands, added approximately 3,000 boe/d of production and more than doubled our land base in the area. The acquisition was financed through a concurrently announced bought deal financing, pursuant to which we issued 21,907,500 Common Shares at a price of $5.25 per Common Share for aggregate gross proceeds of approximately $115 million. The financing closed on December 12, 2016 and the asset acquisition closed on January 20, 2017.

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 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; a substantial decline or an extended period of the currently low prices for 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. If crude oil and natural gas prices decline or fail to increase from their current levels it could have a material adverse effect on our operations, 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 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.

Decreases to or a prolonged period of low 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 the shut-in of currently producing wells, a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

Our reserves as at December 31, 2016 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 Assumptions*". These prices are above current market prices for crude oil and natural gas. 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 undeveloped 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 oil and natural gas forecast prices decline further, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

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 a lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued which could have a dilutive effect on Shareholders.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with 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.

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.

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities could adversely affect our financial condition

Our existing Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. 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. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations. In the event that the Credit Facilities are not extended before June 2019, indebtedness under the Credit Facilities will be repayable at that time. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms. In addition, we are required to repay the Senior Notes and the 2020 Aurora Notes on maturity. See "*Description of Capital Structure*".

Failure to comply with the covenants in the agreements governing our debt could adversely affect our financial condition

We are required to comply with the covenants in our Credit Facilities and the Senior Notes. If we fail to comply with our debt covenants, are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our secured creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our Shareholders.

We are not the operator of our 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 of that acreage

Marathon Oil EF LLC (" **Marathon Oil**"), a wholly-owned subsidiary of Marathon Oil Corporation (NYSE: MRO), is the operator 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 interest and the collective best interest of all of the working interest owners of this acreage, which may not be in our best interest. We have a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of 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. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such operation.

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, Saskatchewan, the United States and Texas, all of which should be carefully considered by investors in the oil and gas industry. All 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.

At present, the newly elected President of the United States has indicated a desire to re-negotiate or withdraw from the North American Free Trade Agreement ("**NAFTA**") and a proposal has been made in the United States House of Representatives to re-write the United States tax code to include a 20% tax on all goods entering the United States. While these proposals may benefit the United States portion of our business, they would likely have a negative impact on the Canadian portion or our business. We can not anticipate what the overall impact might be. Due to the tightly integrated nature of the oil and gas industry in North America, the impact of these proposals, if acted upon, could be materially adverse to our business.

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.

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, curtailment or termination of operations and subject us to liabilities and administrative, civil and criminal penalties. Compliance costs can be significant. See "*Industry Conditions*".

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 which may have an adverse affect on our business

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, 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. The provinces of Alberta and Saskatchewan 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. 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, resulting 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 and Occupational Safety and Health Regulation*".

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).

Climate change initiatives may impose restrictions or costs on our business which have a material adverse affect on our business

Our exploration and production facilities and other operational activities emit greenhouse gases (" **GHG**"). As such, it is highly likely that any GHG emissions regulation enacted in jurisdictions where we operate will impact us.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs; increased construction and development costs; additional monitoring and compliance costs; a requirement to redesign or retrofit current facilities; permitting delays; additional costs associated with the purchase of emission credits or allowances; and reduced demand for crude oil. Additionally, if GHG emissions regulation differs by region or type of production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

The direct or indirect costs of compliance with GHG emissions regulation may have a material adverse affect on our business, financial condition, results of operations and prospects. At this time, it is not possible to predict whether compliance costs will have a material adverse affect on our business.

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions - Climate Change Regulation*".

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 to the market price of our 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. 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 our Credit Facility and 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 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. To the extent that our current hedging agreements are beneficial to us, these benefits will only be realized for the period and for the commodity quantities in those contracts. In addition, there is no certainty that we will be able to obtain additional hedges at prices that have an equivalent benefit to us, 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.

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

We deliver our products through gathering, processing and pipeline systems which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems 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. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. 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.

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 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 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. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

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.

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. 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.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves at acceptable costs. Without these reserves additions, our reserves will deplete and as a consequence production from and the average reserves life of our properties will decline, which may result in a reduction in the value of our Common Shares.

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 audit and reassessment by the applicable taxation authority. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details see *"Legal Proceedings and Regulatory Actions"*.

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.

Income tax laws and government incentive programs relating to the oil and gas industry may 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 and such variances could be material.

The contingent resources estimates included as Appendix A to 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 the: (i) 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) 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 and prospects.

We are subject to risk of default by the counterparties to our contracts and our counterparties may deem us to be a default risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flows and financial position. Conversely, our counterparties may deem us to be at risk of defaulting on our contractual obligations. These counterparties may require that we provide additional credit assurances by prepaying anticipated expenses or posting letters of credit, which would decrease our available liquidity.

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

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as CSS and SAGD, 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 CSS, SAGD 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.

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: labour costs; the cost of catalysts and chemicals; the cost of natural gas and electricity; power outages; produced sand causing issues of erosion, hot spots and corrosion; reliability of facilities; maintenance costs; the cost to transport sales products; and the cost to dispose of certain by-products.

Our information technology systems are subject to certain risks

We utilize a number of information technology systems for the administration and management of our business. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although our information technology systems are considered to be secure, if an unauthorized third party is able to access the systems then such unauthorized access may compromise our business in a materially adverse manner.

Risks Relating to Ownership of our Securities

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, our principal office is located in Calgary, Alberta and a substantial portion of our assets are located outside the United States. 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 their assets 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 plus 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 estimates of contingent resources as Appendix A to this Annual Information Form. 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. 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

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

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

Overview

We are engaged in the business of acquiring, developing, exploiting and holding interests in petroleum and natural gas properties and related assets in Canada (in Alberta and Saskatchewan) and in the United States (in Texas).

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 Baytex.

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 Baytex.

Personnel

As at December 31, 2016, we had 147 employees in our Calgary head office, 22 employees in our Houston office and 83 employees in our field operations.

STATEMENT OF RESERVES DATA

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. The statement of reserves data and other oil and natural gas information set forth below is dated February 23, 2017, with an effective date of December 31, 2016. The preparation date of the statement is January 30, 2017, in the case of Sproule, and February 1, 2017, in the case of Ryder Scott. Sproule prepared the Baytex Reserves 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, 2016 forecast price and cost assumptions.

Disclosure of Reserves Data

The tables below are a combined summary as at December 31, 2016 of our proved, probable and possible heavy oil, bitumen, light and medium oil, tight oil, NGL, conventional natural gas and shale gas reserves and the net present value of future net revenue attributable to such reserves evaluated in the Baytex Reserves Report. Our reserves are located in Canada (in Alberta and Saskatchewan) and the United States (in Texas).

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. The tables summarize the data contained in the Baytex Reserve Report and, as a result, may contain slightly different numbers and columns in the tables may not add due to rounding. 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 "*Selected Terms* - *Reserves Definitions*", "- *Reserves and Reserve Categories*" and "- *Development and Production Status*" 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, 2016
FORECAST PRICES AND COSTS

CANADA

	LIGHT AND MEDIUM OIL		HEAVY OIL		BITUMEN	
RESERVES CATEGORY	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mbbl)**	**Net (Mbbl)**
PROVED:						
Developed Producing	1,985	1,858	25,923	19,717	382	347
Developed Non-Producing	—	—	2,609	2,223	7,655	7,072
Undeveloped	308	316	18,343	16,172	5,428	4,357
TOTAL PROVED	2,293	2,174	46,875	38,112	13,465	11,776
PROBABLE	1,794	1,598	29,325	23,955	55,835	44,311
TOTAL PROVED PLUS PROBABLE	4,087	3,773	76,199	62,068	69,300	56,086

CANADA

RESERVES CATEGORY	CONVENTIONAL NATURAL GAS (1)		NATURAL GAS LIQUIDS (2)		TOTAL RESERVES	
	Gross (MMcf)	Net(MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:						
Developed Producing	49,201	43,294	1,246	925	37,735	30,063
Developed Non-Producing	22	35	—	1	10,267	9,302
Undeveloped	66,711	60,907	1,345	1,114	36,542	32,110
TOTAL PROVED	115,933	104,236	2,590	2,039	84,544	71,475
PROBABLE	89,206	76,579	3,198	2,479	105,019	85,106
TOTAL PROVED PLUS PROBABLE	205,139	180,816	5,788	4,518	189,564	156,581

UNITED STATES

RESERVES CATEGORY	TIGHT OIL		SHALE GAS		CONVENTIONAL NATURAL GAS (1)	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	19,242	14,101	60,929	45,025	27,530	20,206
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	30,472	22,344	112,899	83,277	28,553	20,950
TOTAL PROVED	49,714	36,444	173,828	128,302	56,083	41,156
PROBABLE	8,399	6,161	59,075	43,371	8,906	6,543
TOTAL PROVED PLUS PROBABLE	58,113	42,605	232,903	171,674	64,988	47,699
POSSIBLE (3)	19,269	14,160	81,346	59,866	18,327	13,477
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)	77,381	56,765	314,249	231,540	83,315	61,176

UNITED STATES

RESERVES CATEGORY	NATURAL GAS LIQUIDS (2)		TOTAL RESERVES	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	26,907	19,861	60,892	44,833
Developed Non-Producing	—	—	—	—
Undeveloped	53,194	39,199	107,242	78,914
TOTAL PROVED	80,102	59,059	168,134	123,747
PROBABLE	28,627	21,025	48,355	35,505
TOTAL PROVED PLUS PROBABLE	108,728	80,084	216,490	159,252
POSSIBLE (3)	37,430	27,545	73,310	53,928
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)	146,158	107,629	289,800	213,180

TOTAL

RESERVES CATEGORY	TIGHT OIL		LIGHT AND MEDIUM OIL		HEAVY OIL	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)
PROVED:						
Developed Producing	19,242	14,101	1,985	1,858	25,923	19,717
Developed Non-Producing	—	—	—	—	2,609	2,223
Undeveloped	30,472	22,344	308	316	18,343	16,172
TOTAL PROVED	49,714	36,444	2,293	2,174	46,875	38,112
PROBABLE	8,399	6,161	1,794	1,598	29,325	23,955
TOTAL PROVED PLUS PROBABLE	58,113	42,605	4,087	3,773	76,199	62,068
POSSIBLE (3)(4)	19,269	14,160	—	—	—	—
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)(4)	77,381	56,765	4,087	3,773	76,199	62,068

TOTAL

RESERVES CATEGORY	BITUMEN		SHALE GAS		CONVENTIONAL NATURAL GAS (1)	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (MMcf)	Net (MMcf)
PROVED:						
Developed Producing	382	347	60,929	45,025	76,731	63,501
Developed Non-Producing	7,655	7,072	—	—	21	35
Undeveloped	5,428	4,357	112,899	83,277	95,264	81,857
TOTAL PROVED	13,465	11,776	173,828	128,302	172,016	145,393
PROBABLE	55,835	44,311	59,075	43,371	98,112	83,123
TOTAL PROVED PLUS PROBABLE	69,300	56,086	232,903	171,674	270,127	228,515
POSSIBLE (3)(4)	—	—	81,346	59,866	18,327	13,477
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)(4)	69,300	56,086	314,249	231,540	288,455	241,992

TOTAL

RESERVES CATEGORY	NATURAL GAS LIQUIDS (2)		TOTAL RESERVES	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	28,153	20,786	98,627	74,896
Developed Non-Producing	—	1	10,267	9,303
Undeveloped	54,539	40,312	143,784	111,024
TOTAL PROVED	82,692	61,099	252,678	195,223
PROBABLE	31,825	23,504	153,375	120,611
TOTAL PROVED PLUS PROBABLE	114,516	84,602	406,053	315,833
POSSIBLE (3)(4)	37,430	27,544	73,310	53,928
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)(4)	151,946	112,147	479,364	369,761

Notes:
(1) Conventional natural gas includes associated, non-associated and solution gas.
(2) Natural gas liquids includes condensate.
(3) 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.
(4) The total possible reserves include only possible reserves from the Eagle Ford properties. 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, 2016
FORECAST PRICES AND COSTS

CANADA	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**					**UNIT VALUE BEFORE TAX**
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	523,531	467,725	420,445	381,377	349,129	13.99
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485	13.03
Undeveloped	534,063	386,333	283,491	210,063	156,424	8.83
TOTAL PROVED	1,300,931	1,022,460	825,145	681,804	575,038	11.54
PROBABLE	2,182,301	1,195,885	723,254	467,328	314,943	8.50
TOTAL PROVED PLUS PROBABLE	3,483,233	2,218,345	1,548,399	1,149,132	889,981	9.89

UNITED STATES	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**					**UNIT VALUE BEFORE TAX**
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	1,674,035	1,286,547	1,047,642	888,644	776,258	23.37
Developed Non-Producing	—	—	—	—	—	—
Undeveloped	2,328,597	1,416,589	914,698	615,838	426,453	11.59
TOTAL PROVED	4,002,633	2,703,136	1,962,340	1,504,482	1,202,712	15.86
PROBABLE	1,053,807	604,633	376,915	249,067	171,338	10.62
TOTAL PROVED PLUS PROBABLE	5,056,440	3,307,769	2,339,255	1,753,549	1,374,049	14.69
POSSIBLE [(1)]	2,370,364	1,417,370	938,108	668,947	504,293	17.40
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [(1)]	7,426,804	4,725,138	3,277,363	2,422,496	1,878,343	15.37

TOTAL	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**					**UNIT VALUE BEFORE TAX**
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**	**10% $/boe**
PROVED:						
Developed Producing	2,197,567	1,754,271	1,468,087	1,270,022	1,125,387	19.60
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485	13.03
Undeveloped	2,862,660	1,802,922	1,198,190	825,901	582,878	10.79
TOTAL PROVED	5,303,564	3,725,596	2,787,485	2,186,286	1,777,750	14.28
PROBABLE	3,236,109	1,800,518	1,100,168	716,395	486,281	9.12
TOTAL PROVED PLUS PROBABLE	8,539,673	5,526,114	3,887,653	2,902,681	2,264,031	12.31
POSSIBLE [(1)(2)]	2,370,364	1,417,370	938,108	668,947	504,293	17.40
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [(1)(2)]	10,910,037	6,943,484	4,825,762	3,571,628	2,768,324	13.05

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 properties. 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, 2016
FORECAST PRICES AND COSTS

CANADA	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	523,531	467,725	420,445	381,377	349,129
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485
Undeveloped	412,218	297,083	216,492	158,688	116,297
TOTAL PROVED	1,179,087	933,210	758,145	630,429	534,910
PROBABLE	1,604,045	858,335	502,476	311,126	198,261
TOTAL PROVED PLUS PROBABLE	2,783,132	1,791,545	1,260,621	941,555	733,171

UNITED STATES	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,589,270	1,236,432	1,016,310	868,054	762,105
Developed Non-Producing	—	—	—	—	—
Undeveloped	1,604,389	986,329	641,333	432,827	298,765
TOTAL PROVED	3,193,659	2,222,760	1,657,644	1,300,882	1,060,870
PROBABLE	679,043	387,921	241,254	158,997	108,813
TOTAL PROVED PLUS PROBABLE	3,872,702	2,610,681	1,898,897	1,459,878	1,169,682
POSSIBLE [2]	1,528,085	922,585	621,008	452,503	349,451
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [2]	5,400,787	3,533,266	2,519,905	1,912,382	1,519,133

TOTAL	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	2,112,801	1,704,156	1,436,755	1,249,432	1,111,233
Developed Non-Producing	243,337	168,403	121,209	90,363	69,485
Undeveloped	2,016,607	1,283,412	857,825	591,516	415,062
TOTAL PROVED	4,372,746	3,155,971	2,415,789	1,931,311	1,595,780
PROBABLE	2,283,088	1,246,255	743,730	470,123	307,074
TOTAL PROVED PLUS PROBABLE	6,655,834	4,402,226	3,159,519	2,401,434	1,902,854
POSSIBLE [2][3]	1,528,085	922,585	621,008	452,503	349,451
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [2][3]	8,183,919	5,324,811	3,780,526	2,853,937	2,252,305

Notes:

(1) The after-tax net present value of future net revenue from our oil and gas properties reflects the tax burden on the properties on a theoretical stand-alone basis. It does not consider our corporate structure or any tax planning and therefore does not provide an estimate of the cumulative after-tax value of our consolidated business entities, which may be significantly different.

(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 properties. The possible reserves associated with the Canadian properties have not been evaluated.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

($000s)	REVENUE	ROYALTIES	OPERAT-ING COSTS	DEVELOP-MENT COSTS	WELL ABANDON-MENT COSTS(1)	FUTURE NET REVENUE BEFORE INCOME TAXES	INCOME TAXES	FUTURE NET REVENUE AFTER INCOME TAXES
TOTAL PROVED RESERVES								
Canada	3,746,370	594,279	1,323,625	432,275	95,259	1,300,931	121,845	1,179,087
United States	10,791,104	3,378,708	2,015,800	1,342,613	51,351	4,002,633	808,974	3,193,659
Total	14,537,475	3,972,988	3,339,425	1,774,888	146,610	5,303,564	930,818	4,372,746
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	10,203,618	1,848,010	3,498,590	1,239,406	134,378	3,483,233	700,101	2,783,132
United States	14,045,481	4,402,316	2,674,949	1,847,182	64,594	5,056,440	1,183,738	3,872,702
Total	24,249,099	6,250,327	6,173,539	3,086,588	198,972	8,539,673	1,883,839	6,655,834
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE RESERVES (2)(3)								
Canada	10,203,618	1,848,010	3,498,590	1,239,406	134,378	3,483,233	700,101	2,783,132
United States	19,149,972	6,000,174	3,400,342	2,247,724	74,928	7,426,804	2,026,017	5,400,787
Total	29,353,590	7,848,184	6,898,933	3,487,130	209,306	10,910,037	2,726,118	8,183,919

Notes:
(1) Includes well abandonment and reclamation based on estimates by the Corporation for all reserves wells, producing and undeveloped, but does not include abandonment and surface reclamation costs for any existing facilities.
(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 properties. The possible reserves associated with the Canadian properties have not been evaluated.

FUTURE NET REVENUE BY PRODUCT TYPE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCT TYPE	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/boe) [1]
Proved	Light and Medium Crude Oil (including solution gas and associated byproducts)	37,342	15.93
	Heavy Oil (including solution gas and associated byproducts)	524,619	11.44
	Bitumen (including solution gas and associated byproducts)	174,684	14.83
	Tight Oil (including solution gas and associated byproducts)	936,996	18.70
	Natural Gas (associated and non-associated) (including associated byproducts)	88,499	7.71
	Shale Gas (including associated byproducts)	1,025,344	13.92
	Total	2,787,484	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	50,399	11.02
	Heavy Oil (including solution gas and associated byproducts)	827,505	11.79
	Bitumen (including solution gas and associated byproducts)	489,051	8.72
	Tight Oil (including solution gas and associated byproducts)	1,058,387	18.12
	Natural Gas (associated and non-associated) (including associated byproducts)	181,443	7.05
	Shale Gas (including associated byproducts)	1,280,868	12.70
	Total	3,887,653	
Proved plus Probable plus Possible [2][3]	Light and Medium Crude Oil (including solution gas and associated byproducts)	50,399	11.02
	Heavy Oil (including solution gas and associated byproducts)	827,505	11.79
	Bitumen (including solution gas and associated byproducts)	489,051	8.72
	Tight Oil (including solution gas and associated byproducts)	1,439,811	18.68
	Natural Gas (associated and non-associated) (including associated byproducts)	181,443	7.05
	Shale Gas (including associated byproducts)	1,837,552	13.50
	Total	4,825,762	

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 properties. The possible reserves associated with the Canadian properties have not been evaluated.

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. The reference pricing used in the Baytex Reserves Report is as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2016[1]

	Oil			Natural Gas				
Year	WTI Cushing Oklahoma[2] ($US/bbl)	Canada Light Sweet Crude 40° API[3] ($Cdn/bbl)	Western Canadian Select 20.5° API[4] ($Cdn/bbl)	Henry Hub[5] ($US/Mmbtu)	AECO-C Spot[6] ($Cdn/MMbtu)	Operating Cost Inflation Rate[7] (%/Yr)	Capital Cost Inflation Rate[7] (%/Yr)	Exchange Rate[8] ($US/$Cdn)
Historical								
2012	94.19	86.57	73.08	2.79	2.43	1.0	4.5	1.001
2013	97.98	93.27	74.93	3.68	3.13	1.0	0.7	0.971
2014	93.00	93.99	81.06	4.28	4.50	2.0	(1.0)	0.905
2015	48.80	57.45	44.83	2.63	2.70	1.8	(23.2)	0.783
2016	43.32	52.80	38.30	2.55	2.18	1.6	(3.3)	0.755
Forecast[9]								
2017	55.00	65.58	53.12	3.50	3.44	—	—	0.780
2018	65.00	74.51	61.85	3.50	3.27	2.0	2.0	0.820
2019	70.00	78.24	64.94	3.50	3.22	2.0	2.0	0.850
2020	71.40	80.64	66.93	4.00	3.91	2.0	2.0	0.850
2021	72.83	82.25	68.27	4.08	4.00	2.0	2.0	0.850
2022	74.28	83.90	69.64	4.16	4.10	2.0	2.0	0.850
2023	75.77	85.58	71.03	4.24	4.19	2.0	2.0	0.850
2024	77.29	87.29	72.45	4.33	4.29	2.0	2.0	0.850
2025	78.83	89.03	73.90	4.42	4.40	2.0	2.0	0.850
2026	80.41	90.81	75.38	4.50	4.50	2.0	2.0	0.850
2027	82.02	92.63	76.88	4.59	4.61	2.0	2.0	0.850

Notes:
(1) Each price from the Sproule forecast was adjusted for quality differentials and transportation costs applicable to the specified product and evaluation area.
(2) Price used in the preparation of tight 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 shale gas reserves in the United States.
(6) Price used in the preparation of natural gas reserves in Canada.
(7) Inflation rates for forecasting prices and costs.
(8) Exchange rate used to generate the benchmark reference prices in this table.
(9) After 2027 prices and costs escalate at 2.0% annually and the exchange rate remains 0.850.

Weighted average prices realized by us for the year ended December 31, 2016, excluding hedging activities, were $ 26.41/bbl for heavy oil, $27.20/bbl for bitumen, $46.21/bbl for light oil, $50.60/bbl for tight oil, $17.16/bbl for NGL, $3.21/Mcf for shale gas and $2.01/Mcf for natural gas.

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

CANADA	HEAVY OIL [1]			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2015	65,030	37,883	102,913	13,758	55,882	69,640
Extensions	227	1,255	1,482	—	—	—
Infill Drilling	1,037	1,024	2,062	—	—	—
Improved Recovery	—	0	0	—	—	—
Technical Revisions	(8,004)	(9,862)	(17,866)	476	(216)	260
Discoveries	—	—	—	—	—	—
Acquisitions	34	13	48	—	—	—
Dispositions	(685)	(804)	(1,489)	—	—	—
Economic Factors	(2,700)	(185)	(2,885)	(204)	170	(35)
Production	(8,065)	—	(8,065)	(565)	—	(565)
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300

CANADA	LIGHT AND MEDIUM OIL			CONVENTIONAL NATURAL GAS [2]		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	2,902	2,420	5,323	92,000	85,538	177,538
Extensions	—	—	—	11	3,682	3,693
Infill Drilling	—	—	—	94	52	146
Improved Recovery		—	—	—	—	—
Technical Revisions	141	(425)	(284)	39,373	2,693	42,066
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	2,531	641	3,172
Dispositions	(25)	(8)	(32)	(1,998)	(568)	(2,565)
Economic Factors	(214)	(194)	(408)	(1,432)	(2,833)	(4,265)
Production	(511)	—	(511)	(14,645)	—	(14,645)
December 31, 2016	2,293	1,794	4,087	115,933	89,206	205,139

CANADA	NATURAL GAS LIQUIDS [3]			OIL EQUIVALENT		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2015	2,745	3,081	5,826	99,768	113,522	213,290
Extensions	—	148	148	229	2,017	2,245
Infill Drilling	—	—	—	1,053	1,033	2,086
Improved Recovery	—	—	—	—	—	—
Technical Revisions	290	6	296	(535)	(10,048)	(10,583)
Discoveries	—	—	—	—	—	—
Acquisitions	106	27	133	562	147	709
Dispositions	(62)	(18)	(80)	(1,105)	(924)	(2,029)
Economic Factors	(25)	(46)	(71)	(3,381)	(729)	(4,110)
Production	(463)	—	(463)	(12,046)	—	(12,046)
December 31, 2016	2,590	3,198	5,788	84,544	105,019	189,564

UNITED STATES	TIGHT OIL [4]			SHALE GAS [4]		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	49,215	4,551	53,765	194,767	40,038	234,805
Extensions	—	—	—	—	—	—
Infill Drilling	6,948	5,863	12,812	33,171	43,893	77,064
Improved Recovery	—	—	—	—	—	—
Technical Revisions	(1,723)	(2,027)	(3,750)	(41,058)	(25,187)	(66,246)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(831)	(52)	(883)	—	—	—
Economic Factors	3	63	67	334	331	665
Production	(3,898)	—	(3,898)	(13,386)	—	(13,386)
December 31, 2016	49,714	8,399	58,113	173,828	59,075	232,903

UNITED STATES	CONVENTIONAL NATURAL GAS [2]			NATURAL GAS LIQUIDS [3][4]		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2015	56,880	5,991	62,871	83,710	16,263	99,972
Extensions	—	—	—	—	—	—
Infill Drilling	7,656	5,041	12,697	15,692	21,905	37,597
Improved Recovery	—	—	—	—	—	—
Technical Revisions	(2,498)	(2,173)	(4,671)	(12,966)	(9,668)	(22,634)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(618)	(52)	(669)	(87)	(7)	(94)
Economic Factors	4	97	101	120	134	254
Production	(5,341)	—	(5,341)	(6,367)	—	(6,367)
December 31, 2016	56,083	8,906	64,988	80,102	28,627	108,728

UNITED STATES	OIL EQUIVALENT		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2015	174,865	28,485	203,350
Extensions	—	—	—
Infill Drilling	29,445	35,924	65,369
Improved Recovery	—	—	—
Technical Revisions	(21,948)	(16,255)	(38,203)
Discoveries	—	—	—
Acquisitions	—	—	—
Dispositions	(1,021)	(67)	(1,088)
Economic Factors	179	269	448
Production	(13,386)	—	(13,386)
December 31, 2016	168,134	48,356	216,490

TOTAL	HEAVY OIL [1]			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2015	65,030	37,883	102,913	13,758	55,882	69,640
Extensions	227	1,255	1,482	—	—	—
Infill Drilling	1,037	1,024	2,062	—	—	—
Improved Recovery	—	—	—	—	—	—
Technical Revisions	(8,004)	(9,862)	(17,866)	476	(216)	260
Discoveries	—	—	—	—	—	—
Acquisitions	34	13	48	—	—	—
Dispositions	(685)	(804)	(1,489)	—	—	—
Economic Factors	(2,700)	(185)	(2,885)	(204)	170	(35)
Production	(8,065)	—	(8,065)	(565)	—	(565)
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300

TOTAL	LIGHT AND MEDIUM OIL			TIGHT OIL [4]		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2015	2,902	2,420	5,323	49,215	4,551	53,765
Extensions	—	—	—	—	—	—
Infill Drilling	—	—	—	6,948	5,863	12,812
Improved Recovery	—	—	—	—	—	—
Technical Revisions	141	(425)	(284)	(1,723)	(2,027)	(3,750)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(25)	(8)	(32)	(831)	(52)	(883)
Economic Factors	(214)	(194)	(408)	3	63	67
Production	(511)	—	(511)	(3,898)	—	(3,898)
December 31, 2016	2,293	1,794	4,087	49,714	8,399	58,113

TOTAL	NATURAL GAS LIQUIDS [3][4]			SHALE GAS [4]		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2015	86,454	19,344	105,798	194,767	40,038	234,805
Extensions	—	148	148	—	—	—
Infill Drilling	15,692	21,905	37,597	33,171	43,893	77,064
Improved Recovery	—	—	—	—	—	—
Technical Revisions	(12,676)	(9,662)	(22,338)	(41,058)	(25,187)	(66,246)
Discoveries	—	—	—	—	—	—
Acquisitions	106	27	133	—	—	—
Dispositions	(149)	(24)	(174)	—	—	—
Economic Factors	95	88	183	334	331	665
Production	(6,830)	—	(6,830)	(13,386)	—	(13,386)
December 31, 2016	82,692	31,825	114,516	173,828	59,075	232,903

TOTAL	CONVENTIONAL NATURAL GAS (2)			OIL EQUIVALENT		
	Proved (MMcf)	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2015	148,880	91,529	240,409	274,633	142,008	416,640
Extensions	11	3,682	3,693	229	2,017	2,245
Infill Drilling	7,749	5,094	12,843	30,497	36,957	67,455
Improved Recovery	—	—	—	—	—	—
Technical Revisions	36,875	520	37,395	(22,483)	(26,303)	(48,786)
Discoveries	—	—	—	—	—	—
Acquisitions	2,531	641	3,172	562	147	709
Dispositions	(2,615)	(619)	(3,235)	(2,126)	(992)	(3,118)
Economic Factors	(1,428)	(2,735)	(4,163)	(3,202)	(460)	(3,661)
Production	(19,987)	—	(19,987)	(25,431)	—	(25,431)
December 31, 2016	172,016	98,112	270,127	252,679	153,375	406,053

Note:
(1) Technical revisions related to heavy oil are largely attributed to revised reservoir and mobility mapping and well performance.
(2) Conventional natural gas includes associated, non-associated and solution gas.
(3) Natural gas liquids includes condensate.
(4) Technical revisions for tight oil, natural gas liquids and shale gas were largely the result of the development of additional horizons, primarily the Upper Eagle Ford. These new horizons are now proven and have producing wells and new locations, which reduced the expected recovery from a portion of the existing wells. These technical revisions were more than offset by reserve additions classified as “infill drilling”.

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 annually. We reduce risk by technically assessing the prior year's results from our development programs before committing additional capital. Furthermore, planned activity levels vary each year due to factors such as prevailing commodity prices, capital availability, operational spacing considerations and regulatory processes. This approach means that in most cases it will take longer than three years to develop our proved undeveloped reserves and longer than five years to develop our proved plus probable undeveloped reserves. With the exception of the Gemini SAGD Project, we plan to develop the majority of our proved undeveloped reserves over the next five years and our probable undeveloped reserves over the next seven years.

At our Gemini SAGD project, steam generation represents a large proportion of the capital and operating costs, therefore, our development plans anticipate that in order to make the most efficient use of our steam generating and oil treating facilities, the drilling and steaming of wells would take place over the next 27 years. We have booked 0.5 Mbbls of proved undeveloped reserves and 43.4 Mbbls of probable undeveloped reserves to the Gemini SAGD project.

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed during, and the volume booked at year-end for, the three most recently completed financial years.

	Light and Medium Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Bitumen 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
2014	—	307	28,077	28,077	4,490	29,367	—	8,295
2015	—	99	3,122	28,812	1,506	27,362	—	5,429
2016	—	308	4,561	30,472	1,215	18,343	—	5,428

	Conventional Natural Gas Gross (Mmcf)		Shale Gas Gross (Mmcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2014	29,412	51,407	139,352	139,352	56,850	57,802
2015	7,346	64,275	17,555	138,014	8,540	59,273
2016	5,038	95,264	20,050	112,899	9,817	54,539

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were attributed during, and the volume booked at year-end for, the three most recently completed financial years.

	Light and Medium Oil Gross (Mbbl)		Tight Oil Gross (Mbbl)		Heavy Oil Gross (Mbbl)		Bitumen 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
2014	—	1,532	2,415	2,415	3,884	21,824	26,904	63,989
2015	—	1,703	287	1,877	4,265	24,383	—	47,218
2016	—	1,120	5,789	5,808	2,268	20,256	—	47,219

	Conventional Natural Gas Gross (Mmcf)		Shale Gas Gross (Mmcf)		Natural Gas Liquids Gross (Mbbl)	
Year	First Attributed	Booked at Year End	First Attributed	Booked at Year End	First Attributed	Booked at Year End
2014	26,941	54,060	16,714	16,714	8,347	9,572
2015	11,069	75,819	21,447	33,122	9,068	15,796
2016	8,687	81,161	43,066	51,955	21,703	28,214

Significant Factors or Uncertainties

In the event that prices for oil and gas are not consistent with those used to prepare the Baytex Reserves Report, the volume of our reserves, their net present value and our expected revenues will differ, perhaps materially so, from those stated in the Baytex Reserves Report.

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, 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 natural 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 below those used to prepare the Baytex Reserves Report, 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 "*Risk Factors*".

In connection with our operations, we will be liable for our share of ongoing environmental obligations and for the ultimate reclamation of those surface leases, wells and facilities held by us which have not been included in the calculation of future net revenue as they are not associated with our reserves. The additional liability associated with these existing surface leases, wells and facilities which was not included when estimating future net revenue, is estimated to be $499.4 million ($68.9 million discounted at 10 percent).

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, 2016
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
2017	68,851	82,101	171,137	252,541	239,989	334,642
2018	130,105	273,039	192,088	247,526	322,193	520,564
2019	118,115	279,336	200,143	267,560	318,258	546,896
2020	63,573	162,254	168,708	245,334	232,280	407,588
2021	36,081	138,682	215,465	282,523	251,546	421,204
Remaining	15,550	303,996	395,073	551,698	410,623	855,693
Total (undiscounted)	432,275	1,239,406	1,342,613	1,847,182	1,774,888	3,086,588

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 and the costs thereof. 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 evaluate our possible reserves effective December 31, 2016 in the Eagle Ford property. The possible reserves reflect the significant upside potential of the Austin Chalk, Upper Eagle Ford and Lower Eagle Ford formations. 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.

Contingent Resources

We commissioned Sproule to conduct an evaluation effective December 31, 2016 of our contingent resources in Alberta and Saskatchewan. We commissioned Ryder Scott to audit our internal assessment of our contingent resources in the Eagle Ford play in Texas, effective December 31, 2016. A summary of these contingent resources estimates is provided in Appendix A.

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, 2016. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2016. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production for the year ended December 31, 2016, except where otherwise indicated.

Our crude oil and natural gas operations are organized into four business units: Lloydminster, Peace River, Conventional and United States. These business units have a portfolio of mineral leases, with operated and/or 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). This comprehensive technical approach is intended to result in thorough identification and evaluation of exploration, development and acquisition opportunities and cost-efficient execution of those opportunities.

We endeavour to add value through internal property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area within the Peace River Business Unit and our historical area of emphasis around west-central Saskatchewan and northeast Alberta within the Lloydminster Business Unit. Tight gas development in Canada is focused on the Pembina area in west-central Alberta within the Conventional Business Unit and light oil and gas development will focus on the Sugarkane area located in the core of the liquids-rich Eagle Ford shale within the United States Business Unit.

Principal Properties

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



Lloydminster Business Unit

The Lloydminster Business Unit accounted for approximately 15% of total production in 2016. 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 blended with diluents. 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, before the addition of diluents.

In 2016, production in the Lloydminster Business Unit averaged approximately 10,170 boe/d, which was comprised of 8,391 bbl/d of heavy oil, 1,544 bbl/d of bitumen, and 1,382 Mcf/d of natural gas. Our net undeveloped lands in the Lloydminster Business Unit totaled approximately 193,087 acres at year-end 2016.

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 historically been key to maintaining our overall production rate. Our inventory of heavy oil projects allows us to select from a wide range of investment opportunities as economic conditions warrant.

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 2016 was approximately 608 bbl/d of heavy oil and 365 Mcf/d of natural gas (669 boe/d).

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. Regulatory approval has been obtained for the construction and operation 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 with a 600 meter 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 and produced until April 2015, when an electrical fire at the facility resulted in damage to equipment and resulted in the project being suspended. During the 11-month production phase, the well produced over 200,000 bbls of oil at an average rate of approximately 590 bopd and a steam-oil ratio of 2.42 barrels of steam per barrel of oil.

In December 2014, 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. This scheme amendment application was approved by the Alberta Energy Regulator on September 30, 2016.

At year-end 2016, Baytex had 76,981 net undeveloped acres in the Cold Lake/Ardmore area.

Soda Lake, Saskatchewan: The Soda Lake property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. Average production in 2016 was approximately 2,095 bbl/d of heavy oil and 108 Mcf/d of natural gas (2,113 boe/d). At year-end 2016, Baytex had 8,488 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. Average production in 2016 was approximately 1,377 bbl/d of heavy oil. At year-end 2016, Baytex had 7,702 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 and thermal assets averaged approximately 858 bbl/d of heavy oil, 1,544 bbl/d of bitumen, 5 bbl/d of light oil and NGL and 20 Mcf/d of natural gas (2,410 boe/d). At year-end 2016, Baytex had 37,240 net undeveloped acres in this area.

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. Average production during 2016 was approximately 1,858 bbl/d of heavy oil and 464 Mcf/d of natural gas (1,935 boe/d). At year-end 2016, Baytex had 5,288 net undeveloped acres in this area.

Peace River Business Unit

The Peace River Business Unit produces heavy gravity crude oil, bitumen, and natural gas mainly from the Bluesky formation in the Peace River region of north west Alberta. This production accounted for approximately 21% of total Baytex production in 2016. The following is a brief description of the principal property in the Peace River Business Unit:

Peace River, Alberta: Baytex holds a total of 338 net sections of oil sands leases in the Peace River area, which includes the legacy Harmon Valley area and the Reno area. During 2016, production from the Peace River area averaged 13,651 bbl/d of heavy oil, and 4,180 Mcf/d of natural gas (14,348 boe/d). At year-end 2016, Baytex had 180,199 net undeveloped acres of oil sands leases 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 300 bbl/d per well without employing more cost-intensive secondary and tertiary recovery methods. The majority of Baytex's development activity is focused on primary production through this multi-lateral well strategy. However, in some portions of the land base, the reservoir characteristics require thermal stimulation to achieve production. Baytex has demonstrated that CSS can be utilized to extract reserves which are not producible through primary production techniques. If supported by commodity prices, our Cliffdale CSS project, which was suspended in Q3 2015, could be reactivated with minimal expenditure.

Subsequent to year-end 2016, Baytex completed the acquisition of an additional 392 net sections of oil sands leases adjacent to our current oil sands leases, including 219,520 net acres of undeveloped land, along with associated production of approximately 3,000 boe/d.

Conventional Business Unit

The Conventional Business Unit produces light oil, natural gas and natural gas liquids from various fields in northern, southeast and central Alberta. This production accounted for approximately 12% of total Baytex production in 2016. During 2016, production from this business unit averaged 8,419 boe/d which was comprised of 2,675 bbl/d of light oil and NGL and 34,453 Mcf/d of natural gas. At year-end 2016, we had 139,313 net acres of undeveloped land in this business unit

The following is a brief description of the principal property within the Conventional Business Unit:

Pembina, Alberta: 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. Baytex's oil production in this area is treated at third party-operated oil batteries. Natural gas production is delivered to a combination of four mid-stream gas processing facilities and two producer-operated gas processing facilities. Baytex owns a working interest in one of the midstream-operated gas processing facilities. Production from this area during 2016 averaged 1,367 bbl/d of light oil and NGL and 26,799 Mcf/d of natural gas (5,834 boe/d). Baytex participated in the drilling of one (1.0 net) well in this area in 2016, resulting in one (1.0 net) natural gas well. This well was completed with multi-stage fracture stimulations. At year-end 2016, Baytex had 29,187 net undeveloped acres in this area.

United States Business Unit

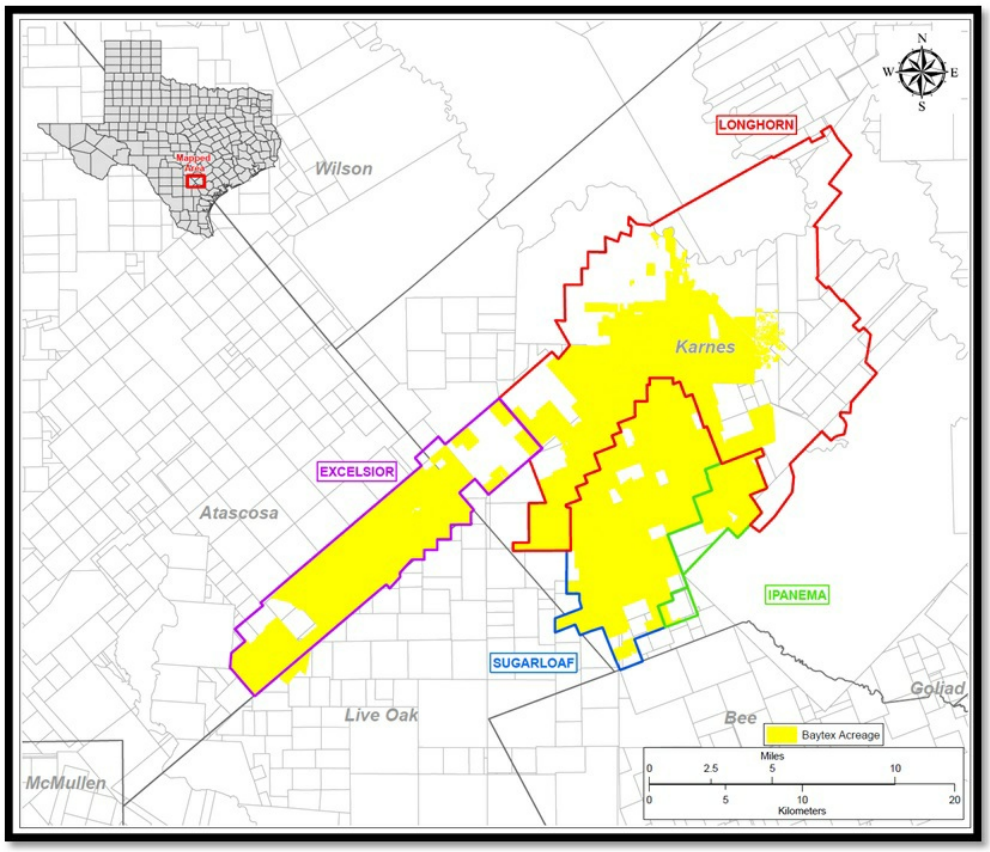
On June 11, 2014, Baytex acquired an interest in approximately 80,200 (22,200 net) acres in the Sugarkane area located in South Texas in the core of the liquids-rich Eagle Ford shale through the acquisition of Aurora. In July 2016, we disposed of substantially all of our operated acreage, such that our assets now include non-operated working interests in approximately 79,000 (20,100 net) acres within the Eagle Ford, comprising four areas of mutual interest (Sugarloaf, Longhorn, Ipanema and Excelsior) in the Sugarkane area, 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.

Additional leasehold held in East Texas (2,327 net acres) does not meet Baytex's development or economic criteria but will remain in inventory until the leases expire as their terms come due.

The following table sets forth our gross and net acreage for our United States assets as at December 31, 2016:

	Gross Acreage	Net Acreage
Sugarloaf AMI	24,145	6,768
Longhorn AMI	31,034	9,886
Ipanema AMI	4,771	1,737
Excelsior AMI	19,085	1,745
Sugarkane area total:	79,035	20,136
Other Eagle Ford	87	87
East Texas (operated)	2,384	2,327
Total	81,506	22,550

The map below highlights the geographic location of our Eagle Ford properties and areas of mutual interest in the Sugarkane area:



Production from the non-operated assets is processed at 13 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 or for export via trucks to refineries;
- saline water wells, centralized ponds, and a buried distribution network allowing water to be sent to fracture locations throughout our leasehold interests in the Sugarkane area; and
- gas lift capability and distribution network to sustain production once wells no longer flow via natural reservoir energy.

During 2016, production from the United States Business Unit averaged approximately 28,046 bbl/d of tight oil and NGL and 51,167 Mcf/d of shale gas (36,573 boe/d). During this period, Baytex participated in the drilling of 127 (36.9 net) wells in the Sugarkane area, resulting in 43 (12.8 net) oil wells and 84 (24.1 net) natural gas wells for a success rate of 100%.

Average Production

The following table indicates our average daily production from our principal properties for the year ended December 31, 2016.

	Heavy Oil (bbl/d)	Bitumen (bbl/d)	Light and Medium Oil (bbl/d)	Tight Oil (bbl/d)	NGL (bbl/d)	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Lloydminster Business Unit								
Cold Lake / Ardmore	608	—	—	—	—	—	365	669
Soda Lake	2,095	—	—	—	—	—	108	2,113
Celtic	1,377	—	—	—	—	—	—	1,377
Kerrobert / Hoosier	858	1,544	5	—	—	—	20	2,410
Tangleflags	1,858	—	—	—	—	—	464	1,935
Remaining properties	1,595		—	—	—	—	425	1,666
Total	8,391	1,544	5	—	—	—	1,382	10,170
Peace River Business Unit	13,651	—	—	—	—	—	4,180	14,348
Conventional Business Unit								
Pembina	—	—	186	—	1,181		26,799	5,834
Remaining properties	—	—	1,216	—	93	—	7,654	2,585
Total	—	—	1,402	—	1,274	—	34,453	8,419
United States Business Unit								
Sugarkane (non-operated)	—	—	—	19,497	8,013	50,720	—	35,963
Sugarkane (operated)[1]	—	—	—	473	62	447	—	610
Total	—	—	—	19,970	8,075	51,167	—	36,573
Grand Total	22,042	1,544	1,407	19,970	9,349	51,167	40,015	69,510

Note:

(1) This property was sold in July of 2016.

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2016:

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	54	—	54
Unproved properties	102	—	102
Property disposition	(9,039)	(54,237)	(63,276)
Total Property acquisition costs, net	(8,883)	(54,237)	(63,120)
Development Costs[1]	21,184	198,910	220,094
Exploration Costs[2]	4,689	—	4,689
Total	16,990	144,673	161,663

Notes:

(1) Development and facilities expenditures.
(2) Cost of geological and geophysical capital expenditures and drilling costs for 2016 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, 2016.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	855	566.1	1,037	590.4	354	276.8	496	387.6
Saskatchewan	577	559.8	1,374	1,312.0	16	13.2	128	115.2
Texas	550	126.0	19	3.9	320	87.0	43	13.0
Total	1,982	1,251.9	2,430	1,906.3	690	377.0	667	515.8

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2016.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	554,178	489,669
Saskatchewan	119,004	113,439
Total Canada	673,182	603,108
United States		
Texas (Eagle Ford)	654	208
Texas (East Texas)	2,384	2,327
Total United States	3,038	2,535
Grand Total	676,220	605,643

We estimate the value of our net undeveloped land holdings at December 31, 2016 to be approximately $67.1 million, as compared to $110.3 million at December 31, 2015. 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 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 12,655 net acres of our undeveloped land holdings (comprised of 1,474 net acres in the United States and 11,181 net acres in Canada) will expire on or before December 31, 2017. There are no reserves associated with the land holdings expected to expire by December 31, 2017. None of these undeveloped properties have high expected development or operating costs or contractual sales obligations to produce and sell at substantially lower prices than could be realized.

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, 2016.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	57	15.8	57 15.78	15.8
Natural Gas	—	—	85	25.1	85	25.1
Evaluation	—	—	—	—	—	—
Service	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	—	—	142	40.9	142	40.9

Tax Horizon

Baytex does not expect to pay any material cash income taxes prior to 2020. This estimate and any amount of income tax we may be required to pay in the future is highly sensitive to assumptions regarding commodity prices, production, funds from operations, capital expenditure levels and changes in governing tax laws. For additional information, see Note 15 of our audited consolidated financial statements for the year ended December 31, 2016 and the information under the headings "*Income Taxes*" and "*Tax Pools*" in our MD&A for the year ended December 31, 2016.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2016, 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)	Tight Oil (bbl/d)	NGL (bbl/d)	Shale Gas (Mcf/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA								
Total Proved	18,971	734	996	—	1,033	—	33,132	27,257
Total Proved plus Probable	20,462	879	1,083	—	1,274	—	38,678	30,144
UNITED STATES								
Total Proved	—	—	—	10,566	17,752	36,708	13,816	36,739
Total Proved plus Probable	—	—	—	11,325	20,819	41,951	14,539	41,559
TOTAL								
Total Proved	18,971	734	996	10,566	18,786	36,708	46,948	63,996
Total Proved plus Probable	20,462	879	1,083	11,325	22,093	41,951	53,217	71,703

The two properties that account for 20% or more of the estimated 2017 production volumes are the Eagle Ford and Peace River (cold primary production). Estimated 2017 production volumes for Eagle Ford are 36,739 boe/d on a total proved basis and 41,559 boe/d on a total proved plus probable basis. Estimated 2017 production volumes for Peace River (cold primary production) are 13,327 boe/d on a total proved basis and 13,878 boe/d on a total proved plus probable basis.

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, 2016	Sept 30, 2016	June 30, 2016	Mar. 31, 2016	Dec. 31, 2016
Average Sales Volume[1]					
Heavy Oil (bbl/d)	21,696	22,663	20,768	23,040	22,042
Bitumen (bbl/d)	1,286	1,469	1,655	1,767	1,544
Light Oil (bbl/d)	1,281	1,321	1,461	1,566	1,406
NGL (bbl/d)	8,319	9,149	9,834	10,109	9,349
Tight Oil (bbl/d)	18,882	17,680	20,433	22,923	19,970
Shale Gas (Mcf/d)	45,228	47,468	55,859	56,217	51,167
Natural Gas (Mcf/d)	36,804	41,846	39,422	42,003	40,015
Total (boe/d)	65,136	67,167	70,031	75,776	69,509
Average Net Production Prices Received					
Heavy Oil ($/bbl)	34.19	29.65	30.00	12.55	26.41
Bitumen ($/bbl)	36.80	31.90	31.19	12.46	27.20
Light Oil ($/bbl)	55.16	48.51	47.24	35.89	46.21
NGL ($/bbl)	22.64	14.96	13.28	18.38	17.16
Tight Oil ($/bbl)	60.45	53.60	52.79	38.11	50.60
Shale Gas ($/Mcf)	4.28	3.70	2.39	2.76	3.21
Natural Gas ($/Mcf)	2.78	2.11	1.30	1.91	2.01
Total ($/boe)	38.16	31.73	30.52	21.93	30.29

Royalties Paid					
Heavy Oil ($/bbl)	6.51	5.05	3.44	1.10	4.01
Bitumen ($/bbl)	2.54	2.20	0.78	0.59	1.43
Light Oil and NGL ($/bbl) [2]	4.48	3.99	4.69	4.10	4.32
Tight Oil ($/bbl)	14.53	11.61	11.21	8.84	11.41
Shale Gas ($/Mcf)	1.67	1.43	0.96	1.03	1.24
Natural Gas ($/Mcf)	(0.13)	0.02	0.02	0.09	—
Total ($/boe)	9.28	7.37	6.65	5.02	7.00
Operating Expenses [3]					
Heavy Oil ($/bbl)	13.42	12.40	10.60	11.02	11.87
Bitumen ($/bbl)	18.53	16.83	14.59	14.70	15.98
Light Oil and NGL ($/bbl) [2]	11.57	11.59	10.80	10.27	11.04
Tight Oil ($/bbl) [4]	6.98	5.82	6.88	9.38	7.36
Shale Gas ($/Mcf) [4]	1.16	0.97	1.15	1.56	1.23
Natural Gas ($/Mcf)	1.91	1.90	1.77	1.69	1.82
Total ($/boe)	9.96	9.07	8.67	10.11	9.46

	Three Months Ended				Year Ended
	Dec. 31, 2016	**Sept 30, 2016**	**June 30, 2016**	**Mar. 31, 2016**	**Dec. 31, 2016**
Transportation Expenses					
Heavy Oil ($/bbl)	3.27	3.43	2.02	2.64	2.86
Bitumen ($/bbl)	1.49	1.73	1.72	0.24	1.25
Light Oil and NGL ($/bbl) [2]	1.11	1.08	1.19	1.18	1.14
Tight Oil ($/bbl) [4]	—	—	—	—	—
Shale Gas ($/Mcf) [4]	—	—	—	—	—
Natural Gas ($/Mcf)	1.47	1.41	1.29	1.38	1.39
Total ($/boe)	1.30	1.38	0.81	0.98	1.11
Netback Received [5]					
Heavy Oil ($/bbl)	10.99	8.77	13.94	(2.21)	7.67
Bitumen ($/bbl)	14.24	11.14	14.10	(3.07)	8.54
Light Oil and NGL ($/bbl) [2]	19.49	16.97	17.24	11.60	16.19
Tight Oil ($/bbl)	38.94	36.17	34.70	19.89	31.83
Shale Gas ($/Mcf)	1.45	1.30	0.28	0.17	0.74
Natural Gas ($/Mcf)	(0.47)	(1.22)	(1.78)	(1.25)	(1.20)
Total ($/boe)	17.62	13.91	14.39	5.82	12.72
Other income ($/boe)	—	—	—	—	—
Financial Derivatives gain (loss) ($/boe)	1.62	3.04	3.74	6.47	3.81
Netback Received after hedging ($/boe)	19.24	16.95	18.13	12.29	16.53

Notes:
(1) Before deduction of royalties.
(2) All NGL volumes are grouped with Canadian light oil 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 NGL production.
(4) Transportation expenses split for costs between tight oil and shale gas are not available for Eagle Ford.
(5) Netback is calculated by subtracting royalties, operating expenses and transportation expenses from revenues.

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.

Oil and NGL

For the year ended December 31, 2016, the prompt price settlements of West Texas Intermediate crude oil fluctuated from a low of US$26.21/bbl in February to a high of US$54.06/bbl in late December, with an average price of US$43.33/bbl. The volatile price range seen in 2016 was driven by an ongoing global overhang of crude oil and petroleum product inventories as OPEC continued to favor a market share strategy for the majority of the year before coming to a new production quota agreement on November 30, 2016.

The discount for Canadian heavy oil, as measured by the Western Canadian Select (" **WCS**") price differential to WTI, averaged 32% for the year ended December 31, 2016, as compared to an average of 28% for the year ended December 31, 2015. The WCS nominal differential averaged US$13.84/bbl in 2016 as compared to US$13.52 in 2015.

For 2016, Baytex's heavy oil sales prices averaged $26.46/bbl, while light oil and condensate prices averaged $50.32/ bbl. In contrast, for 2015 Baytex averaged $32.23/bbl for heavy oil sales and $55.75/bbl for light oil and condensate sales. Baytex's NGL price in 2016 was $17.16/bbl, as compared with $16.91/bbl in 2015. In 2016, Baytex's U.S. light oil and condensate price realizations averaged $50.60/bbl, as compared to $55.99/bbl in 2015, as the average annual price for the WTI benchmark decreased by 11% from US$48.79/bbl in 2015 to US$43.33/bbl in 2016.

Natural Gas

For the year ended December 31, 2016, the average AECO natural gas price was $2.09/Mcf, as compared to $2.74/Mcf in the same period of 2015. The decrease in the natural gas price was due to high natural gas production growth in Canada and the U.S. For 2016, Baytex's average realized natural gas sales price was $2.69/Mcf, as compared to $3.08/Mcf in 2015.

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2016, see Note 18 to our audited consolidated financial statements for the year ended December 31, 2016.

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, 2016, 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(1) Calgary, Alberta	56	Director and Chief Executive Officer	Chief Executive Officer of Baytex
John A. Brussa (4) (5) Calgary, Alberta	59	Director	Vice Chairman of Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	61	Director and Chairman of the Board	Chairman of the Board of Baytex
Edward Chwyl (3) (4) Victoria, B.C.	73	Director	Independent Businessman
Trudy M. Curran(2) (5) Calgary, Alberta	54	Director	Corporate Director
Naveen Dargan (2) (3) Calgary, Alberta	59	Director	Independent Businessman
R.E.T. (Rusty) Goepel (5) Vancouver, B.C.	74	Director	Senior Vice President of Raymond James Ltd.
Gregory K. Melchin (2)(5) Calgary, Alberta	63	Director	Independent Businessman
Mary Ellen Peters (2) (3) Sarasota, Florida	60	Director	Independent Businesswoman
Dale O. Shwed (4) Calgary, Alberta	58	Director	President and Chief Executive Officer of Crew Energy Inc.
Kendall D. Arthur(7) Calgary, Alberta	36	Vice President, Lloydminster and Conventional Business Units	Vice President, Lloydminster and Conventional Business Units of Baytex
Geoffrey J. Darcy Calgary, Alberta	54	Senior Vice President, Marketing	Senior Vice President, Marketing of Baytex
Murray J. Desrosiers Calgary, Alberta	47	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary of Baytex
Brian G. Ector Calgary, Alberta	48	Senior Vice President, Capital Markets and Public Affairs	Senior Vice President, Capital Markets and Public Affairs of Baytex
Rodney D. Gray Calgary, Alberta	45	Chief Financial Officer	Chief Financial Officer of Baytex
Cameron A. Hercus Calgary, Alberta	47	Vice President, Corporate Development	Vice President, Corporate Development of Baytex
Ryan M. Johnson(7) Calgary, Alberta	40	Vice President, Peace River Business Unit	Vice President, Peace River Business Unit of Baytex

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
Chad L. Kalmakoff Calgary, Alberta	40	Vice President, Finance	Vice President, Finance of Baytex
Edward D. LaFehr(1) Calgary, Alberta	57	President	President of Baytex
Richard P. Ramsay Calgary, Alberta	53	Chief Operating Officer	Chief Operating Officer of Baytex
Gregory A. Sawchenko Calgary, Alberta	44	Vice President, Land	Vice President, Land of Baytex
Gregory M. Zimmerman Houston, Texas	58	Vice President, U.S. Business Unit	Vice President, U.S. Business Unit of Baytex

Notes:

(1) On December 12, 2016, the Corporation announced that effective May 2017 James L. Bowzer will resign as Chief Executive Office and be succeeded by Edward D. LaFehr.

(2) Member of our Audit Committee.

(3) Member of our Compensation Committee.

(4) Member of our Reserves Committee.

(5) Member of our Nominating and Governance Committee.

(6) 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).

(7) Effective January 20, 2017, Kendall D. Arthur was given responsibility for the Conventional Business Unit which had previously been the responsibility of Ryan M. Johnson and Mr. Arthur's title was changed to Vice President, Lloydminster and Conventional Business Units and Mr. Johnson's title was changed to Vice President, Peace River Business Unit.

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 has served as Chief Executive Officer and as a director of Baytex since September 4, 2012. He also served as President from September 2012 to July 2016. 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.

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 held the same position with Baytex Energy from February 17, 2009 to December 19, 2014. 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.

Trudy M. Curran became a Director of Baytex on July 27, 2016 and is a retired businesswoman with extensive experience in executive compensation, mergers and acquisitions, financing and governance. She served as an officer of Canadian Oil Sands Limited from September 2002 to the time of its sale in February 2016. As Senior Vice President, General Counsel & Corporate Secretary of Canadian Oil Sands Limited, she was responsible for legal, human resources and administration and a member of the executive team focused on strategy and risk management. From 2003 to 2016, she was a director of Syncrude Canada Ltd., where she served as chair of the Human Resources and Compensation Committee and as a member of the Pension Committee. Ms. Curran is a director of Dominion Diamond Corporation and serves on the Executive Committee of the Calgary chapter of the Institute of Corporate Directors and is a member of the board and the Finance and Audit Committee of Kids Cancer Care Foundation of Alberta. Ms.Curran holds a Bachelor of Arts degree in English and a Bachelor of Laws degree (both with distinction) from the University of Saskatchewan and the ICD.D designation from the Institute of Corporate Directors.

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. 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 March 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 on July 1, 2013. She is a 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. Prior thereto, she held various technical and management positions with Marathon. Her 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. 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

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 and became Vice President, Lloydminster and Conventional Business Units on February 20, 2017. 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 position with Baytex Energy since May 20, 2009. Mr. Desrosiers is a corporate lawyer with over 20 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 (November 2009 to June 2011), Vice President, Investor Relations (June 2011 to March 2014) and Vice President, Capital Markets (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 20 years of 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.

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 (Honours) 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, Peace River Business Unit of Baytex on February 20, 2017. Mr. Johnson joined Baytex in 2007 focusing on technical responsibilities in northeast Alberta and southern Saskatchewan, including the planning and execution of Baytex's 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.

Chad L. Kalmakoff was appointed Vice President, Finance of Baytex on September 1, 2015. Mr. Kalmakoff has 15 years of experience in the oil and gas industry. Prior to joining Baytex, Mr. Kalmakoff was Vice President, Finance and Chief Financial Officer at Kicking Horse Energy Inc. from October 2014 to August 2015. From October 2013 to July 2014, he was Vice President, Finance and Chief Financial Officer at Corinthian Exploration Ltd. Prior thereto, he was Chief Financial Officer (March 2012 to March 2013) and Vice President, Finance (June 2006 to March 2012) at Pace Oil & Gas Ltd. and its predecessor, Midnight Oil Exploration Ltd. Mr. Kalmakoff is a Chartered Accountant and holds a Bachelor of Commerce from Dalhousie University.

Edward D. LaFehr joined Baytex as President on July 18, 2016 and has been an integral member of the executive leadership team holding responsibility for the Canadian and U.S. business operations and corporate development. Mr. LaFehr will succeed Mr. Bowzer as Chief Executive Officer upon his expected retirement in May 2017. Mr. LaFehr has nearly 35 years of experience in the oil and gas industry working with Amoco, BP, Talisman and the Abu Dhabi National Energy Company ("TAQA") in various geographies. Before joining Baytex, Mr. LaFehr was President of TAQA's North American oil and gas business which led to his subsequent role as Chief Operating Officer of TAQA, globally. Prior to this, he served as Senior Vice President for Talisman Energy, accountable for its Canadian business. Mr. LaFehr has a long track record of success in the oil and gas industry leading organizations, growing assets and joint ventures and driving capital and cost efficiencies. Mr. LaFehr holds Master's degrees in geophysics and mineral economics from Stanford University and the Colorado School of Mines, respectively.

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 (January 2010 to January 2012) and Vice President, Alberta/B.C. Business Unit (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 and Geoscientists 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.

Gregory M. Zimmerman was appointed Vice President, U.S. Business Unit of Baytex on November 16, 2015. 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. Mr. Zimmerman has over 30 years of experience in the oil and gas industry all with Marathon Oil Corporation. At Marathon, he held a number of positions of increasing responsibility in production, operations, reservoir and business development. His most recent positions included Director of Corporate Reserves in Houston, Texas and Vice President, Oil Sands Development in Calgary, Alberta. His primary area of focus over the last 20 years of his career with Marathon has been asset management, reservoir development and project execution. Mr. Zimmerman has a Bachelor of Science degree in Mechanical Engineering from Texas A&I University.

Ownership of Securities by Management

As at March 1, 2017, the directors and officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 3,362,038 Common Shares, representing approximately 1.436 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, Enseco Energy Service Corp. (a public oilfield equipment supplier) which was placed in receivership on October 14, 2015, Argent Energy Ltd., the administrator of Argent Energy Trust (a public trust holding investments in oil and gas exploration and production companies) which received protection from its creditors pursuant the Companies' Creditors Arrangement Act in Canada and Chapter 15 of the United States Bankruptcy Code on March 19, 2016 and Twin Butte Energy Ltd. (a public oil and gas exploration and production company) which was placed in receivership on September 1, 2016. Mr. Brussa resigned as a director of Calmena on June 30, 2014, Enseco on October 14, 2015, Argent on June 30, 2016 and Twin Butte on September 1, 2016.

Mr. Dargan, a director of Baytex, was formerly a director of Tervita Corporation (a private environmental solutions company). Tervita made a proposal under the *Canada Business Corporations Act* on September 14, 2016 and a voluntary filing under Chapter 15 of the United States Bankruptcy Code on October 20, 2016, which resulted in a plan of arrangement under the *Canada Business Corporations Act*. Mr. Dargan resigned as a director of Tervita on December 13, 2016.

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 or with entities which may, from time to time, provide financing to, or make equity investments in, competitors of Baytex. 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 D.

Composition of the Audit Committee

The members of our Audit Committee are Trudy M. Curran, 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
Trudy M. Curran	Yes	Yes	Bachelor of Arts degree in English and a Bachelor of Laws degree (both with distinction) from the University of Saskatchewan and the ICD.D designation from the Institute of Corporate Directors. Independent businesswoman since February 2016; prior thereto, Senior Vice President, General Counsel and Corporate Secretary of Canadian Oil Sands Limited since September 2002.
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 MD&A 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 our external auditors, during fiscal 2016 and 2015:

	Aggregate fees billed ($000s)	
	2016	**2015**
Audit Fees	$ 662	$ 1,018
Audit-Related Fees	115	201
Tax Fees	13	-
All Other Fees	-	-
Total	$ 790	$ 1,219

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 2016 and 2015 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.

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 (including fees paid to the Canadian Public Accountability Board) and are not reported as Audit Fees. Audit-related fees also include reviews of prospectuses related to two public offerings of common shares, one in 2016 and the other in 2015.

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

DIVIDENDS

Dividend Policy

We do not currently pay a dividend and do not currently have any plans to resume the payment of cash dividends. Any dividends declared in the future will be subject to review by the Board of Directors taking into account our prevailing financial circumstances at the relevant time and any amount distributed in the future 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.

In addition, the payment of dividends by us 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. 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 our ability to fulfill our 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 restricted payments. Restricted payments include the declaration or payment of any dividend or distribution by us. For full particulars of the covenants, reference should be made to the indentures governing our Senior Notes and to our Credit Facilities, copies of which are accessible on the SEDAR website, see "*Material Contracts*" for further details.

Record of Dividends and Distributions

We did not pay any dividends in 2016. In 2015, we paid a monthly dividend on our Common Shares of $0.10 from January until August, for an aggregate dividend per Common Share of $0.80. In 2014, we paid a monthly dividend on our Common Shares of $0.22 from January until May, $0.24 from June until November and $0.10 for December, for an aggregate dividend per Common Share of $2.64. Unless otherwise indicated, all dividends paid on our Common Shares were designated as "eligible dividends" for Canadian income tax purposes.

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 at 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 seven 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

Our Credit Facilities consist of: (i) a US$25 million operating loan and a US$350 million syndicated loan for Baytex and (ii) a US$200 million syndicated loan for Baytex USA. The Credit Facilities are secured and have an extendible four-year term that, unless extended by the lenders, will mature on June 4, 2019. For additional details regarding the covenants in our Credit Facilities and our compliance therewith, see our MD&A for the year ended December 31, 2016. Also see *"Material Contracts"*.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX and the NYSE under the trading symbol "BTE". The following table outlines the share price trading range and volume of shares traded by month in 2016.

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
2016						
January	4.75	1.57	242,626,409	3.42	1.08	50,460,811
February	3.19	2.21	205,306,028	2.35	1.59	36,854,592
March	5.39	3.03	321,616,827	4.15	2.24	66,736,803
April	6.80	4.84	239,995,241	5.41	3.67	56,168,254
May	6.50	5.71	213,423,776	5.12	4.42	58,435,698
June	9.04	6.15	268,665,034	7.14	4.68	83,910,507
July	7.72	5.57	180,268,166	6.18	4.25	55,682,798
August	7.24	5.52	208,458,282	5.64	4.19	55,119,223
September	6.37	4.76	222,134,067	4.95	4.70	58,181,674
October	6.09	5.12	175,777,649	4.61	3.81	46,036,356
November	5.80	4.84	220,330,400	4.33	3.60	70,199,063
December	7.35	5.78	195,005,636	5.61	4.35	70,187,329

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 our contracts, and (ii) enter into and maintain ordinary course contracts with customers and suppliers on acceptable terms.

Baytex has been assigned a corporate credit rating of BB- with a negative 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).

Moody's Investor Service Inc. ("**Moody's**") has assigned Baytex a corporate family credit rating of Caa1, assigned our Senior Notes a credit rating of Caa1 and stated that our rating outlook is negative. 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 "Caa" are rated as being poor quality and a very high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from Aa through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category. 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 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

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (CRA) that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments follow the previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

We have filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of the CRA; a process that we estimate could take up to two years. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (Losses). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available for “carry back” to the years 2012 through 2015.

Other than the foregoing, 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 within the three most recently completed financial years 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 was our auditor until their resignation on June 23, 2016, at which time they were replaced by KPMG LLP. Both are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

Computershare Trust Company of Canada, 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. Computershare Trust Company, N.A., at its principal office in Canton, Massachusetts, is the transfer agent and registrar for the Common Shares in the United States, 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 "Continuous Disclosure Obligations" by us during, or related to, our most recently completed financial year other than Sproule and Ryder Scott, our independent qualified reserves evaluators. None of the designated professionals of Sproule or Ryder Scott 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 April 13, 2016);

(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 April 18, 2016).

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. On December 21, 2015, the Government of the United States repealed its ban on crude oil exports to the international market.

Natural Gas

In Canada and the United States, producers of natural gas are entitled to negotiate sales contracts directly with 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. The Government of Alberta recently announced that it would be implementing a new royalty regime applicable to production from wells drilled after 2017 and, as of January 1, 2027, to wells drilled during or prior to 2017. The new royalty structure is to have three phases: pre-payout, mid-life and mature, with a higher royalty rate applicable during the mid-life phase. Details of the new royalty regime are expected to be released by March 31, 2016.

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 are 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

The Provinces of Alberta, British Columbia and Saskatchewan have each 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 Railroad Commission of Texas ("**RRC**"). 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 set 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. 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.

In the United States, occupational safety and health, environmental conservation, cultural and natural resources protection are administered by numerous agencies under multiple statutes, as amended from time to time. The environmental and occupational health and safety agencies that most significantly affect our operations include the

Federal Occupational Safety and Health Administration ("**OSHA**"), Federal Environmental Protection Agency ("**EPA**"), Texas Commission on Environmental Quality ("**TCEQ**") and RRC.

The OSHA regulates working conditions by setting and enforcing safety and health standards through multiple federal Acts of Congress, most notably the Occupational Safety and Health Act of 1970. OSHA frequently amends/updates regulations, and has recently increased its attention given to the oil and gas industry. For example, OSHA issued a proposed rule on September 12, 2013 to enforce stricter standards to prevent worker exposure to crystalline silica, particularly during hydraulic fracturing. This rule is expected to be formally issued sometime in 2016. Additionally, on December 9, 2013, OSHA began to enhance the regulation and enforcement of oil and gas operations under its Process Safety Management Standard by issuing a series of memoranda, requests for information, and guidance documents to the public. The EPA regulates activities that could affect human health and the environment. It derives its authority from a long list of Acts of Congress, including the Clean Water Act, the Clean Air Act, the Oil Pollution Act of 1990, the Comprehensive Environmental Response, Compensation and Liability Act of 1980 and the Resource Conservation and Recovery Act. The EPA establishes and strictly enforces standards for environmental pollution. In the recent past, the EPA exempted much of the oil and gas industry from its regulations. However, over the past several years, the EPA's focus has shifted, resulting in a rapid increase in regulation for the industry, especially regarding pollutive air emissions, and including previously unregulated greenhouse gasses. At the state level in Texas, the TCEQ regulates public health and natural resources including air, water and waste and the RCC regulates the stewardship of oil and natural gas resources, along with some aspects of environmental protection and safety related to extraction of those resources. In a similar manner to the efforts of the EPA mentioned above, the TCEQ has recently increased its regulation and enforcement relating to the oil and gas industry, especially regarding air emissions. The RRC regulations establish environmental remediation and reporting criteria for cleanup of oil and produced water spills.

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 GHG emissions. Both governments agreed to an economy-wide target of a 17% reduction of GHG emissions from 2005 levels. Both governments also signed the Paris Agreement in December of 2015, which included a commitment to keep any increase in global temperatures below two degrees Celsius. Additionally, Canada pledged to reduce GHG emissions by 30% by 2030 from 2005 levels and the United States pledged to reduce GHG emissions by 26% to 28% by 2025 from 2005 levels.

The United States has not yet announced or enacted any mechanisms or legislation to implement the Paris Agreement. The Government of Canada has announced that it intends to implement a carbon tax in 2018 starting at $10/tonne rising by $10/tonne a year to $50/tonne by 2022. This federal carbon tax is intended to be implemented in concert with the Provinces and territories and would only be implemented in those Provinces and territories that do not have their own carbon tax.

The Province of Alberta announced and implemented a broad range of plans targeting GHG emissions, that include: a carbon levy of $20/tonne that became effective January 1, 2017 that will increase to $30/tonne in 2018, a cap on GHG emissions from the oil sands of 100 Mt per year and a plan to introduce regulations that will reduce methane emissions from oil and gas operations by 45% by 2025. 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.

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, 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 our website and on the SEDAR website at *www.sedar.com*. Further 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 4, 2017. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2016 and the related MD&A which are accessible on the SEDAR website at *www.sedar.com*.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

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APPENDIX A

CONTINGENT RESOURCE ESTIMATES

We commissioned Sproule to conduct an evaluation of our contingent resources in Lloydminster, Peace River, Northeast Alberta and Pembina in Canada. We commissioned Ryder Scott to audit our internal evaluation of our contingent resources in the Eagle Ford area of Texas. Both assessments were effective December 31, 2016, prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and based on the Sproule December 31, 2016 forecast prices and costs set forth under "*Statement of Reserves Data and Other Oil and Gas Information - Forecast Prices and Costs*" in the body of this Annual Information Form.

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. There is no certainty that it will be commercially viable to produce any portion of our contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The recovery and resource estimates provided 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.

The contingent resources described below represent our gross interests (unless otherwise indicated) and are a best estimate. A "best estimate" is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual quantities recovered will be greater or less than the best estimate. Those resources identified in the best estimate have a 50% probability that the actual quantities recovered will equal or exceed the estimate. The contingent resources herein are presented as deterministic cumulative best estimate volumes.

Contingent resources should not be confused with reserves and readers should review the definitions and notes set forth herein. Actual crude oil, natural gas, and natural gas liquids resources may be greater than or less than the estimates provided. There is uncertainty that it will be commercially viable to produce any portion of the resources.

Our contingent resources fall within the development pending and development unclarified sub-classes, which are defined as follows:

- **Development Pending** - are economic contingent resources that have a high chance of development. Contingencies are directly influenced by the developer, are actively being pursued and resolution is expected in a reasonable time period.
- **Development Unclarified** - are contingent resources that have a chance of development which is difficult to assess, and have an economic status which is undetermined. Projects are currently under evaluation and therefore contingencies are not clearly defined. Progress is expected within a reasonable time period.

Projects for which Resources are Being Attributed

Development Pending Project Maturity Sub-Class

Summary of Risked Petroleum and Natural Gas Contingent Resources as of December 31, 2016 Forecast Prices and Costs [(1)]

Heavy Crude Oil		Bitumen		Light & Medium Crude		Conventional Natural Gas	
Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)
5,202	4,695	15,715	12,529	15	11	8,963	7,407

Tight Oil		Natural Gas Liquids		Shale Gas		Oil Equivalent	
Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mboe)	Net (Mboe)
7,345	5,419	2,571	1,896	10,321	7,585	34,061	27,049

Note:
(1) Based on the reports prepared by Sproule and Ryder Scott effective December 31, 2016.

Summary of Risked Net Present Value of Future Net Revenue (Contingent Resources) as of December 31, 2016 Forecast Prices and Costs [(1)(2)]

($ millions)	Before Income Taxes Discounted at (% / year)					After Income Taxes Discounted at (% / year)				
Resources Project Maturity Sub-Class	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
Development Pending	768	392	211	116	64	517	260	135	70	34

Notes:
(1) An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized.
(2) Based on the reports prepared by Sproule and Ryder Scott effective December 31, 2016.

The following table summarizes the status of our development pending contingent resources.

Development Pending - Project Status

Area	Product Type	Project Status	Future Development Costs ($ millions)[(1)]	Timing of First Commercial Production	Recovery Technology
Peace River	Bitumen	Development Study	$129	2019-2021	Cyclic steam stimulation
Peace River, Lloydminster and North East Alberta	Heavy Oil	Development Study	$94	2017-2023	Horizontal, vertical and multilateral well development
Pembina	Light & Medium Oil, Natural Gas	Development Study	$13	2,022	Horizontal well development with multi-stage fracturing completion
Eagle Ford	Tight Oil, Shale Gas and NGL	Pre-Development	$152	2017-2028	Horizontal well development with multi-stage fracturing completion

Note:
(1) Undiscounted and unrisked.

The following table presents a summary of the quantitative risk of the chance of development we have applied to our development pending contingent resources.

Development Pending - Chance of Development Risk [1]

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)	Risked NPV [2] Discounted at 10% (before tax) ($ millions)
Peace River	Bitumen	19	81%	16	70
Peace River, Lloydminster and North East Alberta	Heavy Oil	6	86%	5	23
Pembina	Light & Medium Oil, Natural Gas	2	90%	2	11
Eagle Ford	Tight Oil, Shale Gas and NGL	14	80%	11	107
Total		41		34	211

Notes:
(1) Numbers may not add due to rounding.
(2) An estimate of risked net present value of future net revenue of contingent resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of the company proceeding with the required investment. It includes contingent resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is no certainty that the estimate of risked net present value of future net revenue will be realized.

The development pending contingent resources attributed to the Peace River area consist of bitumen volumes allocated to the CSS project at Cliffdale in the Bluesky formation. Using the volumetric data obtained from a geological review, an estimation of the original-bitumen-in-place (OBIP) was calculated. The recovery was estimated based on the performance of our Cliffdale CSS project in the area. CSS is an established technology, which involves injecting steam into a well and then producing heated bitumen and water from the same well bore. Alternating injection and production cycles are repeated a number of times unique to each well bore until economics are no longer justified.

Heavy oil development pending contingent resources in the Lloydminster and Northeast Alberta areas represent the horizontal and vertical well development of the Lower Cretaceous Mannville Group using cold production recovery methods. Heavy oil development pending contingent resources in the Peace River Area represent the horizontal, multi-lateral development of the Bluesky Formation using cold production recovery methods, similar to the development of our existing reserves. These contingent resources volumes were evaluated deterministically by analogy to producing wells utilizing decline analysis to create an expected type well recoverable volume. The expected type well recoverable volume was then compared to an estimated original-oil-in-place (OOIP) to estimate a recovery factor. All areas have analogous wells or reservoirs which employ the same recovery methods and these recovery methods are considered to be established technologies.

The development pending contingent resources in the Pembina Area are attributed to the Falher, Notikewan, Wilrich, Cardium and commingled (Cardium, Viking, Mannville, Rock Creek) formations. These volumes were estimated deterministically based on volumetric analysis and by performance of analogous offsetting wells and are expected to be developed will horizontal wells and multi-stage fracturing completions. Contingent resources for the vertical commingled wells are based on a statistical analysis of offsetting analogous wells. These development technologies are similar to those we are using to develop our existing reserves.

The development pending contingent resources in the Eagle Ford area consist of tight oil, shale gas and natural gas liquids from the Lower Eagle Ford, Upper Eagle Ford, Upper/Lower Eagle Ford and Austin chalk zones. These contingent resources were evaluated internally and were independently audited by Ryder Scott. These volumes are expected to be developed utilizing horizontal wells and multi-stage fracturing completions, similar to the development

of our existing reserves. These contingent resources volumes were estimated deterministically by analogy to producing wells using decline analysis.

Development Unclarified Project Maturity Sub-Class

Our development unclarified contingent resources are conceptual project scenarios with no specific company defined development plan in the near-term. The following table presents a summary of the quantitative risk of the chance of development we have applied to our development unclarified contingent resources.

Development Unclarified - Chance of Development Risk *(1)*

Area	Product Type	Unrisked (MMboe)	Chance of Development	Risked (MMboe)
Peace River and North East Alberta	Bitumen	943	58%	551
Peace River, Lloydminster and North East Alberta	Heavy Oil	29	56%	16
Pembina	Light & Medium Oil, Natural Gas	12	55%	7
Eagle Ford	Tight Oil, Shale Gas and NGL	120	50%	60
Total		1,103		634

Note:
(1) Numbers may not add due to rounding.

Development unclarified contingent resources have been attributed to bitumen volumes in place in the greater Peace River area. They include projects to expand our Cliffdale project with further horizontal CSS development and several smaller vertical and horizontal CSS projects and a SAGD project.

Development unclarified contingent resources have also been assigned to bitumen volumes in the Northeast Alberta area that are expected to be recovered through thermal recovery projects including a vertical CSS project, a SAGD project and an expansion of the Gemini SAGD project. Using volumetric data obtained from a geological review, an estimation of the OBIP was calculated. Different recovery factors were determined to account for reservoir complications such as the presence of bottom water and/or shale intervals.

Development unclarified contingent resources in the Lloydminster and Northeast Alberta areas have been assigned to heavy oil volumes which are expected to be recovered through horizontal and vertical well development and produced using cold production methods. All areas have analogous wells or reservoirs which employ the same recovery methods which are considered to be established technologies.

The development unclarified contingent resources volumes in the Eagle Ford area are associated with further development of the Austin Chalk and Upper Eagle Ford zones. These are expected to be developed utilizing horizontal well completions.

Chance of Discovery and Development Risk

The principal risks that would influence the development of the Lloydminster, Northeast Alberta, Peace River and Pembina development pending contingent resources are: the timing of regulatory approvals to expand the project areas; the results of delineation drilling and seismic activity necessary for project development; the ability of these projects to compete for capital against our other projects; our corporate commitment to the timing of development; and the

commodity price levels affecting the economic viability bitumen and heavy oil production in Alberta. The principal risks specific to the development of the Eagle Ford development pending contingent resources are: our reliance on the operator's capital commitment and development timing; the ability of these projects to compete for capital against our other projects; and the possibility of inter-well communication from infill drilling.

In addition to the risks identified for the development pending sub-class, the projects in the Lloydminster, Northeast Alberta, Peace River and Pembina areas development unclarified sub-class are also subject to risks pertaining to commercial productivity of the reservoirs. The geological complexity and variability in these reservoirs may require the implementation of pilot projects to test the viability of CSS and SAGD recovery technologies. The risks outlined for the contingent resources in the Eagle Ford development pending sub-class also apply to the development unclarified sub-class but are greater in magnitude.

Contingencies

Continuous development through multi-year exploration and development programs and significant levels of future capital expenditures are required in order for contingent resources to be recovered in the future. 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.

For more information, see " *Risk Factors*" in the Annual Information Form to which this Appendix A is attached.

APPENDIX B

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 and other information such as contingent resources data.

Independent qualified reserves evaluators have evaluated Baytex's reserves data and have evaluated and audited Baytex's contingent resources data. The report of the independent qualified reserves evaluators 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 evaluators;

b. met with the independent qualified reserves evaluators to determine whether any restrictions affected the ability of the independent qualified reserves evaluators 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, contingent resources data and other oil and gas information;

b. the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluators on the reserves data; and

c. the content and filing of this report.

Because the reserves data and contingent resources 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
Chief Executive Officer

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

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

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

March 7, 2017

APPENDIX C

REPORT ON RESERVES DATA AND CONTINGENT RESOURCES 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 and contingent resources data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended form time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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 and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. 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, 2016, 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, 2016). Prepared: August 2016 to February 2017	Canada	Nil	$1,548,399	Nil	$1,548,399

6. The following table sets forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in Baytex's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the management and Board of Directors of Baytex:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mboe)	Net Present Value of Future Net Revenue Before income taxes (10% discount rate – $ thousands)		
					Audited	Evaluated	Total
Development Pending Contingent Resources	Sproule Unconventional Limited	December 31, 2016	Canada	22,814	Nil	$103,899	$103,899

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mboe)
Development Unclarified Contingent Resources	Sproule Unconventional Limited	December 31, 2016	Canada	573,850

7. In our opinion, the reserves data and contingent resources 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 and contingent resources data that we reviewed but did not evaluate.

8. We have no responsibility to update the report referred to in paragraphs 5 and 6 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above on March 7, 2017.

Sproule Unconventional Limited

(signed) "*Cameron P. Six*"
Cameron P. Six, P.Eng.
President, CEO and Director

(signed) "*Alec Kovaltchouk*"
Alec Kovaltchouk, P.Geol
Manager, Geoscience and Partner

(signed) "*Stephanie D. Brunt*"
Stephanie D. Brunt, P. Eng
Petroleum Engineer

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 and audited Baytex's internal evaluation of the contingent resources data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2016, estimated using forecast prices and costs

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

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended form time to time (the "**COGE Handbook**") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. 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 and contingent resources data are in accordance with principles and definitions presented in the COGE Handbook.

5. 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, 2016, 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
Ryder Scott Company, L.P.	Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2016). Prepared: August 2016 to February 2017	United States of America	Nil	$2,339,255	Nil	$2,339,255

6. The following table sets forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in Baytex's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have audited and reported on to the management and Board of Directors of Baytex:

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mboe)	Net Present Value of Future Net Revenue Before income taxes (10% discount rate – $ thousands)		
					Audited	Evaluated	Total
Development Pending Contingent Resources	Ryder Scott Company, L.P.	December 31, 2016	United States of America	11,247	$107,115	Nil	$107,115

Classification	Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Resources Other than Reserves	Risked Volume (Mboe)
Development Unclarified Contingent Resources	Ryder Scott Company, L.P.	December 31, 2016	United States of America	59,903

7. In our opinion, the reserves data evaluated by us and the contingent resources data audited 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 and contingent resources data that we reviewed but did not evaluate or audit.

8. We have no responsibility to update the report referred to in paragraphs 5 and 6 for events and circumstances occurring after its preparation date.

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

Executed as to our report referred to above on March 7, 2017.

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

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

APPENDIX D

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 99.2

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2016, our internal control over financial reporting was effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2016.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of Baytex Energy Corp. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

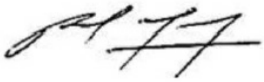
Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

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



James L. Bowzer
Chief Executive Officer
Baytex Energy Corp.



Rodney D. Gray
Chief Financial Officer
Baytex Energy Corp.

March 7, 2017

INDEPENDENT AUDITORS' REPORT

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

We have audited the accompanying consolidated financial statements of Baytex Energy Corp., which comprise the consolidated statements of financial position as at December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Baytex Energy Corp. as at December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Comparative Information

Without modifying our opinion, we draw attention to Note 13 to the consolidated financial statements which indicates that the comparative information presented as at and for the year ended December 31, 2015, has been adjusted and that an opening statement of financial position as at January 1, 2015 is not presented.

The consolidated financial statements of Baytex Energy Corp. as at and for the year ended December 31, 2015 excluding the adjustment described in Note 13 to the consolidated financial statements were audited by another auditor who expressed an unmodified opinion on those financial statements on March 2, 2016.

As part of our audit of the consolidated financial statements as at and for the year ended December 31, 2016, we audited the adjustment described in Note 13 to the consolidated financial statements that was applied to adjust the comparative information presented as at and for the year ended December 31, 2015, and the opening statement of financial position as at January 1, 2015 (not presented herein). In our opinion, the adjustment is appropriate and has been properly applied.

We were not engaged to audit, review, or apply any procedures to the December 31, 2015, consolidated financial statements or the January 1, 2015, consolidated statement of financial position, other than with respect to the adjustment described in Note 13 to the consolidated financial statements. Accordingly, we do not express an opinion or any other form of assurance on those financial statements taken as a whole.

Other Matter

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Baytex Energy Corp.'s internal control over financial reporting as of December 31, 2016, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 6, 2017 expressed an unmodified (unqualified) opinion on the effectiveness of Baytex Energy Corp.'s internal control over financial reporting.



Chartered Professional Accountants
March 6, 2017
Calgary, Canada

INDEPENDENT AUDITORS' REPORT

The Board of Directors and Shareholders of Baytex Energy Corp.

We have audited Baytex Energy Corp.'s internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Baytex Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management report on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Baytex Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated statement of financial position of Baytex Energy Corp. as of December 31, 2016, and the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the year ended December 31, 2016, and our report dated March 6, 2017 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Chartered Professional Accountants
March 6, 2017
Calgary, Canada

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited, before the effects of the adjustments to retrospectively apply the change in accounting discussed in Note 13 to the consolidated financial statements, the accompanying consolidated financial statements of Baytex Energy Corp. and subsidiaries (the “Company”), which comprise the consolidated statements of financial position as at December 31, 2015, and the consolidated statement of loss and comprehensive loss, consolidated statement of changes in equity, and consolidated statement of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information (the 2015 consolidated financial statements before the effects of the adjustments discussed in Note 13 to the consolidated financial statements are not presented herein).

Management's Responsibility for the Consolidated Financial Statements

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

Auditor's Responsibility

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

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

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

Opinion

In our opinion, the consolidated financial statements, before the effects of the adjustments to retrospectively apply the change in accounting discussed in Note 13 to the consolidated financial statements, present fairly, in all material respects, the financial position of Baytex Energy Corp. and subsidiaries as at December 31, 2015, and their financial performance and their cash flows for the year then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.



Chartered Professional Accountants
March 2, 2016
Calgary, Canada

Baytex Energy Corp.
Consolidated Statements of Financial Position
(thousands of Canadian dollars)

As at	December 31, 2016	December 31, 2015
ASSETS		
Current assets		
Cash	**$ 2,705**	$ 247
Trade and other receivables (note 18)	**112,171**	98,093
Financial derivatives (note 18)	**2,219**	106,573
	117,095	204,913
Non-current assets		
Financial derivatives (note 18)	**—**	4,417
Exploration and evaluation assets (note 6)	**308,462**	578,969
Oil and gas properties (note 7)	**4,152,169**	4,674,175
Other plant and equipment (note 8)	**16,359**	26,024
	$ 4,594,085	$ 5,488,498
LIABILITIES		
Current liabilities		
Trade and other payables (note 18)	**$ 112,973**	$ 267,838
Financial derivatives (note 18)	**28,532**	—
Onerous contracts (note 19)	**9,504**	—
	151,009	267,838
Non-current liabilities		
Bank loan (note 9)	**187,954**	252,172
Long-term notes (note 10)	**1,566,116**	1,602,757
Asset retirement obligations (note 11)	**331,517**	296,002
Deferred income tax liability (note 15)	**375,695**	655,255
Financial derivatives (note 18)	**2,833**	—
	2,615,124	3,074,024
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 12)	**4,422,661**	4,296,831
Contributed surplus (note 13)	**21,405**	22,045
Accumulated other comprehensive income	**629,863**	705,382
Deficit (note 13)	**(3,094,968)**	(2,609,784)
	1,978,961	2,414,474
	$ 4,594,085	$ 5,488,498

Commitments and contingencies (note 20)
Subsequent event (note 23)

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Income (Loss) and Comprehensive Income (Loss)
(thousands of Canadian dollars, except per common share amounts)

	Years Ended December 31	
	2016	2015
Revenue, net of royalties		
Petroleum and natural gas sales	**$ 780,095**	$ 1,121,424
Royalties	**(178,116)**	(241,425)
	601,979	879,999
Expenses		
Operating	**240,705**	320,187
Transportation	**28,257**	53,127
Blending	**9,622**	27,830
General and administrative	**50,866**	59,406
Exploration and evaluation (note 6)	**5,976**	8,775
Depletion and depreciation (notes 7 and 8)	**508,309**	661,858
Impairment (notes 6 and 7)	**423,176**	1,038,554
Share-based compensation (note 13)	**13,882**	24,573
Financing and interest (note 16)	**114,199**	111,660
Financial derivatives loss (gain) (note 18)	**43,207**	(142,729)
Foreign exchange (gain) loss (note 17)	**(42,678)**	210,713
Disposition of oil and gas properties (gain) loss (note 7)	**(43,907)**	1,519
Other expense (income)	**8,152**	(8,448)
	1,359,766	2,367,025
Net income (loss) before income taxes	**(757,787)**	(1,487,026)
Income tax (recovery) expense (note 15)		
Current income tax (recovery) expense	**(8,042)**	8,907
Deferred income tax (recovery)	**(264,561)**	(353,053)
	(272,603)	(344,146)
Net income (loss) attributable to shareholders	**$ (485,184)**	$ (1,142,880)
Other comprehensive income (loss)		
Foreign currency translation adjustment	**(75,519)**	505,807
Comprehensive income (loss)	**$ (560,703)**	$ (637,073)
Net income (loss) per common share (note 14)		
Basic	**$ (2.29)**	$ (5.77)
Diluted	**$ (2.29)**	$ (5.77)
Weighted average common shares (note 14)		
Basic	**212,298**	198,207
Diluted	**212,298**	198,207

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Changes in Equity
(thousands of Canadian dollars)

	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income (loss)	Deficit	**Total equity**
Balance at December 31, 2014 (note 13)	$ 3,580,825	$ 39,308	$ 199,575	$ (1,312,931)	**2,506,777**
Dividends to shareholders (note 12)	—	—	—	(153,973)	**(153,973)**
Vesting of share awards (note 12)	41,836	(41,836)	—	—	**—**
Share-based compensation (note 13)	—	24,573	—	—	**24,573**
Issued for cash (note 12)	632,494	—	—	—	**632,494**
Issuance costs, net of tax (note 12)	(19,301)	—	—	—	**(19,301)**
Issued pursuant to dividend reinvestment plan (note 12)	60,977	—	—	—	**60,977**
Comprehensive income (loss) for the year	—	—	505,807	(1,142,880)	**(637,073)**
Balance at December 31, 2015 (note 13)	$ 4,296,831	$ 22,045	$ 705,382	$ (2,609,784)	**2,414,474**
Vesting of share awards (note 12)	14,522	(14,522)	—	—	**—**
Share-based compensation (note 13)	—	13,882	—	—	**13,882**
Issued for cash (note 12)	115,014	—	—	—	**115,014**
Issuance costs, net of tax (note 12)	(3,706)	—	—	—	**(3,706)**
Comprehensive income (loss) for the year	—	—	(75,519)	(485,184)	**(560,703)**
Balance at December 31, 2016	$ 4,422,661	$ 21,405	$ 629,863	$ (3,094,968)	**1,978,961**

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Cash Flows
(thousands of Canadian dollars)

	Years Ended December 31	
	2016	2015
CASH PROVIDED BY (USED IN):		
Operating activities		
Net income (loss) for the year	**$ (485,184)**	$ (1,142,880)
Adjustments for:		
Share-based compensation (note 13)	**13,882**	24,573
Unrealized foreign exchange (gain) loss (note 17)	**(41,436)**	213,999
Exploration and evaluation (note 6)	**5,976**	8,775
Depletion and depreciation	**508,309**	661,858
Impairment (notes 6 and 7)	**423,176**	1,038,554
Non-cash financing and accretion (note 16)	**10,514**	8,256
Loss on onerous contracts (note 19)	**10,116**	—
Unrealized financial derivatives loss (note 18)	**140,136**	54,816
Disposition of oil and gas properties (gain) loss (note 7)	**(43,907)**	1,519
Deferred income tax (recovery)	**(264,561)**	(353,053)
Payments on onerous contracts (note 19)	**(770)**	—
Change in non-cash working capital (note 19)	**(23,270)**	43,891
Asset retirement obligations settled (note 11)	**(5,616)**	(10,888)
	247,365	549,420
Financing activities		
Payment of dividends	**—**	(109,806)
Decrease in bank loan	**(60,910)**	(439,465)
Tenders of long-term notes	**—**	(10,372)
Issuance of common shares, net of issuance costs (note 12)	**109,939**	606,095
	49,029	46,452
Investing activities		
Additions to exploration and evaluation assets (note 6)	**(4,716)**	(5,642)
Additions to oil and gas properties (note 7)	**(220,067)**	(515,397)
Property acquisitions	**(117)**	(2,070)
Proceeds from disposition of oil and gas properties (note 7)	**63,237**	423
Current income tax paid on dispositions	**—**	(8,181)
Dispositions to other plant and equipment, net of additions (note 8)	**5,129**	4,107
Change in non-cash working capital (note 19)	**(135,743)**	(70,968)
	(292,277)	(597,728)
Impact of foreign currency translation on cash balances	**(1,659)**	961
Change in cash	**2,458**	(895)
Cash, beginning of year	**247**	1,142
Cash, end of year	**$ 2,705**	$ 247
Supplementary information		
Interest paid	**$ 104,183**	$ 100,257
Income taxes paid	**$ 5,332**	$ 12,064

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The significant accounting policies set out below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex onMarch 6, 2017.

The consolidated financial statements have been prepared on the historical cost basis, with some exceptions as noted in the accounting policies set out below. The consolidated financial statements are presented in Canadian dollars, which is the Company’s functional currency. All financial information is rounded to the nearest thousand, except per share amounts and when otherwise indicated. Prior period financial statement amounts have been reclassified to conform with current period presentation and the adjustments to share-based compensation (see note 13).

Measurement Uncertainty and Judgments

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Accordingly, actual results can differ from those estimates. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, expenses, and disclosure of contingencies are discussed below.

Oil and Gas Activities
Reserves estimates can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion, asset retirement obligations, asset impairments and business combinations. The estimation of reserves is a complex process requiring significant judgment. The Company's reserves are estimated annually by independent reserves evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent or greater statistical probability of being recovered (total proved plus probable reserves) or a 10 percent or greater statistical probability of being recovered (total possible reserves). Changes to estimates such as forward price estimates, production costs, recovery rates and, accordingly, economic status of reserves may have a material impact on the consolidated financial statements.

The Company's capital assets are aggregated into cash-generating units based on management's judgment of their ability to generate largely independent cash flows. The cash-generating units are used to assess impairment and, accordingly, can directly impact the recoverability of the assets therein. Impairment of assets and groups of assets are calculated based on the higher of value-in-use calculations and fair value less cost to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, royalty rates, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and natural gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. Management applies judgment when it assesses internal and external factors to determine if indicators of impairment or indicators of impairment reversal exist.

The determination of technical feasibility and commercial viability of exploration and evaluation assets ("E&E") for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment.

Depletion and Depreciation
The amounts recorded for depletion of oil and gas properties are based on a unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. See "Oil and Gas Activities" above for discussion of estimates and judgments involved in reserve estimation.

Amounts recorded for depreciation are based on the estimated useful lives of depreciable assets which are reviewed by management at each reporting date.

Business Combinations
Business combinations are accounted for using the acquisition method of accounting. The determination of fair value of assets and liabilities acquired often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and exploration and evaluation assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net income (loss) can be affected as a result of changes in future depletion, depreciation, asset impairment or goodwill impairment.

Joint Control
Judgment is required to determine when the Company has joint control over a joint operation, which requires an assessment of the capital and operating activities of the projects undertaken with partners and when decisions in relation to those activities require unanimous consent.

Fair Value of Financial Instruments
Fair values of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs and are described in note 18. These estimates may vary from the actual prices achieved upon settlement of the financial instruments.

Share-based Compensation
Compensation expense related to awards granted under the Company's Share Award Incentive Plan is dependent on estimated fair values, forfeiture rates and, for performance awards, a payout multiplier based on past performance. Compensation expense may fluctuate due to changes in management's estimates.

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

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

Income Taxes
Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and differing interpretations require management judgment. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards may result in a material change in the Company's provision for income taxes. As such, income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Partnership. Intercompany balances, net income (loss) and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements.

A portion of the Company's exploration, development and production activities are conducted through jointly controlled operations. The financial statements reflect the Company's proportionate interest where the Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases. Joint control exists for contractual arrangements governing assets whereby the Company has less than 100 per cent working interest, all of the partners have control of the arrangement collectively, and spending on the project requires unanimous consent of all parties that collectively control the arrangement and share the associated risks.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting. The cost of an acquisition is measured as cash paid and the fair value of other assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed, including contingent liabilities, are measured at their fair values

at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the deficiency is credited to net income (loss) in the statements of income (loss) and comprehensive income (loss) in the period of acquisition. Associated transaction costs are expensed when incurred.

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

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

E&E Costs
Once the legal right to explore has been acquired, costs directly associated with an exploration well are capitalized as an intangible asset until the drilling of the well program/project is complete and the results have been evaluated. Such E&E costs may include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing. E&E costs are capitalized until technical feasibility and commercial viability of extracting petroleum and natural gas resources is considered to be determined. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. All such costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract value from the asset. If the asset is determined not to be technically feasible or economically viable, an impairment is charged to net income (loss). Upon determination of technical feasibility and commercial viability, the E&E assets attributable to those reserves are tested for impairment on transfer to oil and gas properties.

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

Depletion and Depreciation
The net carrying value of oil and gas properties is depleted using the unit-of-production method based on estimated proved and probable reserves. Future development costs, which are the estimated costs necessary to bring those reserves into production, are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil.

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

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

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively. Field inventory which is included in other plant and equipment is valued at the lower of cost, using the weighted average cost method, or net realizable value and is not depreciated.

Goodwill

Goodwill is the excess of the purchase price paid over the fair value of net identifiable assets acquired, which is inherently imprecise
as estimates and judgment are required in the determination of the fair value of assets and liabilities. Goodwill is assessed for impairment at least annually at year end, or more frequently if events or changes in circumstances indicate that the asset may be impaired. Impairment is recognized in net income (loss) and is not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal. Goodwill is not deductible for income tax purposes.

Impairment

Non-derivative financial assets

The Company assesses non-derivative financial assets at each reporting date to determine whether there is any objective evidence indicating that it is impaired. Objective evidence exists if one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset is measured as the difference between the amortized cost of the financial asset and its recoverable amount.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. All impairment losses are recognized in net income (loss). An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in net income (loss).

Non-financial Assets

E&E assets are assessed for impairment when they are reclassified to oil and gas properties and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. The Company assesses other assets or groups of assets for impairment whenever events or changes in circumstances indicate that the carrying value of an asset may not be recoverable.

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

The Company assesses its CGUs for impairment when indicators of impairment exist or at least annually for CGUs with goodwill. The Company compares the recoverable amount of the CGU to its carrying amount. A CGU's recoverable amount is the higher of its fair value less costs of disposal and its value-in-use. In assessing the recoverable amount, the estimated future cash flows are adjusted for the risks specific to the CGU and are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money. Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of any goodwill allocated to the CGU first, with any remaining impairment being allocated to the individual assets in the CGU on a pro-rata basis. Impairment is charged to net income (loss) in the period in which it occurs.

For all assets (other than goodwill), an assessment is made at each reporting date as to whether there is any indication that previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset’s carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized for the asset in prior years and circumstances indicate the impairment no longer exists. Such reversal is recognized in net income (loss). Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Asset Retirement Obligations

The Company recognizes a liability for the future asset retirement costs associated with its oil and gas properties discounted using the risk free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted to expense over its useful life. The liability is accreted until the date of expected settlement of the retirement obligation and is recognized within financing costs in the statements of income (loss) and comprehensive income (loss). Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign transactions
Transactions completed in currencies other than the functional currency are reflected in Canadian dollars at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to Canadian dollars at the period-end exchange rate. Revenue and expenses are translated to Canadian dollars using the average exchange rate for the period. Both realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income (loss).

Foreign operations
As several of the Company's subsidiaries operate and transact primarily in countries other than Canada, they accordingly have functional currencies other than the Canadian dollar. The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Assets and liabilities of foreign operations are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. The resulting unrealized gains or losses are included in accumulated other comprehensive income (loss) in shareholders' equity and are reclassified to net income (loss) when there has been a disposal or partial disposal of the foreign operation.

Revenue Recognition

Revenue associated with sales of petroleum and natural gas is recognized when title passes to the purchaser at the delivery point and collectability of the revenue is probable. Revenue from the production of petroleum and natural gas in which the Company has an interest with other producers is recognized based on the Company's working interest and the terms of the relevant agreements. Purchases and sales of products that are entered into in contemplation of each other with the same counterparty with the right and intent to settle net are recorded on a net basis.

Transportation Expense

Costs paid by Baytex for the transportation of crude oil, natural gas, condensate and NGLs to the point of title transfer are recognized when transportation is provided. For the U.S. operations, Baytex does not have sufficient information to bifurcate these costs and therefore transportation expenses has been included as part of operating expense.

Financial Instruments

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

Subsequent measurement of financial instruments is based on their initial classification. FVTPL financial assets are measured at fair value and changes in fair value are recognized in net income (loss). Available-for-sale financial assets are measured at fair value with changes in fair value recorded in other comprehensive income (loss) until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest method. Cash and financial derivatives are classified at FVTPL. Trade and other receivables are classified as loans and receivables, which are measured at amortized cost. Trade and other payables, dividends payable to shareholders, bank loan and long-term notes are classified as other financial liabilities, which are measured at amortized cost.

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts consist of a host contract and an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The embedded derivatives are measured at FVTPL.

The transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed immediately. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income (loss) over the term of the financial instrument. Debt issuance costs related to the restructuring of credit facilities are capitalized and amortized as financing costs over the term of the credit facilities.

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

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

Income Taxes

Current and deferred income taxes are recognized in net income (loss), except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity. When current income tax or deferred

income tax arises from the initial accounting for a business combination, the tax effect is included in the accounting for the business combination as goodwill.

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

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

Share-based Compensation Plans

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.8% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a payout multiplier. Under the Share Award Incentive Plan, common shares are issued as to one-sixth on the first anniversary date of the grant and as to one-sixth every six months thereafter (with the last issuance to occur 36 months following grant date (42 months for grants prior to 2016)). Expenses related to the Share Award Incentive Plan are determined based on the fair value of the share awards on the grant date. Both restricted and performance awards are expensed over the vesting period. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payments of dividends from the grant date to the applicable issue date.

4. CHANGES IN ACCOUNTING POLICIES

Future Accounting Pronouncements

Revenue from Contracts with Customers

In April 2016, the IASB issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which will replace IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The standard also requires extensive new disclosures, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 15 will be applied by Baytex on January 1, 2018. The Company is currently in the process of creating a plan to identify and review its various revenue streams and underlying contracts and assessing the impact on the consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9 *Financial Instruments* which is intended to replace IAS 39 *Financial Instruments: Recognition and Measurement.* The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. The Company currently does not apply hedge accounting to its derivative contracts nor does it intend to apply hedge accounting upon adoption of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. IFRS 9 will be applied by Baytex on January 1, 2018. The Company is currently evaluating its impact on the consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income (loss). The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. IFRS 16 will be applied by Baytex on January 1, 2019. The Company is currently evaluating the impact of the standard on the consolidated financial statements.

5. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the Company's geographic locations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2016**	2015	**2016**	2015	**2016**	2015	**2016**	2015
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 299,632**	$ 521,104	**$ 480,463**	$ 600,320	**$ —**	$ —	**$ 780,095**	$ 1,121,424
Royalties	**(37,720)**	(67,323)	**(140,396)**	(174,102)	**—**	—	**(178,116)**	(241,425)
	261,912	453,781	**340,067**	426,218	**—**	—	**601,979**	879,999
Expenses								
Operating	**142,242**	210,945	**98,463**	109,242	**—**	—	**240,705**	320,187
Transportation	**28,257**	53,127	**—**	—	**—**	—	**28,257**	53,127
Blending	**9,622**	27,830	**—**	—	**—**	—	**9,622**	27,830
General and administrative	**—**	—	**—**	—	**50,866**	59,406	**50,866**	59,406
Exploration and evaluation	**5,976**	8,775	**—**	—	**—**	—	**5,976**	8,775
Depletion and depreciation	**210,778**	279,744	**293,231**	377,847	**4,299**	4,267	**508,309**	661,858
Impairment	**256,559**	45,703	**166,617**	992,851	**—**		**423,176**	1,038,554
Share-based compensation (note 13)	**—**	—	**—**	—	**13,882**	24,573	**13,882**	24,573
Financing and interest	**—**	—	**—**	—	**114,199**	111,660	**114,199**	111,660
Financial derivatives (gain)	**—**	—	**—**	—	**43,207**	(142,729)	**43,207**	(142,729)
Foreign exchange loss	**—**	—	**—**	—	**(42,678)**	210,713	**(42,678)**	210,713
Disposition of oil and gas properties (gain) loss	**(3,883)**	1,769	**(40,024)**	(250)	**—**	—	**(43,907)**	1,519
Other expense (income)	**—**	—	**—**	—	**8,152**	(8,448)	**8,152**	(8,448)
	649,551	627,893	**518,287**	1,479,690	**191,927**	259,442	**1,359,766**	2,367,025
Net income (loss) before income taxes	**(387,639)**	(174,112)	**(178,220)**	(1,053,472)	**(191,927)**	(259,442)	**(757,787)**	(1,487,026)
Income tax (recovery) expense								
Current income tax (recovery) expense	**(6,577)**	6,577	**(1,156)**	1,946	**(309)**	384	**(8,042)**	8,907
Deferred income tax (recovery) expense	**(99,215)**	(39,191)	**(112,907)**	(324,940)	**(52,439)**	11,078	**(264,561)**	(353,053)
	(105,792)	(32,614)	**(114,063)**	(322,994)	**(52,748)**	11,462	**(272,603)**	(344,146)
Net income (loss)	**$ (281,847)**	$ (141,498)	**$ (64,157)**	$ (730,478)	**$ (139,179)**	$ (270,904)	**$ (485,184)**	$ (1,142,880)
Total oil and natural gas capital expenditures (1)	**$ 16,990**	$ 72,891	**$ 144,673**	$ 449,796	**$ —**	$ —	**$ 161,663**	$ 522,687

(1) Includes acquisitions, net of proceeds from divestitures.

As at	December 31, 2016	December 31, 2015
Canadian assets	**1,625,546**	$ 2,059,903
U.S. assets	**2,955,965**	3,304,647
Corporate assets	**12,574**	123,948
Total consolidated assets	**4,594,085**	$ 5,488,498

6. EXPLORATION AND EVALUATION ASSETS

	December 31, 2016	December 31, 2015
Balance, beginning of year	**$ 578,969**	$ 542,040
Capital expenditures	**4,716**	5,642
Property acquisitions, net of divestitures	**102**	1,813
Impairment	**(166,617)**	—
Exploration and evaluation expense	**(5,976)**	(8,775)
Transfer to oil and gas properties	**(85,069)**	(38,062)
Divestitures	**(2,455)**	(1,588)
Foreign currency translation	**(15,208)**	77,899
Balance, end of year	**$ 308,462**	$ 578,969

During the year ended December 31, 2016, the Company derecognized $166.6 million of exploration and evaluation assets in the U.S. CGU due to changes to the Company's development plan, which resulted in possible reserves being reclassified to contingent resources. In addition, the Company also transferred $85.1 million from exploration and evaluation assets to oil and gas properties upon establishment of proved and probable reserves in the U.S. CGU that were previously classified as possible reserves.

At December 31, 2016, there were no indicators of impairment for exploration and evaluation assets relating to CGUs in Canada.

7. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2014	**$ 6,431,760**	**$ (1,447,844)**	**$ 4,983,916**
Capital expenditures	515,397	—	515,397
Property acquisitions	551	—	551
Transferred from exploration and evaluation assets	38,062	—	38,062
Change in asset retirement obligations	10,722	—	10,722
Divestitures	(20,096)	19,449	(647)
Impairment	—	(755,613)	(755,613)
Foreign currency translation	607,885	(68,509)	539,376
Depletion	—	(657,589)	(657,589)
Balance, December 31, 2015	**$ 7,584,281**	**$ (2,910,106)**	**$ 4,674,175**
Capital expenditures	220,067	—	220,067
Property acquisitions	54	—	54
Transferred from exploration and evaluation assets	85,069	—	85,069
Change in asset retirement obligations	35,714	—	35,714
Divestitures	(59,874)	42,959	(16,915)
Impairment	—	(256,559)	(256,559)
Foreign currency translation	(101,274)	15,616	(85,658)
Depletion	—	(503,778)	(503,778)
Balance, December 31, 2016	**$ 7,764,037**	**$ (3,611,868)**	**$ 4,152,169**

For the year ended December 31, 2016, the Company recorded total impairment expense to oil and gas properties of $256.6 million (2015 - $755.6 million).

U.S. Assets

On July 27, 2016, the Company disposed of its operated interest in certain Eagle Ford properties for proceeds of $54.2 million, which consisted of $11.8 million of oil and gas properties and $2.3 million of exploration and evaluation assets, resulting in a gain on disposition of $40.1 million.

At December 31, 2016, the Company had no indicators of impairment in the U.S. CGU and as a result no impairment assessment was performed.

At December 31, 2015, indicators of impairment arose as a result of declining commodity prices. Impairment of $992.9 million ($741.3 million net of tax) was recorded in the U.S. CGU as a reduction to oil and gas properties of $709.9 million and the Company's remaining goodwill of $282.9 million. The recoverable amount for the U.S. CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment at December 31, 2015. The recoverable amount of oil and gas properties of $3,222.0 million for the U.S. CGU was estimated based on their fair value less costs of disposal at December 31, 2015.

Canadian Assets

At September 30, 2016, the Company recorded a $26.6 million impairment expense in its Lloydminster CGU on assets that were reclassified from oil and gas assets to assets held for sale prior to their disposition in the fourth quarter of 2016. The carrying value of the assets transferred to assets held for sale exceeded the fair value (being the sales price) resulting in the impairment. During 2016, the Company disposed of certain non-core assets in Canada for total proceeds of $9.0 million, which consisted of $5.1 million of oil and gas properties and $0.1 million of exploration and evaluation assets, resulting in a gain on disposition of $3.8 million.
At December 31, 2016, indicators of impairment existed for the Peace River CGU as a result of downward technical revisions to reserves. Impairment of $230.0 million was recorded in the Peace River CGU. The recoverable amount for the Peace River CGU was not sufficient to support the carrying amounts of the assets resulting in the impairment at December 31, 2016. The recoverable amount of oil and gas properties of $550.2 million for the Peace River CGU was estimated based on their fair value less costs of disposal at December 31, 2016. For impairment assessments of oil and gas properties, the Company estimates the recoverable amount using a discounted cash flow model based on an independent reserve report approved by the Board of Directors on an annual basis and a range of pre-tax discount rates of 10% to 15%.

The recoverable amount of the Peace River CGU was calculated at December 31, 2016 using the following benchmark reference prices for the years 2017 to 2021 adjusted for commodity differentials specific to the Company:

	2017	2018	2019	2020	2021
WTI crude oil (US$/bbl)	55.00	65.00	70.00	71.40	72.83
NYMEX natural gas (US$/MMBtu)	3.50	3.50	3.50	4.00	4.08
Exchange rate (CAD/USD)	1.28	1.22	1.18	1.18	1.18

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2021 have been adjusted for inflation at an annual rate of 2.0%.

The fair value less costs of disposal values used to determine the recoverable amount of the Peace River CGU are classified as Level 3 fair value measures as they are based on the Company's estimate of key assumptions that are not based on observable market data.

The results of the impairment test are sensitive to changes in any of the key judgments, such as a revision in reserves, a change in forecast commodity prices, expected royalties, future development capital expenditures or expected future production costs, which could decrease or increase the recoverable amounts of assets and result in additional impairment or recovery of impairment. For the Peace River CGU, an increase in the discount rate of 1 percent would result in additional impairment of $26.4 million. A decrease in commodity prices of 5 percent would result in additional impairment of $59.9 million.

In November 2015, the Company completed a disposition of certain non-core assets in its Lloydminster CGU and recorded an impairment of $45.7 million.

8. OTHER PLANT AND EQUIPMENT

	Cost	Accumulated depreciation	Net book value
Balance, December 31, 2014	**$ 76,708**	**$ (42,440)**	**$ 34,268**
Capital expenditures	3,577	—	3,577
Dispositions	(7,684)	—	(7,684)
Foreign currency translation	277	(147)	130
Depreciation	—	(4,267)	(4,267)
Balance, December 31, 2015	**72,878**	**(46,854)**	**26,024**
Capital expenditures	1,934	—	1,934
Dispositions, net of acquisitions	(7,063)	—	(7,063)
Foreign currency translation	(51)	46	(7)
Depreciation	—	(4,531)	(4,529)
Balance, December 31, 2016	**67,698**	**(51,339)**	**16,359**

9. BANK LOAN

	December 31, 2016	December 31, 2015
Bank loan - U.S. dollar denominated[1)]	**$ 191,286**	$ 237,861
Bank loan - Canadian dollar denominated	**—**	18,888
Bank loan - principal	**191,286**	256,749
Unamortized debt issuance costs	**(3,332)**	(4,577)
Bank loan	**$ 187,954**	$ 252,172

(1) U.S. dollar denominated bank loan balance as at December 31, 2016 was US$142.5 million (US$171.9 million as December 31, 2015)

On March 31, 2016, Baytex amended its credit facilities to grant the banking syndicate first priority security over its assets. The amended revolving extendible secured credit facilities are comprised of a US$25 million operating loan and a US$350 million syndicated loan for Baytex and a US$200 million syndicated loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants as detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. Baytex may request an extension of the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year period at any time). Advances (including letters of credit) under the Revolving Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex exceeds any of the covenants under the Revolving Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At December 31, 2016, Baytex had $12.6 million of outstanding letters of credit (December 31, 2015 - $12.4 million) under the Revolving Facilities.

At December 31, 2016, Baytex was in compliance with all of the covenants contained in the Revolving Facilities. The following table summarizes the financial covenants contained in the Revolving Facilities and Baytex's compliance therewith as at December 31, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at December 31, 2016**	**December 31, 2016 to March 31, 2018**	**June 30, 2018 to September 30, 2018**	**December 31, 2018**	**Thereafter**
Senior Secured Debt [(1)] to Bank EBITDA [(2)] (Maximum Ratio)	0.6:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage [(3)] (Minimum Ratio)	3.6:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2016, the Company's Senior Secured Debt totaled $204 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2016 was $373 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2016 were $104 million.

10. LONG-TERM NOTES

	December 31, 2016	December 31, 2015
7.5% notes (US$6,400 – principal) due April 1, 2020	**$ 8,593**	$ 8,858
6.75% notes (US$150,000 – principal) due February 17, 2021	**201,405**	207,600
5.125% notes (US$400,000 – principal) due June 1, 2021	**537,080**	553,600
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**537,080**	553,600
Total long-term notes - principal	**1,584,158**	1,623,658
Unamortized debt issuance costs	**(18,042)**	(20,901)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,566,116**	$ 1,602,757

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Revolving Facilities and long-term notes unless the Company maintains a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 9) to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at December 31, 2016, the fixed charge coverage ratio was 3.59:1.00.

11. ASSET RETIREMENT OBLIGATIONS

	December 31, 2016	December 31, 2015
Balance, beginning of year	**$ 296,002**	$ 286,032
Liabilities incurred	**5,642**	4,964
Liabilities settled	**(5,616)**	(10,888)
Liabilities acquired	**—**	593
Liabilities divested	**(10,590)**	(10,578)
Accretion	**6,174**	6,262
Change in estimate[(1)]	**20,402**	33,266
Changes in discount rates and inflation rates	**20,260**	(17,523)
Foreign currency translation	**(757)**	3,874
Balance, end of year	**$ 331,517**	$ 296,002

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

The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 50 years. The undiscounted amount of estimated cash flow required to settle the asset retirement obligations is $605.4 million (December 31, 2015 - $561.4 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2016 using an estimated annual inflation rate of 1.75% (December 31, 2015 - 1.50%) and discounted at a risk free rate of 2.25% (December 31, 2015 - 2.25%) is $331.5 million (December 31, 2015 - $296.0 million).

12. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2016, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meetings of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2014	**168,107**	**$ 3,580,825**
Transfer from contributed surplus on vesting and conversion of share awards	1,092	41,836
Issued for cash	36,455	632,494
Issuance costs, net of tax	—	(19,301)
Issued pursuant to dividend reinvestment plan	4,929	60,977
Balance, December 31, 2015	**210,583**	**$ 4,296,831**
Transfer from contributed surplus on vesting and conversion of share awards	958	14,522
Issued for cash	21,908	115,014
Issuance costs, net of tax	—	(3,706)
Balance, December 31, 2016	**233,449**	**$ 4,422,661**

On December 12, 2016, Baytex issued 21,907,500 common shares for aggregate gross proceeds of approximately $115.0 million ($109.9 million net of issue costs). Issuance costs of $5.1 million ($3.7 million after tax) were incurred and recorded as a reduction to shareholders' capital.

On April 2, 2015, Baytex issued 36,455,000 common shares for aggregate gross proceeds of approximately $632.5 million ($606.0 million net of issue costs). Issuance costs of $26.4 million ($19.3 million after tax) were incurred and recorded as a reduction to shareholders' capital.

Baytex has a Dividend Reinvestment Plan (the "DRIP") that allows eligible holders in Canada and the United States to reinvest their monthly cash dividends to acquire additional common shares. At the discretion of Baytex, common shares will either be issued from treasury or acquired in the open market at prevailing market prices. Pursuant to the terms of the DRIP, common shares are issued from treasury at a three percent discount to the arithmetic average of the daily volume weighted average trading prices of the common shares on the Toronto Stock Exchange (in respect of participants resident in Canada or any jurisdiction other than the United States) or the New York Stock Exchange (in respect of participants resident in the United States) for the period commencing on the second business day after the dividend record date and ending on the second business day immediately prior to the dividend payment date. Baytex reserves the right at any time to change or eliminate the discount on common shares acquired through the DRIP from treasury. During the year ended December 31, 2015, a total of 4,928,529 common shares were issued in accordance with this plan.

During the year ended December 31, 2015, the Company declared dividends of $0.80 per share totaling $154.0 million ($96.6 million, net of DRIP). The Company suspended the monthly dividend in September 2015 due to commodity prices and to preserve liquidity.

13. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $13.9 million for the year ended December 31, 2016 ($24.6 million for the year ended December 31, 2015).

The weighted average fair value of share awards granted during the year ended December 31, 2016 was $3.04 per restricted and performance award (for the year ended December 31, 2015, $17.17 per restricted and performance award).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[(1)]	Total number of share awards
Balance, December 31, 2014	**747**	**615**	**1,362**
Granted	615	503	1,118
Vested and converted to common shares	(432)	(382)	(814)
Forfeited	(201)	(123)	(324)
Balance, December 31, 2015	**729**	**613**	**1,342**
Granted	1,313	1,583	2,896
Vested and converted to common shares	(450)	(409)	(859)
Forfeited	(84)	(50)	(134)
Balance, December 31, 2016	**1,508**	**1,737**	**3,245**

(1) Based on underlying awards before applying the payout multiplier which can range from 0x to 2x.

During the year, the Company identified an immaterial error relating to share-based compensation expense in the previously issued financial statements. The estimated forfeiture rate was improperly applied to share awards that had previously vested and transferred to share capital, thereby understating share-based compensation expense. The Company concluded that the error was not material to the Company's previously filed financial statements and the corrected adjustments have been applied to the comparative information in these consolidated financial statements.

For the year ended December 31, 2015, an adjustment of $9.2 million has been recorded to increase both the share-based compensation expense and contributed surplus. Net loss per share (basic and diluted) increased by $0.05 per share to $5.77 per share for the year ended December 31, 2015. As at January 1, 2015, an adjustment of $8.2 million has been recorded to increase both the deficit and contributed surplus. As this adjustment was not material, an opening statement of financial position as at January 1, 2015 is not presented.

14. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income per share based on the net income (loss) attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the year.

	Years Ended December 31					
	2016			2015		
	Net loss	**Common shares (000s)**	**Net loss per share**	Net loss	Common shares (000s)	Net loss per share
Net income (loss) - basic	**$ (485,184)**	**212,298**	**$ (2.29)**	$ (1,142,880)	198,207	$ (5.77)
Dilutive effect of share awards	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (485,184)**	**212,298**	**$ (2.29)**	$ (1,142,880)	198,207	$ (5.77)

For the year ended December 31, 2016, 3.2 million share awards were anti-dilutive (December 31, 2015 - 1.3 million share awards).

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2016	2015
Net income (loss) before income taxes	**$ (757,787)**	$ (1,487,026)
Expected income taxes at the statutory rate of 27.00% (2015 - 26.24%)[1]	**(204,602)**	(390,196)
Increase (decrease) in income tax recovery resulting from:		
Share-based compensation	**3,610**	6,449
Non-taxable portion of foreign exchange (gain) loss	**(5,309)**	27,910
Effect of change in income tax rates[1]	**1,180**	13,246
Effect of rate adjustments for foreign jurisdictions	**(63,745)**	(120,943)
Effect of change in deferred tax benefit not recognized[2]	**(5,309)**	40,142
Impairment of goodwill	**—**	74,025
Other	**1,572**	5,221
Income tax (recovery)	**$ (272,603)**	$ (344,146)

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Alberta (from 10% to 12%), offset by a decrease in the Texas franchise tax rate (from 1.00% to 0.75%).

(2) A deferred income tax asset has not been recognized for allowable capital losses of $129 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes ($149 million as at December 31, 2015).

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the “CRA”) that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments follow the previously disclosed letter from the CRA received by Baytex in November 2014 proposing to issue such reassessments.

Baytex remains confident that the tax filings of the affected entities are correct and in September 2016, filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of CRA; a process that Baytex estimates could take up to two years. If the Appeals Division upholds the notices of reassessment Baytex has the right to appeal to the Tax Court of Canada; a process that Baytex estimates could take a further two years. Should Baytex be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that Baytex estimates could take another two years and potentially longer. The reassessments do not require Baytex to pay any amounts in order to participate in the appeals process.

By way of background, Baytex acquired all of the interests in several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the “Losses”). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, Baytex would owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available for “carry back” to the years 2012 through 2015.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2016	Recognized in Net Loss	Share Issuance Costs	Foreign Currency Translation Adjustment	**December 31, 2016**
Taxable temporary differences:					
Petroleum and natural gas properties	$ (1,105,470)	$ 112,710	$ —	$ 25,181	**$ (967,579)**
Financial derivatives	(29,961)	37,830	—	—	**7,869**
Deferred income	(28,387)	27,968	—	—	**(419)**
Other	(6,595)	2,327	1,370	(2,120)	**(5,018)**
Deductible temporary differences:					
Asset retirement obligations	83,189	10,231	—	(404)	**93,016**
Financial derivatives	1,582	(1,582)	—	—	**—**
Non-capital losses	383,450	30,530	—	(9,028)	**404,952**
Finance costs	46,937	44,547	—	—	**91,484**
Net deferred income tax liability[1]	$ (655,255)	$ 264,561	$ 1,370	$ 13,629	**$ (375,695)**

(1) Non-capital loss carry-forwards at December 31, 2016 totaled $1,191.7 million and expire from 2023 to 2036.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2015	Recognized in Net Loss	Share Issuance Costs	Foreign Currency Translation Adjustment	**December 31, 2015**
Taxable temporary differences:					
Petroleum and natural gas properties	$ (1,136,083)	$ 188,781	$ —	$ (158,168)	**$ (1,105,470)**
Financial derivatives	(45,950)	15,989	—	—	**(29,961)**
Deferred income	(81,979)	53,592	—	—	**(28,387)**
Other	(7,222)	(10,096)	7,099	3,624	**(6,595)**
Deductible temporary differences:					
Asset retirement obligations	74,918	6,880	—	1,391	**83,189**
Financial derivatives	5,341	(3,759)	—	—	**1,582**
Non-capital losses	227,370	112,802	—	43,278	**383,450**
Finance costs	58,073	(11,136)	—	—	**46,937**
Net deferred income tax liability[1]	$ (905,532)	$ 353,053	$ 7,099	$ (109,875)	**$ (655,255)**

(1) Non-capital loss carry-forwards at December 31, 2015 totaled $1,110.0 million and expire from 2023 to 2035.

16. FINANCING AND INTEREST

	Years Ended December 31	
	2016	2015
Interest on bank loan	**$ 12,860**	$ 14,303
Interest on long-term notes	**90,825**	89,101
Non-cash financing	**4,340**	1,994
Accretion on asset retirement obligations	**6,174**	6,262
Financing and interest	**$ 114,199**	$ 111,660

17.FOREIGN EXCHANGE

	Years Ended December 31	
	2016	2015
Unrealized foreign exchange (gain) loss	**$ (41,436)**	$ 213,999
Realized foreign exchange gain	**(1,242)**	(3,286)
Foreign exchange (gain) loss	**$ (42,678)**	$ 210,713

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, bank loan and long-term notes.

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. To estimate fair values of its financial instruments, Baytex uses quoted market prices when available, or third-party models and valuation methodologies that use observable market data. These estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. The fair values of financial instruments, other than financial derivatives, bank loan and long-term notes, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of financial derivatives are based on mark-to-market values of the underlying financial derivative contracts. The fair value of the bank loan approximates its carrying value as it is at a market rate of interest. The fair value of the long-term notes are based on the trading value of the notes.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	December 31, 2016		December 31, 2015		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL[(1)]					
Cash	**$ 2,705**	**$ 2,705**	$ 247	$ 247	Level 1
Derivatives	**2,219**	**2,219**	110,990	110,990	Level 2
Total FVTPL[(1)]	**$ 4,924**	**$ 4,924**	$ 111,237	$ 111,237	
Loans and receivables					
Trade and other receivables	**$ 112,171**	**$ 112,171**	$ 98,093	$ 98,093	—
Total loans and receivables	**$ 112,171**	**$ 112,171**	$ 98,093	$ 98,093	
Financial Liabilities					
FVTPL[(1)]					
Derivatives	**$ (31,365)**	**$ (31,365)**	$ —	$ —	Level 2
Total FVTPL[(1)]	**$ (31,365)**	**$ (31,365)**	$ —	$ —	
Other financial liabilities					
Trade and other payables	**$ (112,973)**	**$ (112,973)**	$ (267,838)	$ (267,838)	—
Bank loan	**(187,954)**	**(191,286)**	(252,172)	(256,749)	—
Long-term notes	**(1,566,116)**	**(1,435,165)**	(1,602,757)	(1,287,679)	Level 1
Total other financial liabilities	**$ (1,867,043)**	**$ (1,739,424)**	$ (2,122,767)	$ (1,812,266)	

(1) FVTPL means fair value through profit or loss.

There were no transfers between Level 1 and 2 in either 2016 or 2015.

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Company does not enter into derivative contracts for speculative purposes.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign Currency Risk

Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its bank loan and long-term notes, crude oil sales based on U.S. dollar benchmark prices and commodity contracts that are settled in U.S. dollars. The Company's net income (loss), comprehensive income (loss) and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of foreign exchange rate fluctuations, the Company may enter into agreements to fix the Canadian dollar -U.S. dollar exchange rate. At December 31, 2016, the Company did not have any currency derivative contracts outstanding.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income (loss) before income taxes by approximately $9.8 million.

The carrying amounts of the Company’s U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	December 31, 2016	December 31, 2015	**December 31, 2016**	December 31, 2015
U.S. dollar denominated	**US$66,950**	US$124,218	**US$1,197,732**	US$1,240,308

Interest Rate Risk

The Company's interest rate risk arises from the floating rate Revolving Facilities (note 9). As at December 31,2016, $191.3 million of the Company's total debt is subject to movements in floating interest rates. A change of 100 basis points in interest rates would impact net income (loss) before income taxes for the year ended December 31, 2016 by approximately $3.2 million. Baytex uses a combination of short-term and long-term debt to finance operations.

Commodity Price Risk

Baytex monitors and, when appropriate, utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives are governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities.

When assessing the potential impact of oil price changes on the financial derivative contracts outstanding as at December 312016, a 10% increase in oil prices would increase the unrealized loss at December 31, 2016 by $39.0 million, while a 10% decrease would decrease the unrealized loss at December 31, 2016 by $41.4 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 312016, a 10% increase in natural gas prices would increase the unrealized loss at December 31, 2015 by $6.5 million, while a 10% decrease would decrease the unrealized loss at December 31, 2015 by $8.1 million.

Financial Derivative Contracts

Baytex had the following financial derivative contracts:

	Period	Volume	Price/Unit[1]	Index	Fair Value[3] *($ millions)*
Oil					
3-way option[2]	Jan 2017 to Dec 2017	14,500 bbl/d	US$58.60/US$47.17/US$37.24	WTI	$ (14.8)
Basis swap	Jan 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42	WCS	$ 2.2
Fixed - Sell	Jan 2017 to Dec 2017	3,500 bbl/d	US$54.46	WTI	$ (3.2)
Fixed - Sell	Jan 2018 to Dec 2018	2,000 bbl/d	US$54.40	WTI	$ (2.0)
Basis swap[4]	Mar 2017 to Jun 2017	1,000 bbl/d	WTI less US$14.30	WCS	$ —
Basis swap[4]	Apr 2017 to Jun 2017	2,000 bbl/d	WTI less US$13.50	WCS	$ —
Basis swap[4]	Jul 2017 to Sep 2017	2,000 bbl/d	WTI less US$14.25	WCS	$ —
Natural Gas					
Fixed - Sell	Jan 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX	$ (7.2)
Fixed - Sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX	$ (0.5)
Fixed - Sell	Jan 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO	$ (3.3)
Fixed - Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO	$ (0.3)
Total					**$ (29.1)**
Current asset					$ 2.2
Current liability					$ (28.5)
Non-current liability					$ (2.8)

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$50/US$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives the market price when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.
(3) Fair values as at December 31, 2016. For the purposes of the table, contracts entered subsequent to December 31, 2016 will have no fair value assigned.
(4) Contracts entered subsequent to December 31, 2016.

Financial derivatives are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income (loss) and comprehensive income (loss):

	Years Ended December 31	
	2016	2015
Realized financial derivatives gain	**$ (96,929)**	$ (197,545)
Unrealized financial derivatives loss - commodity	**140,136**	54,318
Unrealized financial derivatives loss - redemption feature on long-term notes	**—**	498
Financial derivatives loss (gain)	**$ 43,207**	$ (142,729)

Physical Delivery Contracts

The following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments; therefore, no asset or liability has been recognized in the consolidated financial statements.

Heavy Oil	Period	Volume	Price/Unit[1]
WCS Blend[2]	Mar 2017 to Jun 2017	2,000 bbl/d	WTI less US$14.33

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) Contracts entered subsequent to December 31, 2016.

As at December 31, 2016, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

	Period	Term volume
Raw bitumen	Jan 2017 to Mar 2017	5,650 bbl/d
Raw bitumen	Apr 2017 to Dec 2017	5,000 bbl/d

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures. As at December 31, 2016, Baytex had available unused bank credit facilities in the amount of $580.8 million (as at December 31, 2015 - $820.1 million). In the event the Company is not able to comply with the financial covenants contained in agreements with its lenders, the Company's ability to access additional debt may be restricted.

The timing of cash outflows relating to financial liabilities as at December 31, 2016 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 112,973**	$ 112,973	$ —	$ —	$ —
Bank loan[1] [2]	**191,286**	—	191,286	—	—
Long-term notes[2]	**1,584,158**	—	—	747,078	837,080
Interest on long-term notes[3]	**404,769**	64,325	128,650	127,847	83,947
	$ 2,293,186	$ 177,298	$ 319,936	$ 874,925	$ 921,027

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be repaid on such date.
(2) Principal amount of instruments.
(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. Most of the Company's trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit and/or parental guarantees may be obtained prior to the commencement of business with certain counterparties. None of the Company's financial assets are secured by any other type of collateral. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on accounts receivable at December 31, 2016 relates to accrued revenues for December 2016. Accounts receivables from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. At December 31, 2016, $17.8 million of accounts receivable relates to joint interest receivables from the operator of our joint operations in the Eagle Ford.

Should Baytex determine that the ultimate collection of a receivable is in doubt, the carrying amount of accounts receivable is reduced by the use of an allowance for doubtful accounts and a charge to net income (loss). If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. For the year ended December 31, 2016, there were no changes to the allowance for doubtful accounts (2015 - $0.1 million added).

As at December 31, 2016, allowance for doubtful accounts was $1.4 million (2015 - $1.4 million). In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2016, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $0.9 million (2015 - $1.4 million).

The Company's trade and other receivables were aged as follows at December 31, 2016:

Trade and Other Receivables Aging[1]	**December 31, 2016**
Current (less than 30 days)	**$ 82,968**
31-60 days	**1,234**
61-90 days	**288**
Past due (more than 90 days)	**934**
	$ 85,424

(1) Excludes $24.7 million of cash calls paid to the operator of our U.S. properties and $2.1 million of prepaid expenses that have been classified as trade and other receivables.

19.SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Years Ended December 31	
	2016	2015
Trade and other receivables	**$ (14,078)**	$ 105,425
Trade and other payables	**(154,865)**	(130,423)
	$ (168,943)	$ (24,998)
Changes in non-cash working capital related to:		
Operating activities	**$ (23,270)**	$ 43,891
Investing activities	**(135,743)**	(70,968)
Current income tax paid on dispositions	**—**	(8,181)
Foreign currency translation on non-cash working capital	**(9,930)**	10,260
	$ (168,943)	$ (24,998)

Onerous Contracts

Onerous contracts result from unfavorable leases in which the unavoidable costs of meeting the obligations under the contracts exceed the economic benefits expected to be received.

		Amount
Balance, December 31, 2014 and 2015	**$**	**—**
Liabilities incurred		10,116
Liabilities settled		(770)
Foreign currency translation		158
Balance, December 31, 2016	**$**	**9,504**

As at December 31, 2016, the Company has a provision totaling$9.5 million related to onerous contracts (December 31, 2015 - nil). The provision represents the difference between the minimum future payments that we are required to make and the estimated recoveries. During the year ended December 31, 2016, the Company recognized $10.1 million of losses on onerous contracts relating to an office sublease and a transportation agreement which were recorded in other expense (income).

Income Statement Presentation

Baytex's consolidated statements of income (loss) and comprehensive income (loss) are prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2016	2015
Operating	**$ 9,528**	$ 13,180
General and administrative	**23,070**	28,432
Total employee compensation costs	**$ 32,598**	$ 41,612

20. COMMITMENTS AND CONTINGENCIES

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of December 31, 2016, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Operating leases	**$ 38,982**	8,164	15,511	12,679	2,628
Processing agreements	**48,833**	9,631	11,130	9,043	19,029
Transportation agreements	**59,172**	10,998	23,670	22,674	1,830
Total	**$ 146,987**	$ 28,793	$ 50,311	$ 44,396	$ 23,487

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

Operating lease and sublease payments recognized as an expense during the year ended December 31, 2016 were $7.7 million (December 31, 2015 - $8.0 million). Baytex has entered into operating leases on office buildings in the ordinary course of business. The Company's operating lease agreements do not contain any contingent rent clauses. The Company has the option to renew or extend the leases on its office building with the new lease terms to be based on current market prices. None of the operating lease agreements contain purchase options or escalation clauses or any restrictions regarding dividends, further leases or additional debt.

The litigation and claims that Baytex is engaged with, which arose in the normal course of operations, are not expected to materially affect the Company's financial position or reported results of operations.

21. RELATED PARTIES

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Transactions with key management personnel (including directors) are noted in the table below:

	Years Ended December 31	
	2016	2015
Short-term employee benefits	**7,278**	$ 6,831
Share-based compensation	**6,613**	12,032
Termination payments	**—**	549
Total compensation for key management personnel	**13,891**	$ 19,412

22. CAPITAL DISCLOSURES

The Company's objectives when managing capital are to: (i) maintain financial flexibility in its capital structure; (ii) optimize its cost of capital at an acceptable level of risk; and (iii) preserve its ability to access capital to sustain the future development of its business through maintenance of investor, creditor and market confidence.

Baytex considers its capital structure to include net debt and shareholders' equity. Baytex monitors capital based on the current and projected ratio of net debt to funds from operations and the current and projected level of its undrawn credit facilities. Historically and under normal operating conditions, the Company's objective is to maintain a net debt to funds from operations ratio of less than two times and to have access to undrawn credit facilities of not less than $100 million. The net debt to funds from operations ratio may increase beyond two times and the undrawn credit facilities may decrease to below $100 million at certain times due to a number of factors including changes to commodity prices, acquisitions, and changes in the credit market.

These objectives and strategy are reviewed on an annual basis. With the significant decrease in commodity prices, Baytex's net debt to funds from operations ratio has exceeded its target but the Company has maintained access to at least $100 million in undrawn credit facilities. The Company's financial strategy is designed to maintain a flexible capital structure consistent with the objectives stated above and to respond to changes in economic conditions and the risk characteristics of its underlying assets. In order to manage its capital, the Company may adjust its level of capital spending, issue new shares or debt, adjust the amount of

its dividends or sell assets to reduce debt. In the current commodity environment the Company's objective is to have access to undrawn credit facilities of not less than $100 million and to manage its capital to maintain liquidity.

As at December 31, 2016, Baytex is in compliance with all financial covenants relating to its senior unsecured notes and Revolving Facilities.

	Years Ended December 31	
	2016	2015
Cash flow from operating activities	**$ 247,365**	$ 549,420
Change in non-cash working capital	**23,270**	(43,891)
Asset retirement expenditures	**5,616**	10,888
Funds from operations[(1)]	**$ 276,251**	$ 516,417

	As at December 31	
	2016	2015
Bank loan - principal	**191,286**	$ 256,749
Long-term notes - principal	**1,584,158**	1,623,658
Trade and other payables	**112,973**	267,838
Cash	**(2,705)**	(247)
Trade and other receivables	**(112,171)**	(98,093)
Net debt[(1)]	**$ 1,773,541**	$ 2,049,905

(1) Funds from operations and net debt as presented does not have any standardized meaning prescribed by IFRS and, therefore, they may not be comparable with the calculation of similar measures for other entities.

	As at December 31	
	2016	2015
Available undrawn credit facilities	**$ 580,767**	$ 820,051
Net debt to funds from operations ratio	**6.4**	4.0

23. SUBSEQUENT EVENT

On January 20, 2017, Baytex acquired heavy oil properties in the Peace River area of Alberta for total consideration of $66 million. The consideration paid consists of $91 million of oil and gas assets, $5 million of accounts payable and $20 million of asset retirement obligations. The acquisition provides additional development opportunities and the acquired properties are located immediately adjacent to Baytex's existing Peace River lands.

Exhibit 99.3

BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2016 and 2015
Dated March 6, 2017

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2016 and 2015. This information is provided as of March 6, 2017. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the year ended December 31, 2016 ("2016") have been compared with the results for the year ended December 31, 2015 ("2015") and the results for the three months ended December 31, 2016 ("Q4/2016") have been compared with the results for the three months ended December 31, 2015 ("Q4/2015"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2016 and 2015, together with the accompanying notes and the Annual Information Form for the year ended December 31, 2016. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

CAPITAL MANAGEMENT MEASURES

In this MD&A, we refer to certain capital management measures as outlined in note 22 to the consolidated financial statements, such as funds from operations and net debt which do not have any standardized meaning prescribed by generally accepted accounting principles in Canada ("GAAP"). While funds from operations and net debt are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers.

Funds from Operations

We consider funds from operations ("FFO") a key measure that provides a more complete understanding of our results of operations and financial performance, including our ability to generate funds for capital investments, debt repayment and potential dividends. We believe that this measure provides a meaningful assessment of our operations by eliminating certain non-cash charges. However, funds from operations should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income (loss).

The following table reconciles cash flow from operating activities to funds from operations.

	Years Ended December 31	
($ thousands)	**2016**	2015
Cash flow from operating activities	**$ 247,365**	$ 549,420
Change in non-cash working capital	**23,270**	(43,891)
Asset retirement expenditures	**5,616**	10,888
Funds from operations	**$ 276,251**	$ 516,417

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity.

The following table summarizes our calculation of net debt.

($ thousands)	**December 31, 2016**	December 31, 2015
Bank loan[1]	**$ 191,286**	$ 256,749
Long-term notes[1]	**1,584,158**	1,623,658
Working capital (surplus) deficiency[2]	**(1,903)**	169,498
Net debt	**$ 1,773,541**	$ 2,049,905

(1) Principal amount of instruments expressed in Canadian dollars.
(2) Working capital is current assets less current liabilities (excluding current financial derivatives and onerous contracts).

NON-GAAP FINANCIAL MEASURES

In this MD&A, we refer to certain financial measures (such as operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by GAAP. While operating netback and EBITDA are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures by other issuers. We believe that the presentation of these non-GAAP measures provide useful information to investors and shareholders as the measures provide increased transparency and the ability to better analyze against prior periods on a comparable basis.

Operating Netback

We define operating netback as oil and natural gas revenue, less royalties, operating expense and transportation expense. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in assessing our ability to generate cash margin on a unit of production basis.

	Years Ended December 31	
($ thousands)	**2016**	2015
Petroleum and natural gas revenue	**780,095**	1,121,424
Blending expense	**(9,622)**	(27,830)
Oil and natural gas revenue	**770,473**	1,093,594
Royalties	**178,116**	241,425
Operating expense	**240,705**	320,187
Transportation expense	**28,257**	53,127
Operating netback	**323,395**	478,855
Realized financial derivative gain	**96,929**	197,545
Operating netback after realized financial derivatives gain	**420,324**	676,400

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants. The following table reconciles net income (loss) to Bank EBITDA.

	Years Ended December 31	
($ thousands)	**2016**	2015
Net income (loss)	**$ (485,184)**	$ (1,142,880)
Plus:		
Financing and interest	**114,199**	111,660
Unrealized foreign exchange (gain) loss	**(41,436)**	213,999
Unrealized financial derivatives loss	**140,136**	54,816
Current income tax (recovery) expense	**(8,042)**	8,907
Deferred income tax (recovery)	**(264,561)**	(353,053)
Depletion and depreciation	**508,309**	661,858
Impairment	**423,176**	1,038,554
Disposition of oil and gas properties (gain) loss	**(43,907)**	1,519
Non-cash items[(1)]	**29,974**	33,348
Bank EBITDA	**$ 372,664**	$ 628,728

(1) Non-cash items include share-based compensation, exploration and evaluation expense and non-cash other expense.

YEAR END HIGHLIGHTS

2016 presented many challenges for the oil and gas industry and for Baytex. With the low commodity price environment, we made significant adjustments to our business to maintain strong levels of financial liquidity. We reduced our capital spending, emphasized cost reductions in all facets of the business, renegotiated our credit facilities, raised equity to fund an acquisition that closed in early 2017 and disposed of certain non-core assets.

Production for the year averaged 69,509 boe/d, which was consistent with our guidance of 68,000 - 70,000 boe/d. In the Eagle Ford, production averaged 36,573 boe/d, an 8% decrease from 2015. The reduced number of completions combined with the sale of approximately 1,000 boe/d of operated production contributed to the decrease on our Eagle Ford assets from 2015. In Canada, production was 32,936 boe/d for 2016 compared to 44,691 boe/d in 2015. Due to the low price environment, we deferred all operated heavy oil drilling including development and stratigraphic test wells. This reduced level of activity caused production to decrease from 2015. In addition, we shut in production with low or negative margins for part of the year which reduced annual average production by approximately 2,400 boe/d.

Oil prices were at multi-year low levels in 2016 with continued over supply and high inventory levels. In Q1/2016, the price of West Texas Intermediate light oil ("WTI") averaged US$33.45/bbl. Prices stabilized in Q2/2016 and Q3/2016 with WTI averaging approximately US$45/bbl before the Organization of the Petroleum Exporting Countries (“OPEC”) announcement on November 30, 2016 which resulted in WTI oil prices rising above US$50/bbl for the last part of 2016. WTI averaged US$43.33/bbl during 2016 compared to US$48.79/bbl in 2015 representing a decrease of $5.48/bbl. Natural gas prices also decreased from 2015 with AECO decreasing 24% from $2.74/mcf in 2015 to $2.09/mcf in 2016 and NYMEX decreasing 8% from US$2.66/mmbtu in 2015 to US$2.46/mmbtu in 2016. The large AECO discount to Henry Hub is due to the oversupply of gas in the Western Canadian Sedimentary Basin. The decrease in commodity prices during 2016 reduced our revenue per boe to $30.29/boe from $35.40/boe for 2015.

During 2016, we successfully reduced our cost structure to help mitigate some of the commodity price decrease. In the Eagle Ford, the costs to drill, complete and equip our wells decreased throughout the year and averaged approximately US$4.5 million per well in Q4/2016, as compared to US$8.2 million per well in late 2014. Operating expenses per boe were reduced 9% to $9.46/boe for 2016, as compared to $10.36/boe for 2015, and transportation expenses per boe decreased 35% to $1.11/boe in 2016, as compared to $1.72/boe in 2015. These reductions reflect a combination of a lower overall cost structure combined with the lower cost Eagle Ford assets representing a larger percentage of our total production. General and administrative expenses were reduced to $50.9 million in 2016 from $59.4 million in 2015.

Throughout 2016, we targeted our capital expenditures to approximate FFO in order to minimize additional bank borrowings. For 2016, our FFO totaled $276.3 million compared to capital expenditures of $224.8 million. Capital expenditures were focused on our Eagle Ford assets where we invested $198.9 million to drill 127 (36.9 net) wells and commenced production from 123 (36.3 net) wells. In Canada, capital expenditures were limited to $25.9 million with drilling limited to 15 (4.0 net) wells mainly focused on non-operated lands in Lloydminster.

In Q4/2016, we entered an agreement to acquire assets in the Peace River area of Alberta for approximately $65 million and also completed a $115 million equity financing to fund the acquisition. The equity financing closed on December 12, 2016 with 21.9 million

shares being issued for proceeds of $109.9 million (net of issue costs). The acquisition closed subsequent to year end on January 20, 2017.

We generated FFO of $276.3 million ($1.30 per basic and diluted share) during 2016 compared to $516.4 million ($2.61 per basic and diluted share) in 2015. The decrease in FFO is primarily due to lower realized pricing, lower production volumes and lower realized hedging gains.

In 2016, our FFO exceeded our capital expenditures net of asset sales by $115 million. This, along with the proceeds from the equity financing and a decrease in the CAD/USD exchange rate, contributed to our net debt decreasing by $276 million from December 31, 2015 to $1.77 billion at December 31, 2016. We also had approximately $580 million of undrawn credit capacity and are in compliance with all of our financial covenants as at December 31, 2016.

RESULTS OF OPERATIONS

The Canadian division includes the heavy oil assets in Peace River and Lloydminster and the conventional oil and natural gas assets in Western Canada. The U.S. division includes the Eagle Ford assets in Texas.

Production

	Years Ended December 31					
	2016			2015		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**23,586**	**—**	**23,586**	34,974	—	34,974
Light oil and condensate	**1,407**	**19,970**	**21,377**	1,828	24,059	25,887
NGL	**1,274**	**8,075**	**9,349**	1,070	7,422	8,492
Total liquids (bbl/d)	**26,267**	**28,045**	**54,312**	37,872	31,481	69,353
Natural gas (mcf/d)	**40,015**	**51,167**	**91,182**	40,911	50,855	91,766
Total production (boe/d)	**32,936**	**36,573**	**69,509**	44,691	39,957	84,648
Production Mix						
Heavy oil	**72%**	**—%**	**34%**	79%	—%	41%
Light oil and condensate	**4%**	**55%**	**31%**	4%	61%	31%
NGL	**4%**	**22%**	**13%**	2%	19%	10%
Natural gas	**20%**	**23%**	**22%**	15%	20%	18%

Production for 2016 averaged 69,509 boe/d, an 18% decrease from 2015. U.S. production averaged 36,573 boe/d in 2016, an 8% decrease from 2015 as a result of decreased capital investment and the sale of approximately 1,000 boe/d of operated production in the Eagle Ford. Canadian production of 32,936 boe/d decreased 26%, or 11,755 boe/d, from 2015 with minimal capital investment along with low or negative margin production that was shut-in for part of 2016. The shut-in volumes reduced 2016 average production by approximately 2,400 boe/d.

Commodity Prices

The prices received for our crude oil and natural gas production directly impact our earnings, funds from operations and our financial position.

Crude Oil
Crude oil was extremely volatile during 2016 as the global over supply of crude oil combined with elevated inventory levels weighed on the price. In Q1/2016, WTI crude oil prices hit a 13-year low of US$26.21/bbl. During Q2/2016 and Q3/2016, prices were stabilized and averaged approximately US$45/bbl. On November 30, 2016, OPEC and non-OPEC countries agreed to production cuts which resulted in oil prices rising above US$50/bbl for the last part of 2016. WTI averaged US$49.29/bbl for Q4/2016, a 10% increase compared to Q3/2016. For 2016, WTI averaged US$43.33/bbl, representing an 11% decrease from the average WTI price of US$48.79/bbl for 2015.

The discount for Canadian heavy oil is measured by the Western Canadian Select ("WCS") price differential to WTI. For 2016, the WCS heavy oil differential averaged US$13.84/bbl, as compared to US$13.53/bbl for 2015. Over the past year, increased pipeline capacity from Canada to the U.S. Gulf Coast combined with lower overall production levels have helped to stabilize the WCS heavy oil differential.

Natural Gas

Natural gas prices have been driven lower during 2016 compared to 2015 mainly due to production levels exceeding demand. For 2016, the AECO natural gas price averaged $2.09/mcf, a decrease of $0.65/mcf or 24% compared to $2.74/mcf in 2015. The NYMEX natural gas price averagedUS$2.46/mmbtu during 2016, representing a decrease of US$0.20/mmbtu or 8% compared to US$2.66/mmbtu in 2015. AECO continues to trade at a significant discount to NYMEX due to the oversupply in Western Canada combined with pipeline constraints.

The following table compares selected benchmark prices and our average realized selling prices for the years ended December 31, 2016 and 2015.

	Years Ended December 31		
	2016	2015	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	**43.33**	48.79	(11)%
WTI oil (CAD$/bbl)	**57.44**	62.50	(8)%
WCS heavy oil (US$/bbl)[2]	**29.49**	35.26	(16)%
WCS heavy oil (CAD$/bbl)	**39.09**	45.17	(13)%
LLS oil (US$/bbl)[3]	**43.82**	51.50	(15)%
LLS oil (CAD$/bbl)	**58.08**	65.98	(12)%
CAD/USD average exchange rate	**1.3256**	1.2811	3 %
Edmonton par oil ($/bbl)	**53.01**	57.20	(7)%
AECO natural gas price ($/mcf)[4]	**2.09**	2.74	(24)%
NYMEX natural gas price (US$/mmbtu)[5]	**2.46**	2.66	(7)%

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.
(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Years Ended December 31					
	2016			2015		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Canadian heavy oil ($/bbl)[2]	**$ 26.46**	**$ —**	**$ 26.46**	$ 32.23	$ —	$ 32.23
Light oil and condensate ($/bbl)	**46.21**	**50.60**	**50.32**	52.52	55.99	55.75
NGL ($/bbl)	**17.77**	**17.06**	**17.16**	20.80	16.35	16.91
Natural gas ($/mcf)	**2.01**	**3.21**	**2.69**	2.59	3.47	3.08
Weighted average ($/boe)[2]	**$ 24.06**	**$ 35.89**	**$ 30.29**	$ 30.24	$ 41.16	$ 35.40

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.
(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

Average Realized Sales Prices

During 2016, we realized $50.60/bbl for our U.S. light oil and condensate. This was down from $55.99/bbl or approximately 10% from 2015, which is slightly less than the 12% decrease in the LLS benchmark (expressed in Canadian dollars) over the same period. Reduced supply along with increased pipeline capacity have tightened the pricing differential between our realized U.S. light oil and condensate pricing to LLS during 2016 compared to 2015.

Our realized Canadian light oil and condensate price averaged $46.21/bbl for 2016 compared to $52.52/bbl for 2015. This represents a 12% decrease in 2016 which is higher than the 7% decrease in the benchmark Edmonton par price over the same period. Our Canadian realized price decreased slightly more than the benchmark when comparing 2016 to 2015 as a higher percentage of our Canadian light oil production in 2016 was comprised of medium grade crude which has a higher discount to the benchmark price.

In 2016, our realized heavy oil price was $26.46/bbl, a $5.77/bbl decrease from 2015. The decrease in our realized heavy oil price during 2016 is generally consistent with the decrease in the WCS benchmark price (expressed in Canadian dollars) of $6.08/bbl over the same period. Our heavy oil is generally sold at a fixed dollar differential to the benchmark price. Our realized price decreased slightly less than the benchmark as the volumes that were shut-in during part of 2016 had a higher discount to the benchmark price resulting in slightly better price realizations during 2016.

Our Canadian average realized natural gas price was $2.01/mcf for 2016, down 22% from the same period in 2015. The decrease in our realized prices during 2016 was consistent with the decrease in the AECO benchmark of 24% over the same period.

Our U.S. realized natural gas price was $3.21/mcf for 2016, down 7% from 2015 which is consistent with the decrease in the NYMEX benchmark of 7% over the same period.

For 2016, our realized NGL price was $17.16/bbl or 30% of WTI (expressed in Canadian dollars) compared to $16.91/bbl or 27% of WTI in 2015. The change in our realized price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes.

Gross Revenues

	Years Ended December 31					
	2016			2015		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil revenue						
Heavy oil	**$ 228,425**	**$ —**	**$ 228,425**	$ 411,386	$ —	$ 411,386
Light oil and condensate	**23,792**	**369,869**	**393,661**	35,044	491,700	526,744
NGL	**8,287**	**50,416**	**58,703**	8,121	44,286	52,407
Total liquids revenue	**260,504**	**420,285**	**680,789**	454,551	535,986	990,537
Natural gas revenue	**29,506**	**60,178**	**89,684**	38,723	64,334	103,057
Total oil and natural gas revenue	**290,010**	**480,463**	**770,473**	493,274	600,320	1,093,594
Heavy oil blending revenue	**9,622**	**—**	**9,622**	27,830	—	27,830
Total petroleum and natural gas revenues	**$ 299,632**	**$ 480,463**	**$ 780,095**	$ 521,104	$ 600,320	$ 1,121,424

Total oil and natural gas revenues for 2016 of $770.5 million decreased by $323.1 million or 30% from 2015 due to a combination of lower commodity prices and reduced production volumes. Oil and natural gas revenues per boe decreased 14% in 2016 compared to 2015, which accounted for $158 million of the reduction in oil and natural gas revenue year over year. The decrease in production accounts for the remaining $165 million difference in revenue from 2015. Oil and natural gas revenues of $480.5 million in the U.S. decreased $119.9 million from 2015 mainly due to the $5.27/boe decrease in oil and gas revenues per boe resulting from lower commodity prices. In Canada, oil and natural gas revenues for 2016 totaled $290.0 million, a $203.3 million decrease compared to 2015 due to lower production volumes and lower realized prices.

Heavy oil transported through pipelines requires blending to reduce its viscosity in order to meet pipeline specifications. The cost of blending diluent is recovered in the sale price of the blended product. Our heavy oil transported by rail does not require blending diluent. The purchases and sales of blending diluent are recorded as heavy oil blending expense and revenue, respectively. Heavy oil blending revenue of $9.6 million for 2016 decreased $18.2 million compared to 2015. This decrease is a result of lower heavy oil production in Canada combined with lower overall prices for diluent in 2016 compared to 2015.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues, or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of gross revenue. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2016 and 2015.

	Years Ended December 31					
	2016			2015		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 37,720**	**$ 140,396**	**$ 178,116**	$ 67,323	$ 174,102	$ 241,425
Average royalty rate[1]	**13.0%**	**29.2%**	**23.1%**	13.6%	29.0%	22.1%
Royalty rate per boe	**$ 3.13**	**$ 10.49**	**$ 7.00**	$ 4.13	$ 11.94	$ 7.81

(1) Average royalty rate excludes sales of heavy oil blending diluents and financial derivatives gain (loss).

Total royalties for 2016 of $178.1 million decreased by $63.3 million or 26%, from 2015, primarily due to the 29% decline in oil and natural gas revenues. Total royalties decreased less than revenues as the Eagle Ford, which has a higher royalty rate, represented approximately 62% of oil and natural gas revenues in 2016 compared to approximately 55% in 2015. Canadian royalties, which vary with price, decreased to 13.0% of oil and natural gas revenue for 2016 compared to 13.6% of revenue in 2015, primarily due to lower commodity prices. The royalty percentage on our U.S. assets does not vary with price and as a result the 2016 U.S. royalty rate has remained fairly consistent with the 2015 rate.

Operating Expense

	Years Ended December 31					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Operating expense	**$ 142,242**	**$ 98,463**	**$ 240,705**	$ 210,945	$ 109,242	$ 320,187
Operating expense per boe	**$ 11.80**	**$ 7.36**	**$ 9.46**	$ 12.93	$ 7.49	$ 10.36

(1) Operating expense related to the Eagle Ford assets includes transportation expense.

Operating expense of $240.7 million for 2016 decreased by $79.5 million or 25%, compared to 2015. Overall operating costs are down as production has decreased in 2016 compared to 2015. Operating expense are also down on a unit of production basis with operating costs decreasing to $9.46/boe for 2016, compared to $10.36/boe for 2015 representing a 9% decrease. In Canada, the impact of our cost savings initiatives along with the benefit of shutting-in higher cost properties for part of 2016 resulted in lower operating expenses per unit of production for 2016 compared to 2015. Also, the lower cost Eagle Ford assets comprise a larger proportion of our overall volumes which has helped reduce our overall operating costs per boe.

U.S. operating expense of $98.5 million for 2016 decreased by $10.8 million compared to 2015 primarily due to the decrease in production. On a unit of production basis, U.S operating expenses for 2016 decreased slightly to $7.36/boe compared to $7.49/boe for 2015. On a U.S. dollar basis, operating expenses per boe decreased 5% in 2016 compared to 2015 but the Canadian dollar weakened against the U.S. dollar which partially mitigated the impact of the operating cost savings expressed in Canadian dollars.

Canadian operating expense of $142.2 million for 2016, decreased by $68.7 million or 33%, compared to 2015. The decrease is a result of lower production volumes combined with realized cost savings across all of our operations. On a per boe basis, Canadian operating expense was $11.80/boe for 2016 down 9% compared to $12.93/boe in 2015. The decrease in 2016 reflects the cost savings initiatives during the year combined with the impact of higher cost production being shut-in for part of 2016.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of heavy oil in Canada to pipeline and rail terminals. The following table compares our transportation expense for the years ended December 31, 2016 and 2015.

	Years Ended December 31					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Transportation expense	**$ 28,257**	**$ —**	**$ 28,257**	$ 53,127	$ —	$ 53,127
Transportation expense per boe	**$ 2.34**	**$ —**	**$ 1.11**	$ 3.26	$ —	$ 1.72

(1) Transportation expense related to the Eagle Ford assets have been included in operating expenses.

Transportation expense for 2016 totaled $28.3 million representing a decrease of 47% from $53.1 million in 2015. The decrease is due to lower heavy oil volumes being transported combined with the increased use of lower cost internal trucking. Transportation expense is also down on a per unit of production basis in 2016 to $2.34/boe in Canada compared to $3.26/boe in 2015. The use of lower cost internal trucking and shut-in volumes, which were generally subject to higher transportation charges explains the decrease from 2015.

Blending Expense

Blending expense for 2016 of $9.6 million decreased $18.2 million or 67% compared to $27.8 million for 2015. Consistent with the 65% decrease in heavy oil blending revenue, blending expense decreased due to lower volumes of blending diluent being used combined with the decrease in diluent prices in 2016 compared to 2015.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our funds from operations. Financial derivatives are managed at the corporate level and are not allocated between divisions. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price. Changes in the fair value of contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the year ended December 31, 2016 and 2015.

	Years Ended December 31		
($ thousands)	**2016**	2015	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 88,860**	$ 235,393	$ (146,533)
Natural gas	**8,069**	8,549	(480)
Foreign currency	**—**	(46,397)	46,397
Total	**$ 96,929**	$ 197,545	$ (100,616)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (122,249)**	$ (70,354)	$ (51,895)
Natural gas	**(17,887)**	968	(18,855)
Foreign currency	**—**	15,068	(15,068)
Interest and financing[1]	**—**	(498)	498
Total	**$ (140,136)**	$ (54,816)	$ (85,320)
Total financial derivatives gain (loss)			
Crude oil	**$ (33,389)**	$ 165,039	$ (198,428)
Natural gas	**(9,818)**	9,517	(19,335)
Foreign currency	**—**	(31,329)	31,329
Interest and financing	**—**	(498)	498
Total	**$ (43,207)**	$ 142,729	$ (185,936)

(1) Unrealized interest and financing derivatives gain (loss) includes the change in fair value of the call options embedded in our long-term notes.

The realized financial derivatives gain of $96.9 million for 2016 is a result of crude oil prices being at levels below those set in our fixed price contracts.

The unrealized financial derivatives loss of$140.1 million for 2016 is due to the realization, or reversal, of previous unrealized gains recorded at December 31, 2015 and from the increase in WTI futures price subsequent to December 31, 2015. At December 31, 2016, the fair value of our financial derivative contracts represent a net liability of $29.1 million compared to a net asset of $111.0 million at December 31, 2015.

For 2017, we have entered into hedges on approximately 51% of our net WTI exposure with 10% fixed at US$54.46/bbl and 41% hedged utilizing a 3-way option structure that provide us with downside price protection at approximately US$47/bbl and upside participation to approximately US$59/bbl. We have also entered into hedges on approximately 33% of our net WCS differential exposure and 57% of our net natural gas exposure.

Baytex had the following commodity financial derivative contracts as at March 6, 2017.

	Period	Volume	Price/Unit(1)	Index
Oil				
3-way option(2)	Jan 2017 to Dec 2017	14,500 bbl/d	US$58.60/US$47.17/US$37.24	WTI
Basis swap	Jan 2017 to Dec 2017	1,500 bbl/d	WTI less US$13.42	WCS
Fixed - Sell	Jan 2017 to Dec 2017	3,500 bbl/d	US$54.46	WTI
Fixed - Sell	Jan 2018 to Dec 2018	2,000 bbl/d	US$54.40	WTI
Basis swap(3)	Mar 2017 to Jun 2017	1,000 bbl/d	WTI less US$14.30	WCS
Basis swap(3)	Apr 2017 to Jun 2017	2,000 bbl/d	WTI less US$13.50	WCS
Basis swap(3)	Jul 2017 to Sep 2017	2,000 bbl/d	WTI less US$14.25	WCS
Natural Gas				
Fixed - Sell	Jan 2017 to Dec 2017	22,500 mmBtu/d	US$2.98	NYMEX
Fixed - Sell	Jan 2018 to Dec 2018	7,500 mmBtu/d	US$3.00	NYMEX
Fixed - Sell	Jan 2017 to Dec 2017	22,500 GJ/d	$2.85	AECO
Fixed - Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO

(1) Based on the weighted average price/unit for the remainder of the contract.
(2) 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$50/US$40 contract, Baytex receives WTI + US$10/bbl when WTI is at or below US$40/bbl; Baytex receives US$50/bbl when WTI is between US$40/bbl and US$50/bbl; Baytex receives the market price when WTI is between US$50/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.
(3) Contracts entered subsequent to December 31, 2016.

A full description of our financial derivatives can be found in note 18 to the consolidated financial statements.

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the periods indicated:

	Years Ended December 31					
	2016			2015		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**32,936**	**36,573**	**69,509**	44,691	39,957	84,648
Operating netback:						
Oil and natural gas revenues	**$ 24.06**	**$ 35.89**	**$ 30.29**	$ 30.24	$ 41.16	$ 35.40
Less:						
Royalties	**3.13**	**10.49**	**7.00**	4.13	11.94	7.81
Operating expenses	**11.80**	**7.36**	**9.46**	12.93	7.49	10.36
Transportation expenses	**2.34**	**—**	**1.11**	3.26	—	1.72
Operating netback	**$ 6.79**	**$ 18.04**	**$ 12.72**	$ 9.92	$ 21.73	$ 15.51
Realized financial derivatives gain	**—**	**—**	**3.81**	—	—	6.39
Operating netback after financial derivatives gain	**$ 6.79**	**$ 18.04**	**$ 16.53**	$ 9.92	$ 21.73	$ 21.90

Exploration and Evaluation Expense

Exploration and evaluation expense will vary from period to period depending on the expiry of leases and assessment of our exploration programs and assets. Exploration and evaluation expense was $6.0 million for 2016, as compared to $8.8 million for 2015. The decrease in expense in 2016 compared to 2015 is due to lower expiries of undeveloped land.

Depletion and Depreciation

	Years Ended December 31					
	2016			2015		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[1]	**$ 210,778**	**$ 294,854**	**$ 508,309**	$ 279,744	$ 377,847	$ 661,858
Depletion and depreciation per boe	**$ 17.49**	**$ 22.03**	**$ 20.04**	$ 17.15	$ 25.91	$ 21.42

(1) Total includes corporate depreciation.

Depletion and depreciation expense of $508.3 million for 2016, decreased by $153.5 million or 23% from 2015 mainly due to lower production. On a per boe basis, depletion and depreciation expense for 2016 was also down coming in at $20.04/boe, compared to $21.42/boe for 2015. The overall depletion rate has decreased in 2016 as we recorded $709.9 million of impairments on U.S. oil and gas properties in 2015 which reduced the depletable asset base along with the depletion rate per boe.

Impairment

In 2016, we recorded total impairment expense of $423.2 million. This impairment expense includes a $166.6 million impairment on our exploration and evaluation assets in the Eagle Ford, $230.0 million impairment on our oil and gas assets in Peace River and $26.6 million of impairments on an asset located near Lloydminster, which was subsequently disposed of in Q3/2016.

In 2016, we derecognized $166.6 million of exploration and evaluation assets in the Eagle Ford due to changes to our development plan, which resulted in possible reserves being reclassified to contingent resources. The derecognition of exploration and evaluation assets was recorded as an impairment charge.

In our Peace River CGU, we recorded a $230.0 million impairment expense on our oil and gas properties. Due to the low oil price environment, we did not engage in any reserves generating activity on our heavy oil assets in Canada, deferring all operated drilling activity, including development wells and stratigraphic test wells. This reduced level of activity resulted in limited reserves additions, which, when combined with production, economic factors and technical revisions, resulted in a 21% reduction in proved plus probable reserve volumes associated with our Peace River CGU, which resulted in an impairment. The recoverable amount of the Peace River CGU was determined based on their fair value less costs of disposal at December 31, 2016 using the discounted cash flows for proved and probable reserves. In computing the future cash flows of the assets, we made certain assumptions, most significantly about future commodity prices and the discount rate. We assumed a WTI price of approximately US$55.00/bbl in 2017, US$65.00/bbl in 2018 and US$70.00/bbl in 2019. It is possible that commodity prices in those years may be lower than the current estimate which could result in further impairments. Discount rates ranging from 10% to 15% before tax were applied to the cash flows.

In Q3/2016, we recorded a $26.6 million impairment expense in our Lloydminster CGU on assets that were reclassified from oil and gas properties to assets held for sale. The carrying value of the assets that were transferred to assets held for sale, exceeded their fair value, being the sale price, resulting in the impairment.

For 2015, we recorded an impairment expense totaling $1,038.6 million, which was comprised of a $992.9 million impairment on our Eagle Ford assets and $45.7 million impairment related to assets in our Lloydminster CGU. The impairment charge on our Eagle Ford assets were directly attributable to lower commodity prices. The Eagle Ford assets were originally recorded at their fair value at the time of acquisition in June 2014 when the WTI oil price was above US$100/bbl. Commodity prices declined in 2015 along with the future market prices which reduced the estimated future cash flows for our Eagle Ford assets below the carrying amount of the assets. The total impairment for 2015 on our Eagle Ford assets included $282.9 million of remaining goodwill associated with this acquisition along with $710.0 million related to oil and gas properties. In our Lloydminster CGU, we identified certain lands that we no longer anticipated the ability to access, develop and explore, therefore, we recorded an impairment charge of $45.7 million on these assets. The lands were subsequently disposed of in November 2015.

General and Administrative Expense

	Years Ended December 31		
($ thousands except for % and per boe)	**2016**	2015	Change
General and administrative expense	**$ 50,866**	$ 59,406	(14)%
General and administrative expense per boe	**$ 2.00**	$ 1.92	4 %

General and administrative ("G&A") expense for 2016 of $50.9 million decreased $8.5 million or 14% from $59.4 million in 2015. The decrease is attributable to reductions in staffing levels commensurate with lower activity levels combined with cost saving efforts. On a per boe basis, G&A expense increased 4% to $2.00/boe from $1.92/boe as production decreased 18% over the period compared to the 14% reduction in G&A expense.

Share-Based Compensation Expense

Compensation expense associated with the Share Award Incentive Plan is recognized in net income (loss) over the vesting period of the share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus.

Compensation expense related to the Share Award Incentive Plan was $13.9 million for 2016, compared to $24.6 million for 2015. For 2016, compensation expense decreased $10.7 million due to the lower fair value of share awards granted late in 2015 and early in 2016. This lower fair value is a result of a reduction in the Company's share price at grant date for the new grants compared to those issued prior to 2015.

During the year, the Company identified an immaterial error relating to share-based compensation expense in our previously issued financial statements. The estimated forfeiture rate was improperly applied to share awards that had previously vested and transferred to share capital, thereby understating share-based compensation expense. The Company concluded that the error is not material to the Company's previously filed financial statements and the corrected adjustments have been applied to the comparative financial information in the consolidated financial statements.

For the year ended December 31, 2015 an adjustment of $9.2 million of share-based compensation has been recorded resulting in a revised expense of $24.6 million. Net loss per share (basic and diluted) increased by $0.05 to $5.77 per share from $5.72 per share for the year ended December 31, 2015. For the year ended December 31, 2014 an additional $4.2 million of share-based compensation has been recorded resulting in a revised expense of $31.7 million. Net loss per share (basic and diluted) increased by $0.03 to $0.92 from $0.89 per share for the year ended December 31, 2014. As at December 31, 2014, both deficit and contributed surplus were increased by $8.2 million. A summary of the adjustments are disclosed in note 13 to the consolidated financial statements.

Financing and Interest Expense

Financing and interest expense includes interest on our bank loan and long-term notes, non-cash financing costs and the accretion on our asset retirement obligations.

Financing and interest expense increased slightly to $114.2 million for 2016, compared to $111.7 million in 2015. This increase relates to the interest on our U.S. dollar denominated long-term notes. The Canadian dollar was weaker against the U.S. dollar during 2016 averaging 1.3256 CAD/USD, as compared to 2015 when the exchange rate averaged 1.2811 CAD/USD, which increased the expense during 2016.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan are translated to Canadian dollars on the balance sheet date. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in the Canadian operations.

	Years Ended December 31		
($ thousands except for % and exchange rates)	**2016**	2015	Change
Unrealized foreign exchange loss (gain)	**$ (41,436)**	$ 213,999	(119)%
Realized foreign exchange (gain)	**(1,242)**	(3,286)	(62)%
Foreign exchange loss (gain)	**$ (42,678)**	$ 210,713	(120)%
CAD/USD exchange rates:			
At beginning of period	**1.3840**	1.1601	
At end of period	**1.3427**	1.3840	

The Company recorded an unrealized foreign exchange gain of$41.4 million for 2016 as the Canadian dollar at December 31, 2016 strengthened against the U.S. dollar with a CAD/USD exchange rate of 1.3427 compared to the exchange rate of 1.3840 at December 31, 2015.

The Company realizes foreign exchange gains and losses from day-to-day U.S. dollar denominated transactions in its Canadian entities. For 2016, the Company recorded realized foreign exchange gains of $1.2 million, compared to gains of $3.3 million for 2015.

Other Income/Expense

For 2016, we have other expense of$8.2 million, compared to other income of$8.4 million for 2015. In 2016, we entered into agreements to sublease a portion of our firm transportation commitment and a portion of our office space at a loss. We recorded an expense of $6.7 million on the transportation agreement and $3.5 million on our office space. These expenses represent the difference between the minimum future payments that we are required to make and the estimated recoveries. This was offset by miscellaneous income of $2.0 million. In 2015, we subleased our firm transportation commitment at a higher rate than our contract rate and recognized other income of $8.4 million.

Income Taxes

	Years Ended December 31		
($ thousands)	**2016**	2015	Change
Current income tax (recovery) expense	**$ (8,042)**	$ 8,907	$ (16,949)
Deferred income tax (recovery)	**(264,561)**	(353,053)	88,492
Total income tax (recovery)	**$ (272,603)**	$ (344,146)	$ 71,543

In 2016, available tax deductions exceeded taxable income which allowed the Company to recover a portion of the prior year current income tax expense. For 2016, this resulted in a current income tax recovery of $8.0 million, an increase of$16.9 million over the current income tax expense of$8.9 million for 2015.

The 2016 deferred income tax recovery of $264.6 million decreased $88.5 million from $353.1 million in 2015. The decrease during 2016 compared to 2015 is due to the higher impairment expense on oil and gas properties recorded in 2015, partially offset by an increase in unrealized loss on financial derivatives and a decrease in the amount of tax pool claims required to shelter the lower taxable income.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments follow the previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

We remain confident that the tax filings of the affected entities are correct and are vigorously defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

In September 2016, we filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of the CRA; a process that we estimate could take up to two years. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the “Losses”). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available for “carry back” to the years 2012 through 2015.

Tax Pools

The Company has Canadian and U.S. tax pools, which are available to reduce future taxable income. Our cash income tax liability is dependent upon many factors, including the prices at which we sell our production, available income tax deductions and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and currently enacted tax laws in Canada and the United States, we do not expect to pay material amounts of cash income taxes prior to 2020.

The income tax pools detailed below are deductible at various rates as prescribed by law:

($ thousands)	**December 31, 2016**	December 31, 2015
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 198,525**	$ 231,168
Canadian development expenditures	**250,239**	347,014
Canadian exploration expenditures	**210**	94
Undepreciated capital costs	**256,549**	339,635
Non-capital losses	**151,959**	63,064
Financing costs and other	**69,025**	84,734
Total Canadian tax pools	**$ 926,507**	$ 1,065,709
U.S. Tax Pools		
Depletion	**$ 297,252**	$ 383,551
Intangible drilling costs	**388,727**	439,380
Tangibles	**136,969**	149,971
Non-capital losses	**1,039,782**	1,046,951
Other	**201,896**	65,669
Total U.S. tax pools	**$ 2,064,626**	$ 2,085,522

Net Income (Loss) and Funds from Operations

Net loss for 2016 totaled $485.2 million ($2.29 per basic and diluted share) compared to a net loss of $1,142.9 million ($5.77 per basic and diluted share) for 2015. Funds from operations for 2016 totaled $276.3 million ($1.30 per basic and diluted share) as compared to $516.4 million ($2.61 per basic and diluted share) for 2015. The components of the change in net income (loss) and funds from operations from 2015 to 2016 are detailed in the following table:

	Years Ended December 31	
($ thousands)	**Net income (loss)**	**Funds from operations**
2015	**$ (1,142,880)**	**$ 516,417**
Increase (decrease) in revenues		
Revenue, net of royalties	(278,020)	(278,020)
(Increase) decrease in expenses		
Operating	79,482	79,482
Transportation	24,870	24,870
Blending	18,208	18,208
General and administrative	8,540	8,540
Exploration and evaluation	2,799	—
Depletion and depreciation	153,549	—
Impairment	615,378	—
Share-based compensation	10,691	—
Financing and interest	(2,539)	(281)
Financial derivatives	(185,936)	(100,616)
Foreign exchange	253,391	(2,044)
Other[1][2]	28,826	(7,254)
Current income tax	16,949	16,949
Deferred income tax	(88,492)	—
2016	**$ (485,184)**	**$ 276,251**

(1) For net income (loss), "other" includes gain (loss) on disposition and other income/expense.
(2) For funds from operations, "other" includes the cash component of other income/expense and payments on onerous contracts.

Dividends

In response to the prolonged low price commodity environment and in an effort to preserve liquidity, we suspended our monthly dividend beginning in September of 2015. During 2015, we declared monthly dividends of $0.10 per common share from January to August totaling $0.80 per common share. In total, $96.6 million of the dividends were paid in cash and $57.3 million were settled by issuing 4,707,914 common shares under our dividend reinvestment plan during 2015. No dividends have been declared or paid subsequent to September 2015.

Other Comprehensive Income (Loss)

Other comprehensive income (loss) is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $75.5 million foreign currency translation loss for 2016 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the strengthening of the Canadian dollar against the U.S. dollar at December 31, 2016 (1.3427 CAD/USD) as compared to December 31, 2015 (1.3840 CAD/USD).

Capital Expenditures

Capital expenditures for the years ended December 31, 2016 and 2015 are summarized as follows:

	Years Ended December 31					
	2016			2015		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land	**$ 4,053**	**$ 6,098**	**$ 10,151**	$ 4,704	$ 276	$ 4,980
Seismic	**638**	**—**	**638**	300	—	300
Drilling, completion and equipping	**13,618**	**178,412**	**192,030**	45,937	420,559	466,496
Facilities	**7,564**	**14,400**	**21,964**	20,309	28,954	49,263
Total exploration and development	**$ 25,873**	**$ 198,910**	**$ 224,783**	$ 71,250	$ 449,789	$ 521,039
Total acquisitions, net of proceeds from divestitures	**(8,883)**	**(54,237)**	**(63,120)**	1,641	7	1,648
Total oil and natural gas expenditures	**$ 16,990**	**$ 144,673**	**$ 161,663**	$ 72,891	$ 449,796	$ 522,687
Wells drilled (net)	**4.0**	**36.9**	**40.9**	31.4	50.2	81.6

2016 capital expenditures totaled $224.8 million as compared to $521.0 million in 2015. Capital spending has been focused on our Eagle Ford assets which accounted for 88% of 2016 capital expenditures. In the U.S., capital spending decreased to $198.9 million in 2016 from $449.8 million in 2015 due to lower activity levels associated with lower commodity prices combined with significant cost savings achieved on our Eagle Ford capital program. We drilled 127 (36.9 net) wells in the Eagle Ford in 2016 compared to 188 (50.2 net) wells in 2015. Total costs in the Eagle Ford have continued to decrease with wells now being drilled, completed and equipped for approximately US$4.5 million per well as compared to US$6.2 million per well in 2015 representing a 28% decrease year over year. In Canada, all operated heavy oil drilling was deferred due to the low price environment. For 2016 we drilled 15 (4.0 net) wells and spent $25.9 million compared to 2015 when we drilled 40 (31.4 net) wells and spent $71.3 million.

On July 27, 2016, the Company disposed of its operated interest in certain Eagle Ford properties for proceeds of $54.2 million, which consisted of $11.8 million of oil and gas properties and $2.3 million of exploration and evaluation assets, resulting in a gain on disposition of $40.1 million.

During 2016, the Company disposed of certain non-core assets in Canada for total proceeds of $9.0 million. The divestitures consisted of $5.1 million of oil and gas properties and $0.1 million of exploration and evaluation assets, resulting in a gain on dispositions of $3.8 million.

LIQUIDITY, CAPITAL RESOURCES AND RISK MANAGEMENT

We regularly review our capital structure and liquidity sources to ensure that our capital resources will be sufficient to meet our on-going short, medium and long-term commitments. Specifically, we believe that our internally generated funds from operations and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures.

We regularly review our exposure to counterparties to ensure they have the financial capacity to honor outstanding obligations to us in the normal course of business and, in certain circumstances, we will seek enhanced credit protection from these counterparties.

The current commodity price environment has reduced our internally generated funds from operations. As a result, we have taken several steps to protect our liquidity, which included reducing our 2016 capital program by approximately 40% from our initial plans and working with our lending syndicate to secure our bank credit facilities. We also shut-in low or negative margin production for part of 2016 and sold non-core assets during the year for proceeds of $63.6 million that were applied to our credit facilities. On December 12, 2016, we closed an equity financing and issued 21,907,500 common shares for aggregate gross proceeds of approximately $115 million. The net proceeds, after issuance costs, of approximately $109.9 million were applied to our credit facilities and subsequently used to fund the acquisition of assets in the Peace River area of Alberta for approximately $65 million on January 20, 2017.

If commodity prices decline from current levels, we may need to make additional changes to our capital program. A sustained low price environment could lead to a default of certain financial covenants, which could impact our ability to borrow under existing credit facilities or obtain new financing. It could also restrict our ability to pay future dividends or sell assets and may result in our debt becoming immediately due and payable. Should our internally generated funds from operations be insufficient to fund the capital expenditures required to maintain operations, we may draw additional funds from our current credit facilities or we may consider seeking additional capital in the form of debt or equity. There is also no certainty that any of the additional sources of capital would be available when required.

At December 31, 2016, net debt was $1,773.5 million, as compared to $2,049.9 million at December 31, 2015, representing a decrease of $276.4 million. Funds from operations for 2016 exceeded capital spending by $51.5 million which reduced net debt. We also applied the proceeds of $63.6 million from non-core asset sales along with the $109.9 million from the equity financing late in 2016 to reduce our debt levels. The strengthening Canadian dollar against the U.S. dollar at December 31, 2016 compared to December 31, 2015 reduced the carrying value of our U.S. dollar denominated long-term notes and bank loans further reducing our net debt.

Bank Loan

On March 31, 2016, we amended our credit facilities to provide us with increased financial flexibility. The amendments included reducing our credit facilities

to US$575 million, granting our banking syndicate first priority security over our assets and restructuring our financial covenants. The amended revolving extendible secured credit facilities are comprised of a US$25 million operating loan and a US$350 million syndicated loan and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants as detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. We may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). The agreement relating to the Revolving Facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts - Credit agreements" on April 13, 2016).

The weighted average interest rate on the credit facilities for 2016 was3.5%, as compared to 4.2% for 2015.

Covenants

On March 31, 2016, we amended our credit facilities and restructured the financial covenants applicable to the Revolving Facilities. The following table summarizes the financial covenants contained in the amended credit agreement and our compliance therewith as at December 31, 2016.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at December 31, 2016**	**December 31, 2016 to March 31, 2018**	**June 30, 2018 to September 30, 2018**	**December 31, 2018**	**Thereafter**
Senior Secured Debt [(1)] to Bank EBITDA [(2)] (Maximum Ratio)	0.6:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage [(3)] (Minimum Ratio)	3.6:1.00	1.25:1.00	1.50:1.00	1.75:1.00	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2016, our Senior Secured Debt totaled $204 million.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income (loss) for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2016 was $373 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2016 were $104 million.

If we exceed or breach any of the covenants under the Revolving Facilities or our long-term notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to our shareholders.

Long-Term Notes

We have five series of long-term notes outstanding that total$1.58 billion as at December 31, 2016. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at December 31, 2016, the fixed charge coverage ratio was 3.6:1.00.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. As of February 17, 2016, these notes are redeemable at our option, in whole or in part, at specified redemption prices.

On July 19, 2012, we issued $300 million principal amount of senior unsecured notes bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. These notes are redeemable at our option, in whole or in part, commencing on July 19, 2017 at specified redemption prices.

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 (the "2021 Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "2024 Notes"). The 2021 Notes and the 2024 Notes pay interest semi-annually and are redeemable at our 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 specified redemption prices.

Pursuant to the acquisition of Aurora Oil & Gas Limited ("Aurora"), on June 11, 2014, we assumed all of Aurora's existing senior unsecured notes and then purchased and cancelled approximately 98% of the outstanding notes. On February 27, 2015, we redeemed one tranche of the remaining Aurora notes at a price of US$8.3 million plus accrued interest. As of April 1, 2016, the remaining Aurora notes (US$6.4 million principal amount) are redeemable at our option, in whole or in part, at specified redemption prices.

Financial Instruments

As part of our normal operations, we are exposed to a number of financial risks, including liquidity risk, credit risk and market risk. Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with financial liabilities. We manage liquidity risk through cash and debt management. Credit risk is the risk that a counterparty to a financial asset will default, resulting in the Company incurring a loss. Credit risk is managed by entering into sales contracts with creditworthy entities and reviewing our exposure to individual entities on a regular basis. Market risk is the risk that the fair value of future cash flows will fluctuate due to movements in market prices, and is comprised of foreign currency risk, interest rate risk and commodity price risk. Market risk is partially mitigated through a series of derivative contracts intended to particularly reduce the volatility in our funds from operations.

A summary of the risk management contracts in place as atDecember 31, 2016 and the accounting treatment thereof is disclosed in note 18 to the consolidated financial statements.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. In Q4/2016, we entered an agreement to acquire assets in the Peace River area of Alberta for approximately $65 million and completed an equity financing for approximately $115 million to fund the acquisition. The financing closed on December 12, 2016 and we issued 21,907,500 common shares for total proceeds of $109.9 million (net of issue costs). We also issued 958,516 common shares pursuant to our share-based compensation program during the year. As at March 1, 2017, we had 234,204,090 common shares and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our

funds from operations in an ongoing manner. A significant portion of these obligations will be funded by funds from operations. These obligations as of December 31, 2016 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 112,973**	$ 112,973	$ —	$ —	$ —
Bank loan[1] [2]	**191,286**	—	191,286	—	—
Long-term notes[2]	**1,584,158**	—	—	747,078	837,080
Interest on long-term notes[3]	**404,769**	64,325	128,650	127,847	83,947
Operating leases	**38,982**	8,164	15,511	12,679	2,628
Processing agreements	**48,833**	9,631	11,130	9,043	19,029
Transportation agreements	**59,172**	10,998	23,670	22,674	1,830
Total	**$ 2,440,173**	$ 206,091	$ 370,247	$ 919,321	$ 944,514

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be repaid on such date.
(2) Principal amount of instruments.
(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

SELECTED ANNUAL INFORMATION

($ thousands, except per common share amounts)	**2016**	2015	2014
Revenues, net of royalties	**$ 601,979**	$ 879,999	$ 1,529,897
Net income (loss)	**$ (485,184)**	$ (1,142,880)	$ (136,998)
Per common share - basic	**$ (2.29)**	$ (5.77)	$ (0.92)
Per common share - diluted	**$ (2.29)**	$ (5.77)	$ (0.92)
Total assets	**$ 4,594,085**	$ 5,488,498	$ 6,230,596
Total bank loan and long-term notes	**$ 1,754,070**	$ 1,854,929	$ 2,062,344
Cash dividends or distributions declared per common share	**$ —**	$ 0.80	$ 2.64
Average wellhead prices, net of blending costs ($/boe)	**$ 30.29**	$ 35.40	$ 66.54
Total production (boe/d)	**69,509**	84,648	78,395

QUARTERLY FINANCIAL INFORMATION

	2016				2015			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**233,116**	197,648	195,733	153,598	229,361	265,876	342,802	283,384
Net income (loss)	**(359,424)**	(39,430)	(86,937)	607	(419,175)	(519,247)	(27,096)	(177,362)
Per common share - basic	**(1.66)**	(0.19)	(0.41)	—	(1.99)	(2.50)	(0.13)	(1.05)
Per common share - diluted	**(1.66)**	(0.19)	(0.41)	—	(1.99)	(2.50)	(0.13)	(1.05)
Funds from operations	**77,239**	72,106	81,261	45,645	93,095	105,052	158,049	160,221
Per common share - basic	**0.36**	0.34	0.39	0.22	0.44	0.51	0.77	0.95
Per common share - diluted	**0.36**	0.34	0.39	0.22	0.44	0.51	0.77	0.95
Exploration and development	**68,029**	39,579	35,490	81,685	140,796	126,804	106,010	147,429
Canada	**12,151**	6,120	2,747	4,855	8,804	33,484	7,690	21,272
U.S.	**55,878**	33,459	32,743	76,830	131,992	93,320	98,320	126,157
Acquisitions, net of divestitures	**(322)**	(62,752)	(37)	(9)	(574)	(498)	1,170	1,550
Net debt	**1,773,541**	1,864,022	1,942,538	1,981,343	2,049,905	1,949,736	1,822,511	2,455,995
Total assets	**4,594,085**	4,995,876	5,089,280	5,197,913	5,488,498	5,893,759	6,189,417	6,419,922
Common shares outstanding	**233,449**	211,542	210,715	210,689	210,583	210,225	206,193	169,001
Daily production								
Total production (boe/d)	**65,136**	67,167	70,031	75,776	81,110	82,170	84,812	90,710
Canada (boe/d)	**31,704**	33,615	31,722	34,709	40,826	43,229	45,264	49,634
U.S. (boe/d)	**33,432**	33,552	38,309	41,067	40,284	38,941	39,548	41,076
Benchmark prices								
WTI oil (US$/bbl)	**49.29**	44.94	45.60	33.45	42.18	46.43	57.94	48.64
WCS heavy (US$/bbl)	**34.97**	31.44	32.29	19.22	27.69	33.13	46.35	33.91
CAD/USD avg exchange rate	**1.3339**	1.3051	1.2885	1.3748	1.3353	1.3094	1.2294	1.2308
AECO gas ($/mcf)	**2.81**	2.20	1.25	2.11	2.65	2.70	2.67	2.95
NYMEX gas (US$/mmbtu)	**2.98**	2.81	1.95	2.09	2.27	2.77	2.64	2.98
Sales price ($/boe)	**38.16**	31.73	30.52	21.93	30.03	34.59	43.34	33.54
Royalties ($/boe)	**9.28**	7.37	6.65	5.02	6.61	7.61	10.10	6.95
Operating expense ($/boe)	**9.96**	9.07	8.67	10.11	9.76	10.25	10.64	10.75
Transportation expense ($/boe)	**1.30**	1.38	0.81	0.98	1.45	1.52	1.94	1.95
Operating netback ($/boe)	**17.62**	13.91	14.39	5.82	12.21	15.21	20.66	13.89
Financial derivatives gain ($/boe)	**1.62**	3.04	3.74	6.47	4.09	3.33	5.19	12.48
Operating netback after financial derivatives ($/boe)	**19.24**	16.95	18.13	12.29	16.30	18.54	25.85	26.37

Our operating results over the last eight quarters have been consistent with our expectations and have varied primarily in response to the changes in oil prices. Oil prices have been at multi-year lows in the last eight quarters as the WTI oil price averaged less than US$50/bbl for seven out of the last eight quarters with a low of US$33.45/bbl in Q1/2016. Production has declined since Q1/2015 with reduced capital spending over the last two years in response to the lower price environment. Production in Canada has declined more than our U.S. production as there have been no operated heavy oil wells drilled in Canada since Q3/2015. Capital expenditures have been directed primarily to our Eagle Ford assets over the last two years as these assets generate our highest netbacks and highest rates of return. FFO has decreased coinciding with the declining oil price and lower production. Despite the lower FFO, our net debt has decreased to $1.8 billion in Q4/2016 down from $2.5 billion in Q1/2015. Over the last two years we have completed two equity financings raising gross proceeds of $633 million in Q2/2015 and $115 million in Q4/2016. In addition, we disposed of our operated assets in the Eagle Ford for proceeds of $54 million in Q3/2016 and sold other non-core assets for proceeds of approximately $9 million. Total assets have decreased from $6.4 billion in Q1/2015 to $4.6 billion in Q4/2016. Over the last two years the Company has recorded total impairment losses of $1.5 billion primarily related to the reduction in oil prices. These impairments have reduced the carrying value of our assets.

FOURTH QUARTER OF 2016

Our operating results for the fourth quarter were consistent with our expectations. Production averaged 65,136 boe/d in Q4/2016, as compared to 67,167 boe/d in Q3/2016 which resulted in annual average production of 69,509 boe/d, in line with our production guidance range of 69,000 to 70,000 boe/d.

In the Eagle Ford, production was stable during the fourth quarter, averaging 33,432 boe/d as compared to 33,552 boe/d in Q3/2016. During the fourth quarter, drilling activity increased as we averaged 3-4 drilling rigs and 1-2 completion crew on our lands, with two additional rigs being added by the end of the quarter. In Canada, production averaged 31,704 boe/d as compared to 33,615 boe/d in Q3/2016. Canadian production has decreased as we continued to limit capital expenditures on our Canadian assets during the fourth quarter due to the low oil price.

Capital expenditures for exploration and development activities totaled $68.0 million in Q4/2016 and $224.8 million for full-year 2016, in line with our guidance range of $200-225 million. In the Eagle Ford, we participated in the drilling of 27 (7.4 net) wells and placed 39 (11.6 net) wells on stream during Q4/2016. We have continued to realize cost reduction with wells being drilled, completed and equipped for approximately US$4.5 million per well in Q4/2016, down 20% from approximately US$5.6 million per well in Q1/2016. In Canada, we participated in the drilling of 14 (2.98 net) non-operated vertical wells at Lindbergh during Q4/2016.

In Q4/2016, we entered an agreement to acquire assets in the Peace River area of Alberta for approximately $65 million and also completed a $115 million equity financing to fund the acquisition. The equity financing closed on December 12, 2016 with 21.9 million shares issued for proceeds of $109.9 million (net of issue costs). The Peace River acquisition closed subsequent to year end on January 20, 2017.

We generated FFO of $77.2 million ($0.36 per share) in Q4/2016, compared to $72.1 million ($0.34 per share) in Q3/2016. The increase in FFO was primarily driven by a higher oil price which averaged US$49.29/bbl in Q4/2016 compared to US$44.94/bbl in Q3/2016. The oil price increased to more than US$50/bbl in December of 2016 after OPEC and non-OPEC countries announced their intentions to cut production levels on November 30, 2016. The higher oil prices increased oil and natural gas revenue for Q4/2016 by $33 million to $229 million, up from $196 million in Q3/2016. This was offset by higher royalties, higher operating expense and lower financial derivative gains which reduced FFO, contributing to the $5 million overall increase in FFO from Q3/2016.

Operating netback per boe increased to $17.62/boe in Q4/2016 compared to $13.91/boe in Q3/2016. The increase in netback per boe is directly attributable to higher oil prices which resulted in higher oil and gas revenues per boe of $38.16/boe in Q4/2016 compared to $31.73/boe in Q3/2016. The increased revenue per boe was slightly offset by higher royalty rates and higher operating costs per boe in Q4/2016 compared to Q3/2016. Royalty rates increased to 24.3% of revenue in Q4/2016 from 23.2% of revenue in Q3/2016 due to higher pricing and minor prior period adjustments. Operating expense averaged $9.96/boe in Q4/2016 up from $9.07/boe in Q3/2016. In Canada, operating expense increased to $13.10/boe in Q4/2016 from $12.32/boe in Q3/2016 with increased maintenance and the effect of fixed costs on lower production volumes. In the U.S., operating expense increased to $6.98/boe in Q4/2016 from $5.82/boe in Q3/2016 due to minor prior period adjustments and foreign exchange as the CAD/USD exchange rate increased.

We recorded a net loss in Q4/2016 of $359.4 million ($1.66 per share) compared to a net loss of $39.4 million ($0.19 per share) in Q3/2015. The net loss in the quarter is largely attributable to impairment charges of $396.6 million. In Q4/2016, we recorded an impairment charge of $166.6 million on our exploration and evaluation assets in the Eagle Ford along with a $230.0 million impairment charge on our oil and gas properties in Peace River.

In Q4/2016, our FFO exceeded our capital expenditures by $9.2 million. This along with the proceeds from the equity financing contributed to our net debt decreasing by $90.5 million from Q3/2016. As at December 31, 2016 our net debt was $1.77 billion and we had approximately $580 million of undrawn credit capacity on our revolving credit facilities. We were also in compliance with all of our financial covenants as at December 31, 2016.

The following table provides select operating results for Q4/2016.

	Three Months Ended December 31					
	2016			2015		
($ thousands, except as noted)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Heavy oil (bbl/d)	**22,982**	**—**	**22,982**	31,733	—	31,733
Light oil and condensate (bbl/d)	**1,281**	**18,882**	**20,163**	1,600	23,330	24,930
NGL (bbl/d)	**1,307**	**7,012**	**8,319**	973	8,023	8,996
Natural gas (mcf/d)	**36,804**	**45,228**	**82,032**	39,122	53,586	92,708
Total production (boe/d)	**31,704**	**33,432**	**65,136**	40,826	40,284	81,110
Baytex Average Sales Prices						
Canadian heavy oil ($/bbl)[1]	**$ 34.33**	**$ —**	**$ 34.33**	$ 24.41	$ —	$ 24.41
Light oil and condensate ($/bbl)	**55.16**	**60.45**	**60.12**	47.84	50.33	50.17
NGL ($/bbl)	**18.50**	**23.41**	**22.64**	19.93	16.90	17.23
Natural gas ($/mcf)	**2.78**	**4.28**	**3.61**	2.36	3.05	2.76
Weighted average ($/boe)[2]	**$ 31.10**	**$ 44.84**	**$ 38.16**	$ 23.59	$ 36.56	$ 30.03
Operating netback ($/boe)						
Oil and natural gas revenues	**$ 31.10**	**$ 44.84**	**$ 38.16**	$ 23.59	$ 36.56	$ 30.03
Less:						
Royalties	**4.82**	**13.52**	**9.28**	2.72	10.56	6.61
Operating expenses	**13.10**	**6.98**	**9.96**	12.27	7.23	9.76
Transportation expenses	**2.67**	**—**	**1.30**	2.87	—	1.45
Operating netback	**$ 10.51**	**$ 24.34**	**$ 17.62**	$ 5.73	$ 18.77	$ 12.21
Financial derivatives gain	**$ —**	**$ —**	**$ 1.62**	$ —	$ —	$ 4.09
Operating netback after financial derivatives	**$ 10.51**	**$ 24.34**	**$ 19.24**	$ 5.73	$ 18.77	$ 16.30
Capital Expenditures						
Exploration and development	**$ 12,151**	**$ 55,878**	**$ 68,029**	$ 8,804	$ 131,992	$ 140,796
Acquisitions, net of divestitures	**$ (218)**	**$ (104)**	**$ (322)**	$ (593)	$ 19	$ (574)

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in the table excludes the impact of financial derivatives.
(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

2017 GUIDANCE

In Canada, we have initiated an active first quarter drilling program in 2017 after limited activity over the past two years. In the Eagle Ford, we expect to maintain a consistent pace of development on our lands throughout 2017. We have designed our 2017 budget to be flexible should we continue to experience a volatile commodity price environment.

Our 2017 capital budget currently reflects a range of $300 to $350 million, which is designed to generate average annual production of 66,000 to 70,000 boe/d. For the full-year, approximately 70% of our planned capital expenditures will be directed to our Eagle Ford operations. The balance of the spending will be in Canada, largely toward our heavy oil assets at Peace River and Lloydminster. Our 2017 capital budget will be heavily weighted to drilling and completion activities (approximately 89%) with the balance for facilities (approximately 10%) and land and seismic (approximately 1%).

In the Eagle Ford, we expect to have four to five drilling rigs and two completion crews working on our lands, up from two to three rigs in the fourth quarter of 2016. At this pace of development, we expect to bring approximately 34 net wells on production in 2017. Our costs in the Eagle Ford continue to decrease with wells now being drilled, completed and equipped for approximately US$4.5 million.

In Canada, after two years of reduced activity and declining production, we are planning an active drilling program designed to stabilize production and ultimately, to position for growth. At Peace River, our capital budget includes drilling 11 net multi-lateral horizontal wells and 8 net stratigraphic wells. At Lloydminster, we plan to drill 52 net wells, of which approximately 55% will be horizontal wells. At Pembina, we expect to drill 2 net natural gas wells. Based on the mid-point of our 2017 annual average production guidance range of 68,000 boe/d, our production is expected to be equally split between Canada and the Eagle Ford. Our 2017 guidance includes an annual contribution of approximately 3,000 boe/d from our recently completed heavy oil acquisition at Peace River. Our production mix is forecast to be approximately 78% liquids (35% heavy oil, 31% light oil and condensate and 12% natural gas liquids) and 22% natural gas, based on a 6:1 natural gas-to-oil equivalency. Similar to 2016, we are targeting our 2017 capital expenditures to approximate funds from operations in order to minimize additional bank borrowings and will remain flexible.

2017 Guidance

Exploration and development capital	$300-$350 million
Production	66,000 to 70,000 boe/d
Expenses:	
Royalty rate	approximately 23%
Operating	$11.00-$12.00/boe
Transportation	$1.10-$1.30/boe
General and administrative	approximately $50 million or $2.00/boe
Interest	approximately $100 million or $4.00/boe

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2016, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES AND JUDGMENTS

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Accordingly, actual results can differ from those estimates. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, expenses, and disclosure of contingencies are discussed below.

Oil and Gas Activities

Reserves estimates can have a significant effect on net income (loss), assets and liabilities as a result of their impact on depletion, asset retirement obligations, asset impairments and business combinations. The estimation of reserves is a complex process requiring significant judgment. The Company's reserves are estimated annually by independent reserves evaluators and represent the estimated quantities of crude oil, natural gas and natural gas liquids which geological, geophysical and engineering data demonstrate a 50 percent or greater statistical probability of being recovered (total proved plus probable reserves) or a 10 percent or greater statistical probability of being recovered (total possible reserves). Changes to estimates such as forward price estimates, production costs, recovery rates and, accordingly, economic status of reserves may have a material impact on the consolidated financial statements.

The Company's capital assets are aggregated into cash-generating units based on management's judgment of their ability to generate largely independent cash flows. The cash-generating units are used to assess impairment and, accordingly, can directly impact the recoverability of the assets therein. Impairment of assets and groups of assets are calculated based on the higher of value-in-use calculations and fair value less cost to sell. These calculations require the use of estimates and assumptions on highly uncertain matters such as future commodity prices, royalty rates, effects of inflation and technology improvements on operating expenses, production profiles and the outlook of market supply-and-demand conditions for oil and natural gas products. Any changes to these estimates and assumptions could impact the carrying value of assets. Management applies judgment when it assesses internal and external factors to determine if indicators of impairment or indicators of impairment reversal exist.

The determination of technical feasibility and commercial viability of exploration and evaluation assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment.

Depletion and Depreciation
The amounts recorded for depletion of oil and gas properties are based on a unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the level of development required to produce the reserves. See "Oil and Gas Activities" above for discussion of estimates and judgments involved in reserve estimation.

Amounts recorded for depreciation are based on the estimated useful lives of depreciable assets which are reviewed by management at each reporting date.

Business Combinations
Business combinations are accounted for using the acquisition method of accounting. The determination of fair value of assets and liabilities acquired often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and exploration and evaluation assets acquired generally require the most judgment and include estimates of reserves acquired, forecast benchmark commodity prices and discount rates. Changes in any of the assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities and goodwill. Future net income (loss) can be affected as a result of changes in future depletion, depreciation, asset impairment or goodwill impairment.

Joint Control
Judgment is required to determine when the Company has joint control over a joint operation, which requires an assessment of the capital and operating activities of the projects undertaken with partners and when decisions in relation to those activities require unanimous consent.

Fair Value of Financial Instruments
Fair values of financial instruments, where active market quotes are not available, are estimated using the Company's assessment of available market inputs. These estimates may vary from the actual prices achieved upon settlement of the financial instruments.

Share-based Compensation
Compensation expense related to awards granted under the Company's Share Award Incentive Plan is dependent on estimated fair values, forfeiture rates and, for performance awards, a payout multiplier based on past performance. Compensation expense may fluctuate due to changes in management's estimates.

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

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

Income Taxes
Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and differing interpretations require management judgment. Income tax filings are subject to audits and re-assessments and changes in facts, circumstances and interpretations of the standards may result in a material change in the Company's provision for income taxes. As such, income taxes are subject to measurement uncertainty.

We employ individuals skilled in making such estimates and ensure those responsible have the most accurate information available. Further, approved budgets and prior period estimates are also reviewed and analyzed against actual results to ensure appropriate decisions are made for future estimates and outlooks. Actual results could differ materially if various assumptions or estimates do not turn out as expected.

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Revenue from Contracts with Customers

In April 2016, the International Accounting Standards Board (the "IASB") issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which will replace IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The standard also requires extensive new disclosures, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. We will adopt IFRS 15

on January 1, 2018 and are currently in the process of creating a plan to identify and review our various revenue streams and underlying contracts and assessing the impact on our consolidated financial statements.

Financial Instruments

In July 2014, the IASB issued IFRS 9 *Financial Instruments* which is intended to replace IAS 39 *Financial Instruments: Recognition and Measurement* The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. We currently do not apply hedge accounting to our derivative contracts nor do we intend to apply hedge accounting upon adoption of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. We will adopt IFRS 9 on January 1, 2018 and are currently evaluating its impact on our consolidated financial statements.

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income (loss). The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. We will adopt IFRS 16 on January 1, 2019 and are currently evaluating the impact of the standard on the consolidated financial statements.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2016, an evaluation was conducted of the effectiveness of our "disclosure controls and procedures" (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the "Exchange Act") and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our 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.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

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

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2016. The effectiveness of our internal control over financial reporting as of December 31, 2016 has been audited by KPMG LLP, as reflected in their report for 2016. No changes were made to our internal control over financial reporting during the year ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial results. Listed below is a description of these risk and uncertainties. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2016 under the "Risk Factors" section.

Volatility of Oil and Natural Gas Prices

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. If crude oil and natural gas prices decline or fail to increase from their current levels it could have a material adverse effect on our operations, 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 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.

Decreases to or a prolonged period of low 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 the shut-in of currently producing wells, a delay or cancellation of existing or future drilling, development or construction programs, unutilized long-term transportation commitments and a reduction in the value and amount of our reserves.

Our reserves as at December 31, 2016 are estimated using forecast prices and costs. These prices are above current market prices for crude oil and natural gas. 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 undeveloped 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 oil and natural gas forecast prices decline further, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

Debt Service and Refinancing

We are required to comply with covenants under the Revolving Facilities and our long-term notes. In the event that we do not comply with these covenants, our access to capital (including our ability to make borrowings under our Revolving Facilities) could be restricted or repayment could be required on an accelerated basis by our lenders.

Our existing Revolving Facilities and any replacement facilities may not provide sufficient liquidity. We currently have Revolving Facilities in the amount of US$575 million. The amounts available under our existing Revolving 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. There can be no assurance that the amount of our Revolving 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. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations. In the event that the Revolving Facilities are not extended before June 2019, indebtedness under the Revolving Facilities will be repayable at that time. In addition, we are required to repay the long-term notes on maturity. There is a risk that the Revolving Facilities will not be renewed for the same amount or on the same terms.

Access to Capital Markets

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, investor interest in the energy industry in general, 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.

Non-operating Agreements in the U.S.

Marathon Oil EF LLC ("Marathon Oil"), a wholly-owned subsidiary of Marathon Oil Corporation, is the operator 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 a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of 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 and development 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. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such operation.

Variations in Interest Rates

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 to the market price of our common shares.

Variations in Foreign Exchange Rates

World oil prices are quoted in U.S. 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. 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 our Revolving Facilities and a large portion of our long-term notes are denominated in U.S. dollars and the interest and principal 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.

Credit Risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flows and financial position.

Risk Management

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 risk management 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 due to the volatile commodity environment.

Reserve Estimates

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.

Additional Business Risks

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.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of federal, provincial and state legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation 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 legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Although we believe that we will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

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 to reduce GHG emissions by 17% from 2005 levels. Both governments also signed the Paris Agreement in December of 2015, which included a commitment to keep any increase in global temperatures below two degrees Celsius. Additionally, Canada pledged to reduce GHG emissions by 30% by 2030 from 2005 levels and the United States pledged to reduce GHG emissions by 26% to 28% by 2025 from 2005 levels.

The United States has not yet announced or enacted any mechanisms or legislation to implement the Paris Agreement. The Government of Canada has announced that it intends to implement a carbon tax in 2018 starting at $10/tonne rising by $10/tonne a year to $50/tonne by 2022. This federal carbon tax is intended to be implemented in concert with the Provinces and territories and would only be implemented in those Provinces and territories that do not have their own carbon tax.

The Province of Alberta announced and implemented a broad range of plans targeting GHG emissions, that include: a carbon levy of $20/tonne that became effective January 1, 2017 that will increase to $30/tonne in 2018; a cap on GHG emissions from the oil sands of 100 mega tonnes per year; and a plan to introduce regulations that will reduce methane emissions from oil and gas operations by 45% by 2025. 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. We expect a minimal increase in operating costs through internal trucking and supplier rate increases as a result of the implementation of the carbon levy for our Alberta properties.

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our ability to reduce the volatility in our funds from operations by utilizing financial derivative contracts; the percentage of our net exposure to WTI, the WCS differential and natural gas that is hedged for 2017; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; our expectation regarding the payment of cash income taxes prior to 2020; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; our belief that the amended credit facilities provide increased financial flexibility; the existence, operation and strategy of our risk management program; our capital budget for 2017; our annual average production rate for 2017; the breakdown of our 2017 capital budget by geographic area and expenditure type; our plan for developing our properties in 2017, including the number of rigs and completion crews in the Eagle Ford, the number of wells to be brought on production in the Eagle Ford, the cost to drill, complete and equip a well in the Eagle Ford, the number and type of wells to be drilled at Peace River, Lloydminster and Pembina; the geographic breakdown of our 2017 annual production and the production expected from our recently completed heavy oil acquisition at Peace River; our production mix for 2017; our target of funding our capital expenditures with funds from operations to minimize additional bank borrowings; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2017; and the effect that Alberta's carbon tax will have on our operating costs. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; 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; 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 Baytex 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: the volatility of oil and natural gas prices; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; 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; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; we may lose access to our information technology systems; risks associated with the ownership of our securities, including 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. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2016, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Exhibit 99.4

CERTIFICATION PURSUANT TO RULE 13a-14 OR 15d-14 OF THE SECURITIES EXCHANGE ACT OF 1934, AS ADOPTED PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, James L. Bowzer, certify that:

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

Dated: March 7, 2017 BAYTEX ENERGY CORP.

/s/ James L. Bowzer
Name: James L. Bowzer
Title: Chief Executive Officer

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 on Form 40-F of Baytex Energy Corp.;
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 periods 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.

Dated: March 7, 2017 BAYTEX ENERGY CORP.

/s/ *Rodney D. Gray*
Name: Rodney D. Gray
Title: Chief Financial Officer

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, 2016, 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.

Dated: March 7, 2017 BAYTEX ENERGY CORP.

/s/ *James L. Bowzer*
Name: James L. Bowzer
Title: Chief Executive Officer

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, 2016, 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.

Dated: March 7, 2017 BAYTEX ENERGY CORP.

/s/ *Rodney D. Gray*
Name: Rodney D. Gray
Title: Chief Financial Officer

Exhibit 99.8

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the registration statement (No. 333-171568) on Form S-8 and registration statement (No. 333-171866) on Form F-3 of Baytex Energy Corp. of our reports dated March 6, 2017, with respect to:

- the consolidated financial statements which comprise the consolidated statement of financial position as at December 31, 2016, the consolidated statements of income (loss) and comprehensive income (loss), changes in equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information; and

- the effectiveness of internal control over financial reporting as of December 31, 2016,

which reports appear in the December 31, 2016 annual report on Form 40-F of Baytex Energy Corp., and further consent to the use of such reports in such annual report on Form 40-F.

Our report with respect to the consolidated financial statements refers to our audit of the adjustments that were applied to revise the 2015 consolidated financial statements, as more fully described in Note 13 to the consolidated financial statements. However, we were not engaged to audit, review or apply any procedures to the 2015 consolidated financial statements other than with respect to such adjustments.

/s/ KPMG LLP

Chartered Professional Accountants, Chartered Accountants
March 7, 2017
Calgary, Canada

Exhibit 99.9

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-171568 on Form S-8 and Registration Statement No. 333-171866 on Form F-3 of Baytex Energy Corp. and subsidiaries ("Baytex") and to the use of our report dated March 2, 2016 relating to the consolidated financial statements of Baytex appearing in this Annual Report on Form 40-F of Baytex for the year ended December 31, 2016.

/s/ Deloitte LLP

Chartered Professional Accountants, Chartered Accountants
March 7, 2017
Calgary, Canada

Exhibit 99.10

CONSENT OF INDEPENDENT ENGINEERS

We refer to: (i) our report dated January 30, 2017 and effective December 31, 2016, 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, 2016)*"; (ii) our report dated February 23, 2017 and effective December 31, 2016, evaluating the proved, probable and, for the United States, possible 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, 2016*)"; (iii) our assessment dated February 22, 2017 and effective December 31, 2016, evaluating the contingent resources attributable to the Company in Canada, which is entitled "*Evaluation of the Contingent Resources of Baytex Energy Corp. in Canada* "; (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. 333-171568 on Form S-8 and No. 333-171866 on Form F-3 of the Company 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, 2016 dated March 7, 2017, 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/ *Cameron P. Six*

Cameron P. Six, P. Eng.
President, CEO and Director

Calgary, Alberta, Canada
March 7, 2017

Exhibit 99.11

CONSENT OF INDEPENDENT ENGINEERS

We refer to: (i) our report dated February 1, 2017 and effective December 31, 2016, evaluating the proved, probable and possible petroleum and natural gas reserves attributable to Baytex Energy Corp. and its affiliates (collectively, the "Company") located in the in the Eagle Ford area of Texas, 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, 2016*"; and (ii) our letter report dated February 10, 2017 and effective December 31, 2016, auditing the contingent resources attributable to the Company in the Eagle Ford area of Texas, which is entitled "*Estimated Future Contingent Resources and Income Attributable to Certain Leasehold Interests* "; (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. 333-171568 on Form S-8 and No. 333-171866 on Form F-3 of the Company 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, 2016 dated March 7, 2017, 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 7, 2017

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2016

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 Reserves 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, 2016 were as follows:

	Canada			United States			Total		
	Crude Oil & NGL	**Bitumen**	**Natural Gas**	**Crude Oil & NGL**	**Bitumen**	**Natural Gas**	**Crude Oil & NGL**	**Bitumen**	**Natural Gas**
	(mbbl)	(mbbl)	(mmcf)	(mbbl)	(mbbl)	(mmcf)	(mbbl)	(mbbl)	(mmcf)
Net proved reserves									
December 31, 2014	65,709	14,995	69,362	94,869	—	173,339	160,578	14,995	242,701
Revisions of previous estimates	(17,060)	(2,128)	(3,611)	(7,005)	—	(8,028)	(24,065)	(2,128)	(11,639)
Improved recovery	549	—	12	—	—	—	549	—	12
Purchases	788	—	—	—	—	—	788	—	—
Extensions and discoveries	628	—	2,460	12,620	—	24,457	13,248	—	26,917
Production	(10,419)	(811)	(12,640)	(8,471)	—	(13,701)	(18,890)	(811)	(26,341)
Sales of minerals in place	(920)	—	—	—	—	—	(920)	—	—
December 31, 2015	39,275	12,056	55,583	92,013	—	176,067	131,288	12,056	231,650
Revisions of previous estimates	(14,723)	(5,743)	31,357	(13,650)	—	(36,237)	(28,373)	(5,743)	(4,880)
Improved recovery	198	—	1	—	—	—	198	—	1
Purchases	22	—	—	—	—	—	22	—	—
Extensions and discoveries	33	—	53	14,727	—	27,018	14,760	—	27,071
Production	(7,453)	(555)	(13,070)	(7,553)	—	(13,810)	(15,006)	(555)	(26,880)
Sales of minerals in place	(670)	—	(1,850)	(313)	—	(224)	(983)	—	(2,074)
December 31, 2016	16,682	5,758	72,074	85,224	—	152,814	101,906	5,758	224,888
Net proved developed reserves									
End of year 2014	40,931	8,157	48,321	32,227	—	50,768	73,158	8,157	99,089
End of year 2015	26,449	7,422	37,264	31,790	—	58,498	58,239	7,422	95,762
End of year 2016	15,103	880	33,120	31,374	—	60,009	46,477	880	93,129

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 reserves and production volumes estimated by Baytex's independent reserves evaluators, Sproule Unconventional Limited and Ryder Scott Company, L.P. The methodology used in calculating our price and cost assumptions for the standardized measure of discounted future net cash flows for reserves 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 2016 and 2015.

	Commodity Pricing	
	2016	**2015**
WTI crude (US$/bbl)	$ 42.75	$ 50.28
Canadian Light Sweet (Cdn$/bbl)	$ 52.08	$ 58.81
Western Canadian Select (WCS)[(1)] (Cdn$/bbl)	$ 38.13	$ 46.83
AECO-C spot price (Cdn$/mmbtu)	$ 2.17	$ 2.68
Henry Hub (US$/mmbtu)	$ 2.55	$ 2.59
Exchange rate (US$/Cdn$)	0.7350	0.7870

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

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

	Canada		United States		Total	
(thousands of Canadian dollars)	**2016**	**2015**	**2016**	**2015**	**2016**	**2015**
Future cash inflows	$ 625,763	$ 1,764,415	$ 3,823,293	$ 4,534,031	$ 4,449,056	$ 6,298,446
Future production costs	(356,876)	(949,459)	(1,444,893)	(1,495,597)	(1,801,769)	(2,445,056)
Future development costs	(119,549)	(275,877)	(1,250,620)	(1,400,851)	(1,370,169)	(1,676,728)
Future income taxes	—	—	(17,018)	(12,147)	(17,018)	(12,147)
Future net cash flows	149,338	539,079	1,110,762	1,625,436	1,260,100	2,164,515
Deduct: 10% annual discount factor	(35,103)	(142,292)	(558,359)	(770,705)	(593,462)	(912,997)
Standardized measure	$ 114,235	$ 396,787	$ 552,403	$ 854,731	$ 666,638	$ 1,251,518

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

As at December 31, 2016 *(thousands of Canadian dollars)*		**Canada**		**United States**		**Total**
Balance, beginning of year	$	396,787	$	854,731	$	1,251,518
Sales, net of production costs		(110,048)		(241,604)		(351,652)
Net change in prices and production costs related to future production		(175,100)		(269,064)		(444,164)
Changes in previously estimated production costs incurred during the period		105,521		126,736		232,257
Development costs incurred during the period		21,184		198,912		220,096
Extensions, discoveries and improved recovery, net of related costs		1,260		63,327		64,587
Revisions of previous quantity estimates		(139,081)		(248,444)		(387,525)
Sales of reserves in place		(13,501)		(3,445)		(16,946)
Purchases of reserves in place		263		—		263
Accretion of discount		27,039		71,191		98,230
Net change in income taxes		—		63		63
Balance, end of year	$	114,324	$	552,403	$	666,727

As at December 31, 2015 *(thousands of Canadian dollars)*		**Canada**		**United States**		**Total**
Balance, beginning of year	$	1,917,817	$	2,195,351	$	4,113,168
Sales, net of production costs		(215,008)		(316,975)		(531,983)
Net change in prices and production costs related to future production		(1,301,100)		(2,643,661)		(3,944,761)
Changes in previously estimated production costs incurred during the period		350,453		339,085		689,538
Development costs incurred during the period		66,888		449,789		516,677
Extensions, discoveries and improved recovery, net of related costs		12,799		156,004		168,803
Revisions of previous quantity estimates		(882,249)		144,663		(737,586)
Sales of reserves in place		(12,765)		—		(12,765)
Purchases of reserves in place		2,701		—		2,701
Accretion of discount		167,972		218,267		386,239
Net change in income taxes		289,278		312,209		601,487
Balance, end of year	$	396,786	$	854,732	$	1,251,518

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2016 *(thousands of Canadian dollars)*		**Canada**		**United States**		**Total**
Proved properties	$	3,446,133	$	4,317,904	$	7,764,037
Unproved properties		118,224		190,238		308,462
Total capital costs		3,564,357		4,508,142		8,072,499
Accumulated depletion and depreciation		(1,991,842)		(1,620,026)		(3,611,868)
Net capitalized costs	$	1,572,515	$	2,888,116	$	4,460,631

As at December 31, 2015 *(thousands of Canadian dollars)*		**Canada**		**United States**		**Total**
Proved properties	$	3,436,374	$	4,147,907	$	7,584,281
Unproved properties		119,520		459,449		578,969
Total capital costs		3,555,894		4,607,356		8,163,250
Accumulated depletion and depreciation		(1,564,255)		(1,345,851)		(2,910,106)
Net capitalized costs	$	1,991,639	$	3,261,505	$	5,253,144

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2016

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

For year ended December 31, 2016 (thousands of Canadian dollars)		**Canada**		**United States**		**Total**
Property acquisition costs						
Proved properties	$	54	$	—	$	54
Unproved properties		102		—		102
Property dispositions		(9,039)		(54,237)		(63,276)
Development costs[1]		21,184		198,910		220,094
Exploration costs [2]		4,689		—		4,689
Total	$	16,990	$	144,673	$	161,663

For year ended December 31, 2015 (thousands of Canadian dollars)		**Canada**		**United States**		**Total**
Property acquisition costs						
Proved properties	$	420	$	132	$	552
Unproved properties		1,813		—		1,813
Property dispositions		(592)		(125)		(717)
Development costs[1]		66,888		449,789		516,677
Exploration costs [2]		4,362		—		4,362
Total	$	72,891	$	449,796	$	522,687

(1) Development and facilities capital expenditures.
(2) Cost of geological and geophysical capital expenditures and drilling costs for exploratory wells.

Results of Operations for Producing Activities

For year ended December 31, 2016 (thousands of Canadian dollars except per boe amounts)		**Canada**		**United States**		**Total**
Petroleum and natural gas revenues, net of royalties	$	261,912	$	340,067	$	601,979
Less:						
Operating costs, production and mineral taxes		142,242		98,463		240,705
Transportation and blending expense		37,879		—		37,879
Depreciation and depletion		214,747		293,562		508,309
Operating income		(132,956)		(51,958)		(184,914)
Income taxes		(6,886)		(1,156)		(8,042)
Results of operations [1]	$	(126,070)	$	(50,802)	$	(176,872)
Depletion rate per net boe		21.08		29.79		25.36

For year ended December 31, 2015 (thousands of Canadian dollars except per boe amounts)		**Canada**		**United States**		**Total**
Petroleum and natural gas revenues, net of royalties	$	453,781	$	426,218	$	879,999
Less:						
Operating costs, production and mineral taxes		210,945		109,242		320,187
Transportation and blending expense		80,957		—		80,957
Depreciation and depletion		284,011		377,847		661,858
Operating income		(122,132)		(60,871)		(183,003)
Income taxes		6,961		1,946		8,907
Results of operations [1]	$	(129,093)	$	(62,817)	$	(191,910)
Depletion rate per net boe		21.30		35.13		27.47

(1) Excludes corporate overhead and interest costs.