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, 2017
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)

Capitol Corporate Services, Inc.
206 E. 9th St., Ste 1300
Austin, Texas 78701
(800) 345-4647

(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:
ý Annual Information Form ý Audited Annual Financial Statements

Indicate the number of outstanding shares of the issuer's classes of capital or common stock as of the close of the period covered by the annual report: 235,450,896

Indicate by check mark whether the Registrant by filing the information contained in this Form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the “Exchange Act”). If “Yes” is marked, indicate the file number assigned to the Registrant in connection with such Rule.

Yes ¨ 82- _____ No ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Exchange Act during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports) and (2) has been subject to such filing requirements for the past 90 days.

Yes ý No ¨

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act. Emerging growth company ¨

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ¨

† The term “new or revised financial accounting standard” refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

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, 2017, 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, 2017, 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, 2017, 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, 2017, 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, 2017, 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, 2017, 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, 2017, 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, 2017, 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, 2017, 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 "Capital Resources and Liquidity - Contractual Obligations" in the Registrant's Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2017, 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 9, 2018.

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, 2017.
99.2	Audited Consolidated Financial Statements of the Registrant for the year ended December 31, 2017 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, 2017. (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 Sproule Unconventional Limited, independent engineers.
99.10	Consent of Ryder Scott Company, L.P., independent engineers.
99.11	Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited).

(1) Incorporated by reference from Form 6-K filed on March 6, 2018

Exhibit 99.1



ANNUAL INFORMATION FORM

2017

MARCH 9, 2018

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APPENDIX B	REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE
APPENDIX C	REPORT ON RESERVES DATA AND CONTINGENT RESOURCES 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., a corporation organized under the laws of the State of Delaware.

Board or **Board of Directors** means the board of directors of Baytex.

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

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, 2018.

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, 2018.

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, 2018.

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, 2018.

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, March 6, 2015 and December 15, 2017.

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, July 25, 2014 and December 15, 2017.

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 16, 2018 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, 2017*)", which is a consolidation of: (i) the report of Sproule dated January 22, 2018 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. in Canada (As of December 31, 2017)*" and (ii) the report of Ryder Scott dated February 1, 2018 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, 2017*".

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

API	the measure of the density or gravity of liquid petroleum products as compared to water
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.**
boe/d	barrels of oil equivalent per day
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
AECO	the natural gas storage facility located at Suffield, Alberta
NYMEX	the New York Mercantile Exchange
LLS	Louisiana Light Sweet
WTI	West Texas Intermediate
WCS	Western Canadian Select
$ 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 2018 capital budget range; our goal of building value through internal property development and 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 2018 based on the future net revenue disclosed in our reserves; that we market our production with attention to maximizing value and counterparty performance; the development plans for our undeveloped reserves; our future abandonment and reclamation liabilities; our funding sources for development capital expenditures; the impact of existing and proposed governmental and

environmental regulation; our dividend policy; that John A. Brussa and Rusty Goepel will not stand for election as directors at our shareholder meeting in May 2018; and our assessment of our tax filing position for the years 2011 through 2015.

In addition, there are forward-looking statements in this Annual Information Form under the headings " *General Description of Our Business*" and "*Statement of Reserves Data*" 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: oil 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 and price differentials; the availability and 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; availability and cost of gathering, processing and pipeline systems; public perception and its influence on the regulatory regime; 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; 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 oil 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; risks associated with our use of 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 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 Adjusted Funds Flow

This Annual Information Form contains references to adjusted funds flow, 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 adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. We believe that this measure provides a more complete understanding of our operating performance and our ability to generate funds for capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. However, adjusted funds flow 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 adjusted funds flow to cash flow from operating activities, see our MD&A for the year ended December 31, 2017 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. Baytex is the successor to the business of Baytex Energy Trust, which was transitioned to Baytex on December 31, 2010.

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.

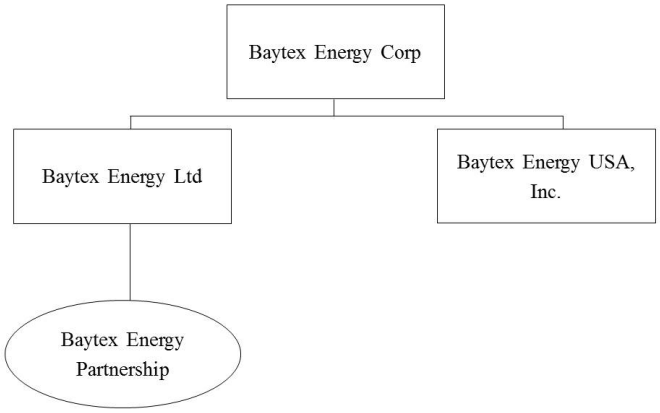
Inter-Corporate Relationships

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

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

Developments in the Past Three Years

2015

On February 19, in response to the challenging oil price environment and to maintain financial liquidity, we announced a reduced 2015 capital budget range of $500-$575 million, down from $575-$650 million, along with amendments to our Credit Facilities that relaxed our financial covenants.

On April 2, 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.

On August 20, as a further response to the continued low commodity price environment and to increase the long term sustainability of our business, we announced the suspension of our dividend. We also reduced our planned 2015 annual capital spending to approximately $500 million, which included the suspension of drilling in Canada.

On December 10, we announced a 2016 capital budget range of $325-$400 million along with additional amendments to the financial covenants in our Credit Facilities to provide increased financial flexibility.

2016

On March 3, in response to a further decline in commodity prices, we announced a reduced 2016 capital budget of $225-$265 million and the shut-in of 7,500 bbl/d of low or negative margin heavy oil production.

On March 31, 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, 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, we entered into an asset acquisition agreement to acquire heavy oil assets in the Peace River area for approximately $65 million. The lands were 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.

On December 12, we announced a 2017 capital budget range of $300-$350 million.

2017

On January 20, we closed the previously announced acquisition of heavy oil assets in the Peace River area.

On May 4, Ed LaFehr was appointed Chief Executive Officer, succeeding James Bowzer.

On December 7, we announced a 2018 capital budget range of $325-$375 million.

GENERAL DESCRIPTION OF OUR BUSINESS

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. 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.

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2017. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2017 and production information represents average working interest production for the year ended December 31, 2017.

Principal Properties

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



Lloydminster Business Unit

The Lloydminster Business Unit accounted for approximately 13% of total production in 2017. 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 200 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 purchasers. All production rates reported are for heavy crude oil, before the addition of diluents.

In 2017, production in the Lloydminster Business Unit averaged approximately 9,137 boe/d, which was comprised of 8,133 bbl/d of heavy oil, 867 bbl/d of bitumen, and 784 Mcf/d of natural gas. During 2017, Baytex drilled 65 (33.0 net)

wells in the Lloydminster Business Unit resulting in 65 (33.0 net) oil wells, for a success rate of 100% (100% net). Our net undeveloped lands in the Lloydminster Business Unit totaled approximately 185,962 acres at year-end 2017.

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 2017 was approximately 621 bbl/d of heavy oil and 260 Mcf/d of natural gas (665 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 metre horizontal lateral, was completed with steam circulation into the injector and producer commencing on January 24, 2014. The producing well was converted to production in May 2014 and produced until April 2015, when an electrical fire at the facility resulted in damage to equipment and resulted in the project being suspended. 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 2017, Baytex had 78,781 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. In 2017, 13 (13.0 net) horizontal wells (including three multi-laterals) were drilled. Average production in 2017 was approximately 2,603 bbl/d of heavy oil (2,603 boe/d). At year-end 2017, Baytex had 9,627 net undeveloped acres in this area.

Celtic, Saskatchewan: This property was acquired by Baytex in 2005. Celtic 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 2017 was approximately 922 bbl/d of heavy oil. At year-end 2017, Baytex had 4,558 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 in 2017 from the cold primary and thermal assets averaged approximately 792 bbl/d of heavy oil, 867 bbl/d of bitumen, 2 bbl/d of light oil and NGL and 11 Mcf/d of natural gas (1,663 boe/d). At year-end 2017, Baytex had 33,963 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. In 2017, Baytex drilled four (4.0 net) horizontal oil wells with a 100% success rate. Average production during 2017 was approximately 1,566 bbl/d of heavy oil and 191 Mcf/d of natural gas (1,597 boe/d). At year-end 2017, Baytex had 4,646 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 25% of total Baytex production in 2017. In January 2017, Baytex completed the acquisition of 380 net sections of oil sands leases, including 213,760 net acres of undeveloped land, along with associated production of approximately 3,000 boe/d. Baytex held approximately 473,855 net undeveloped acres in the Peace River Business Unit at year-end 2017. In 2017, Baytex drilled nine (9.0 net) horizontal multi-lateral wells and eight (8.0 net) stratigraphic test wells in the Peace River Business Unit.

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.

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

Harmon Valley, Alberta: Baytex holds a total of 112 net sections of oil sands leases in the Harmon Valley area. During 2017, Baytex drilled six (6.0 net) wells in Harmon Valley resulting in three (3.0 net) oil wells, and three (3.0 net) stratigraphic/service wells, for a success rate of 100% (100% net). Average production during 2017 from the Harmon Valley area was approximately 12,588 bbl/d of heavy oil, and 3,754 Mcf/d of natural gas (13,214 boe/d). At year-end 2017, Baytex had 37,600 net undeveloped acres of oil sands leases in this area.

In 2017, Baytex commenced construction of a natural gas processing plant in the Harmon Valley area which will process natural gas produced in conjunction with the heavy oil. This plant is anticipated to commence operations in August 2018 and will result in the conservation of approximately 9.0 mmcf/d of natural gas.

Seal, Alberta: At present, Baytex holds a total of 338 net sections of oil sands leases in the Seal area. During 2017, Baytex drilled five (5.0 net) wells in Seal resulting in three (3.0 net) oil wells and two (2.0 net) stratigraphic/service wells, for a success rate of 100% (100% net). Average production during 2017 from the Seal area was approximately 2,978 bbl/d of heavy oil, and 2,415 Mcf/d of natural gas (3,416 boe/d). At year-end 2017, Baytex had 190,760 net undeveloped acres of oil sands leases in this area.

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 10% of total Baytex production in 2017. During 2017, production from this business unit averaged 6,874 boe/d, which was comprised of 2,165 bbl/d of light oil and NGL and 28,253 Mcf/d of natural gas. At year-end 2017, we had 134,250 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 facilities for processing. Baytex owns a working interest in one of the midstream-operated gas processing facilities. Production from this area during 2017 averaged 1,072 bbl/d of light oil and NGL and 20,792 Mcf/d of natural gas (4,538 boe/d). Baytex drilled four (4.0 net) wells in this area in 2017, resulting in four (4.0 net) natural gas wells. At year-end 2017, Baytex had 28,899 net undeveloped acres in this area.

United States Business Unit

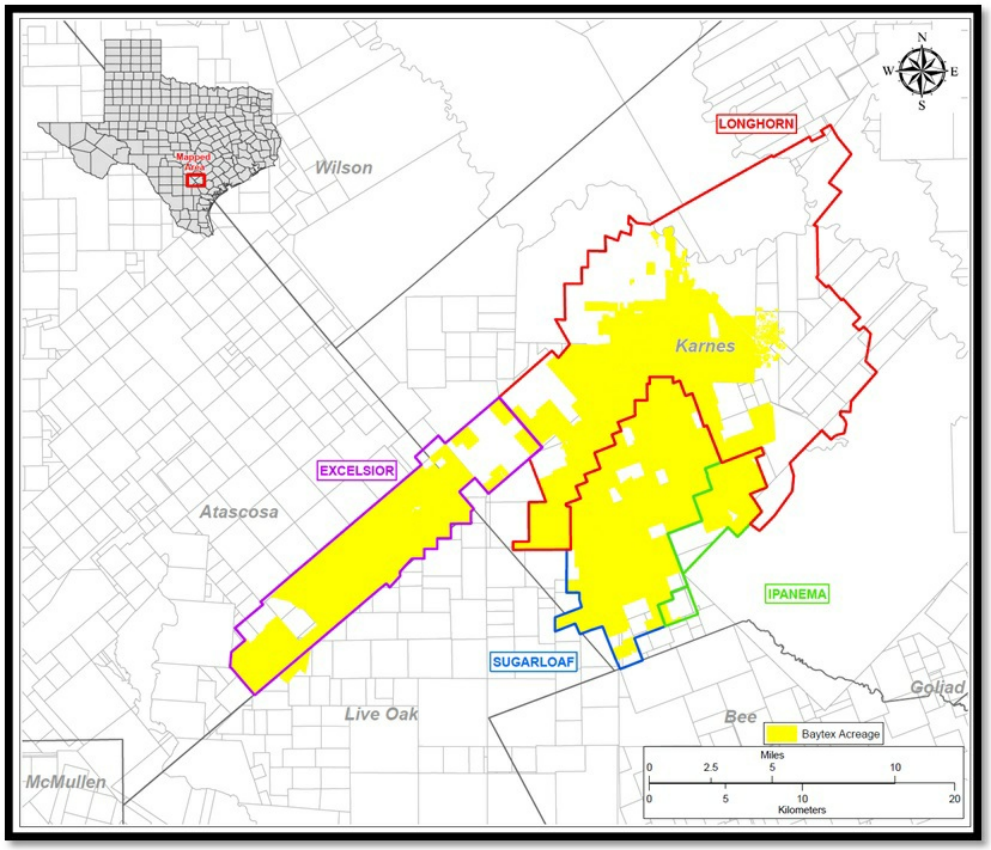
On June 11, 2014, through the acquisition of Aurora Oil & Gas Limited, Baytex acquired a position in the Sugarkane area which is located in the core of the liquids-rich Eagle Ford shale in South Texas. Our assets include non-operated working interests in approximately 78,112 (19,842 net) acres, comprised of four areas of mutual interest (Sugarloaf, Longhorn, Ipanema and Excelsior), together with 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 outside the Sugarkane area (185 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, 2017:

	Gross Acreage	Net Acreage
Sugarloaf AMI	24,145	6,768
Longhorn AMI	30,111	9,592
Ipanema AMI	4,771	1,737
Excelsior AMI	19,085	1,745
Sugarkane area total	78,112	19,842
Other Texas	193	185
Grand Total	78,305	20,027

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 2017, production from the United States Business Unit averaged approximately 28,313 bbl/d of light oil and NGL and 50,189 Mcf/d of shale gas (36,678 boe/d). During this period, Baytex participated in the drilling of

140 (32.8 net) wells in the Sugarkane area, resulting in 90 (17.9 net) oil wells and 50 (14.9 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, 2017.

	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	621	—	—	—	—	—	260	665
Soda Lake	2,603	—	—	—	—	—	—	2,603
Celtic	922	—	—	—	—	—	—	922
Kerrobert / Hoosier	792	867	2	—	—	—	11	1,663
Tangleflags	1,566	—	—	—	—	—	191	1,597
Remaining properties	1,629	—	5	—	—	—	322	1,687
Total	8,133	867	7	—	—	—	784	9,137
Peace River Business Unit								
Harmon Valley	12,588	—	—	—	—	—	3,754	13,214
Seal	2,978	—	—	—	35	—	2,415	3,416
Remaining properties	760	—	—	—	—	—	981	923
Total	16,326	—	—	—	35	—	7,150	17,553
Conventional Business Unit								
Pembina	—	—	149	—	923	—	20,792	4,538
Remaining properties	—	—	1,007	—	86	—	7,461	2,336
Total	—	—	1,156	—	1,009	—	28,253	6,874
United States Business Unit	—	—	—	20,151	8,162	50,189	—	36,678
Grand Total	24,459	867	1,163	20,151	9,206	50,189	36,187	70,242

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2017:

($000s)	Canada	United States	Total
Property acquisition costs			
Proved properties	71,643	—	71,643
Unproved properties	—	—	—
Property disposition	(11,786)	—	(11,786)
Total Property acquisition costs, net	59,857	—	59,857
Development Costs[1]	106,156	212,992	319,148
Exploration Costs[2]	7,118	—	7,118
Total	173,131	212,992	386,123

Notes:
(1) Development and facilities expenditures.
(2) Cost of geological and geophysical capital expenditures and drilling costs for 2017 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, 2017.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	1,259	941.2	1,080	677.3	370	289.2	452	350.9
Saskatchewan	615	596.6	1,242	1,181.7	19	15.7	123	113.3
Texas	622	141.9	37	5.9	365	99.8	48	15.1
Total	2,496	1,679.7	2,359	1,864.9	754	404.7	623	479.3

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2017.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	748,920	688,166
Saskatchewan	111,360	105,901
Total Canada	860,280	794,067
United States	117	102
Grand Total	860,397	794,169

Undeveloped land holdings are lands that have not been assigned reserves as at 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.

We estimate the value of our net undeveloped land holdings at December 31, 2017 to be approximately $75.9 million, as compared to $67.1 million as at December 31, 2016. 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 10,989 net acres of our undeveloped land holdings (comprised of 98 net acres in the United States and 10,891 net acres in Canada) will expire on or before December 31, 2018. There are no reserves associated with the land holdings expected to expire by December 31, 2018.

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, 2017.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Oil	—	—	164	59.7	164 15.78	59.7
Natural Gas	—	—	54	18.9	54	18.9
Stratigraphic	8	8.0	—	—	8	8.0
Service	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total	8	8.0	218	78.6	226	86.6

Tax Horizon

Baytex does not expect to pay any material cash income taxes prior to 2022. 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, adjusted funds flow, 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, 2017 and the information under the headings "*Income Taxes*" and "*Tax Pools*" in our MD&A for the year ended December 31, 2017.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ending December 31, 2018, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Statement of Reserves Data - Disclosure of Reserves Data*".

	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	21,081	384	682	—	918	—	31,884	28,379
Total Proved plus Probable	23,042	636	714	—	1,070	—	36,434	31,534
UNITED STATES								
Total Proved	—	—	—	10,351	15,838	30,961	16,394	34,082
Total Proved plus Probable	—	—	—	10,351	16,272	31,727	16,394	34,644
TOTAL								
Total Proved	21,081	384	682	10,351	16,756	30,961	48,278	62,461
Total Proved plus Probable	23,042	636	714	10,351	17,342	31,727	52,827	66,178

The two properties that account for 20% or more of the estimated 2018 production volumes are the Eagle Ford and Peace River (cold primary production). Estimated 2018 production volumes for Eagle Ford are 34,082 boe/d on a total proved basis and 34,644 boe/d on a total proved plus probable basis. Estimated 2018 production volumes for Peace River (cold primary production) are 15,529 boe/d on a total proved basis and 16,369 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, 2017	**Sep. 30, 2017**	**Jun. 30, 2017**	**Mar. 31, 2017**	**Dec. 31, 2017**
Average Sales Volume [1]					
Heavy Oil (bbl/d)	24,190	25,336	24,767	23,543	24,459
Bitumen (bbl/d)	755	825	810	1,082	867
Light Oil (bbl/d)	882	1,245	1,258	1,252	1,163
NGL (bbl/d)	9,872	8,940	9,693	8,306	9,206
Tight Oil (bbl/d)	20,347	18,796	21,112	20,365	20,151
Shale Gas (Mcf/d)	48,779	48,842	52,120	51,055	50,189
Natural Gas (Mcf/d)	32,284	36,164	38,908	37,447	36,186
Total (boe/d)	69,556	69,310	72,812	69,298	70,242
Average Net Production Prices Received					
Heavy Oil ($/bbl)	41.96	38.12	37.57	35.90	38.41
Bitumen ($/bbl)	44.31	40.19	39.10	37.33	39.96
Light Oil ($/bbl)	62.47	52.57	54.07	58.05	56.24
NGL ($/bbl)	29.14	25.18	22.70	26.35	25.86
Tight Oil ($/bbl)	73.08	58.59	61.07	63.58	64.17
Shale Gas ($/Mcf)	3.67	3.76	4.34	4.17	3.99
Natural Gas ($/Mcf)	1.72	1.72	2.66	2.64	2.21
Total ($/boe)	44.75	38.04	39.41	40.16	40.58
Royalties Paid					
Heavy Oil ($/bbl)	7.25	5.71	5.36	5.12	5.87
Bitumen ($/bbl)	4.08	3.77	2.68	2.45	3.18
Light Oil and NGL ($/bbl) [2]	7.56	6.52	6.68	6.82	6.90
Tight Oil ($/bbl)	21.90	17.59	18.20	18.97	19.19
Shale Gas ($/Mcf)	1.01	1.03	1.17	1.15	1.09
Natural Gas ($/Mcf)	0.04	0.13	0.16	0.05	0.10
Total ($/boe)	10.86	8.65	9.06	9.17	9.43
Operating Expenses [3]					
Heavy Oil ($/bbl)	17.03	14.29	14.66	14.34	15.08
Bitumen ($/bbl)	33.40	20.74	31.77	20.47	26.00
Light Oil and NGL ($/bbl) [2]	7.29	7.61	8.43	8.45	7.94
Tight Oil ($/bbl) [4]	6.04	6.53	7.11	6.38	6.52
Shale Gas ($/Mcf) [4]	1.01	1.09	1.19	1.06	1.09
Natural Gas ($/Mcf)	2.21	1.86	2.22	2.34	2.16
Total ($/boe)	10.91	10.10	10.70	10.28	10.50

	Three Months Ended				Year Ended
	Dec. 31, 2017	Sep. 30, 2017	Jun. 30, 2017	Mar. 31, 2017	Dec. 31, 2017
Transportation Expenses					
Heavy Oil ($/bbl)	2.90	3.39	3.32	3.10	3.18
Bitumen ($/bbl)	1.32	1.62	1.73	1.49	1.54
Light Oil and NGL ($/bbl) (2)	0.32	0.32	0.29	0.35	0.29
Tight Oil ($/bbl) (4)	—	—	—	—	—
Shale Gas ($/Mcf) (4)	—	—	—	—	—
Natural Gas ($/Mcf)	0.30	0.30	0.31	0.30	0.30
Total ($/boe)	1.20	1.46	1.35	1.29	1.33
Netback Received (5)					
Heavy Oil ($/bbl)	15.14	15.05	14.68	13.47	14.60
Bitumen ($/bbl)	5.50	14.06	2.92	12.93	9.24
Light Oil and NGL ($/bbl) (2)	29.56	25.06	27.42	29.23	27.74
Tight Oil ($/bbl)	45.15	34.48	35.76	38.23	38.46
Shale Gas ($/Mcf)	1.66	1.64	1.98	1.95	1.81
Natural Gas ($/Mcf)	(0.83)	(0.58)	(0.03)	(0.06)	(0.35)
Total ($/boe)	21.78	17.83	18.30	19.42	19.32
Financial Derivatives gain ($/boe)	0.30	0.44	0.40	0.04	0.30
Netback Received after hedging ($/boe)	22.08	18.27	18.70	19.46	19.62

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, 2017, the prompt price settlements of WTI fluctuated from a low of US$42.53/bbl on June 21 to a high of US$60.42/bbl on December 29, with an average price of US$50.95/bbl. WTI remained depressed over the first half of the year as inventory levels in the United States remained high despite the OPEC supply accord. In the second half of the year, OPEC compliance with its supply accord remained strong and inventories in the United States began to decrease, causing WTI prices to increase through to year-end.

The discount for Canadian heavy oil, as measured by the WCS price differential to WTI, averaged US$11.98/bbl in 2017, as compared to US$13.84 in 2016.

For 2017, Baytex's heavy oil sales prices averaged $38.46/bbl, while light oil and condensate prices averaged $63.74/bbl. In contrast, for 2016 Baytex averaged $26.46/bbl for heavy oil sales and $ 50.32/bbl for light oil and condensate sales. Baytex's NGL price in 2017 was $ 25.86/bbl, as compared with $17.16/bbl in 2016. In 2017, Baytex's

US light oil and condensate price realizations averaged $ 64.17/bbl, as compared to $ 50.60/bbl in 2016, as the average annual price for the WTI benchmark increased by 18% from US$43.33/bbl in 2016 to US$ 50.95/bbl in 2017.

Natural Gas

For the year ended December 31, 2017, the average AECO natural gas price was $ 2.43/Mcf, as compared to $2.09/Mcf in the same period of 2016 and the average NYMEX natural gas price was US$3.11/MMbtu in 2017 as compared to US $2.46/MMbtu in 2016. The increase in natural gas prices in North America stemmed from higher demand in the United States, improved LNG exports and increased exports to Mexico. For 2017, Baytex's average realized natural gas sales price was $3.24/Mcf, as compared to $ 2.69/Mcf in 2016.

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2017, see Note 18 to our audited consolidated financial statements for the year ended December 31, 2017.

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. Our Health, Safety and Environment policy is available on our website at www.baytexenergy.com.

We published our Corporate Responsibility Report in September 2017, detailing our efforts and performance in environmental management, health and safety, leadership culture, community investment, stakeholder engagement and corporate governance. This report can also be viewed on our website at www.baytexenergy.com.

Employees

As at December 31, 2017, we had 136 employees in our Calgary head office, 3 employees in our Houston office and 89 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 16, 2018, with an effective date of December 31, 2017. The preparation date of the statement is January 22, 2018, in the case of Sproule, and February 1, 2018, 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, 2017 forecast price and cost assumptions.

Disclosure of Reserves Data

The tables below are a combined summary as at December 31, 2017 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 the 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 Reserves 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, 2017
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	1,482	1,441	26,276	20,748	94	92
Developed Non-Producing	1	1	1,750	1,498	7,744	7,072
Undeveloped	125	122	18,680	16,608	5,428	4,546
TOTAL PROVED	1,608	1,564	46,706	38,854	13,266	11,709
PROBABLE	1,225	1,090	39,757	33,563	55,726	43,833
TOTAL PROVED PLUS PROBABLE	2,833	2,654	86,463	72,417	68,992	55,542

CANADA

	CONVENTIONAL NATURAL GAS [1]		NATURAL GAS LIQUIDS [2]		TOTAL RESERVES	
RESERVES CATEGORY	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbl)**	**Net (Mbbl)**	**Gross (Mboe)**	**Net (Mboe)**
PROVED:						
Developed Producing	43,929	37,680	1,075	761	36,249	29,322
Developed Non-Producing	27,034	25,309	21	12	14,021	12,801
Undeveloped	46,856	41,080	1,522	1,228	33,564	29,351
TOTAL PROVED	117,819	104,069	2,618	2,002	83,834	71,474
PROBABLE	89,963	77,782	3,132	2,428	114,834	93,878
TOTAL PROVED PLUS PROBABLE	207,782	181,853	5,750	4,430	198,667	165,352

UNITED STATES

RESERVES CATEGORY	TIGHT OIL Gross (Mbbl)	TIGHT OIL Net (Mbbl)	SHALE GAS Gross (MMcf)	SHALE GAS Net (MMcf)	CONVENTIONAL NATURAL GAS [1] Gross (MMcf)	CONVENTIONAL NATURAL GAS [1] Net (MMcf)
PROVED:						
Developed Producing	20,191	14,809	61,139	45,273	34,115	25,076
Developed Non-Producing	32	23	209	152	91	65
Undeveloped	30,074	22,022	111,506	82,186	29,812	21,794
TOTAL PROVED	50,296	36,854	172,855	127,611	64,018	46,935
PROBABLE	11,390	8,361	75,686	55,607	10,761	7,900
TOTAL PROVED PLUS PROBABLE	61,686	45,215	248,541	183,218	74,778	54,835
POSSIBLE [3]	19,992	14,679	89,370	65,736	19,577	14,372
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [3]	81,679	59,894	337,910	248,954	94,356	69,207

UNITED STATES

RESERVES CATEGORY	NATURAL GAS LIQUIDS [2] Gross (Mbbl)	NATURAL GAS LIQUIDS [2] Net (Mbbl)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:				
Developed Producing	28,052	20,742	64,119	47,276
Developed Non-Producing	111	81	193	140
Undeveloped	53,784	39,590	107,410	78,942
TOTAL PROVED	81,947	60,413	171,722	126,358
PROBABLE	35,830	26,333	61,628	45,278
TOTAL PROVED PLUS PROBABLE	117,777	86,745	233,349	171,635
POSSIBLE [3]	41,964	30,862	80,115	58,892
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [3]	159,741	117,607	313,464	230,528

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	20,191	14,809	1,482	1,441	26,276	20,748
Developed Non-Producing	32	23	1	1	1,750	1,498
Undeveloped	30,074	22,022	125	122	18,680	16,608
TOTAL PROVED	50,296	36,854	1,608	1,564	46,706	38,854
PROBABLE	11,390	8,361	1,225	1,090	39,757	33,563
TOTAL PROVED PLUS PROBABLE	61,686	45,215	2,833	2,654	86,463	72,417
POSSIBLE (3)(4)	19,992	14,679	—	—	—	—
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)(4)	81,679	59,894	2,833	2,654	86,463	72,417

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	94	92	61,139	45,273	78,045	62,756
Developed Non-Producing	7,744	7,072	209	152	27,125	25,374
Undeveloped	5,428	4,546	111,506	82,186	76,668	62,874
TOTAL PROVED	13,266	11,709	172,855	127,611	181,837	151,004
PROBABLE	55,726	43,833	75,686	55,607	100,723	85,683
TOTAL PROVED PLUS PROBABLE	68,992	55,542	248,541	183,218	282,561	236,687
POSSIBLE (3)(4)	—	—	89,370	65,736	19,577	14,372
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)(4)	68,992	55,542	337,910	248,954	302,138	251,059

TOTAL

RESERVES CATEGORY	NATURAL GAS LIQUIDS (2)		TOTAL RESERVES	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mboe)	Net (Mboe)
PROVED:				
Developed Producing	29,128	21,503	100,368	76,598
Developed Non-Producing	131	93	14,214	12,941
Undeveloped	55,306	40,818	140,974	108,293
TOTAL PROVED	84,564	62,414	255,556	197,831
PROBABLE	38,962	28,760	176,461	139,155
TOTAL PROVED PLUS PROBABLE	123,526	91,175	432,017	336,987
POSSIBLE (3)(4)	41,964	30,862	80,115	58,892
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE (3)(4)	165,491	122,037	512,131	395,879

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, 2017
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	394,678	392,339	359,063	327,713	300,965	12.25
Developed Non-Producing	322,386	195,869	135,648	98,310	73,393	10.60
Undeveloped	475,480	362,040	278,773	216,443	168,923	9.50
TOTAL PROVED	1,192,544	950,248	773,484	642,465	543,281	10.82
PROBABLE	2,428,609	1,326,481	806,284	526,528	360,482	8.59
TOTAL PROVED PLUS PROBABLE	3,621,153	2,276,730	1,579,768	1,168,994	903,763	9.55

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	1,771,167	1,311,579	1,045,543	875,040	757,316	22.12
Developed Non-Producing	4,334	3,227	2,537	2,080	1,763	18.18
Undeveloped	2,492,733	1,523,326	1,009,941	705,898	510,856	12.79
TOTAL PROVED	4,268,233	2,838,131	2,058,020	1,583,018	1,269,934	16.29
PROBABLE	1,679,658	812,362	452,804	276,144	178,484	10.00
TOTAL PROVED PLUS PROBABLE	5,947,892	3,650,494	2,510,824	1,859,162	1,448,419	14.63
POSSIBLE [(1)]	2,750,546	1,581,035	1,046,186	752,174	570,766	17.76
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [(1)]	8,698,438	5,231,529	3,557,009	2,611,337	2,019,185	15.43

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	2,165,845	1,703,918	1,404,606	1,202,752	1,058,281	18.34
Developed Non-Producing	326,719	199,096	138,185	100,390	75,156	10.68
Undeveloped	2,968,213	1,885,366	1,288,713	922,341	679,779	11.90
TOTAL PROVED	5,460,777	3,788,380	2,831,504	2,225,483	1,813,216	14.31
PROBABLE	4,108,268	2,138,844	1,259,087	802,673	538,966	9.05
TOTAL PROVED PLUS PROBABLE	9,569,045	5,927,224	4,090,592	3,028,156	2,352,182	12.14
POSSIBLE [(1)(2)]	2,750,546	1,581,035	1,046,186	752,174	570,766	17.76
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [(1)(2)]	12,319,591	7,508,259	5,136,777	3,780,330	2,922,948	12.98

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, 2017
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	394,678	392,339	359,063	327,713	300,965
Developed Non-Producing	322,386	195,869	135,648	98,310	73,393
Undeveloped	408,115	314,118	243,814	190,381	149,123
TOTAL PROVED	1,125,179	902,327	738,525	616,403	523,481
PROBABLE	1,790,863	955,479	563,472	354,702	232,366
TOTAL PROVED PLUS PROBABLE	2,916,042	1,857,806	1,301,997	971,106	755,847

UNITED STATES	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,759,287	1,304,937	1,041,251	871,982	754,990
Developed Non-Producing	4,147	3,139	2,491	2,053	1,744
Undeveloped	1,956,555	1,225,103	829,646	590,113	433,033
TOTAL PROVED	3,719,988	2,533,179	1,873,388	1,464,147	1,189,768
PROBABLE	1,314,991	634,665	352,618	214,209	137,812
TOTAL PROVED PLUS PROBABLE	5,034,980	3,167,844	2,226,006	1,678,356	1,327,579
POSSIBLE [2]	2,156,503	1,246,730	831,891	604,230	463,717
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [2]	7,191,483	4,414,574	3,057,897	2,282,586	1,791,297

TOTAL	**AFTER INCOME TAXES DISCOUNTED AT (%/year)[1]**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	2,153,965	1,697,276	1,400,314	1,199,694	1,055,955
Developed Non-Producing	326,532	199,008	138,139	100,363	75,137
Undeveloped	2,364,670	1,539,221	1,073,460	780,493	582,156
TOTAL PROVED	4,845,167	3,435,505	2,611,913	2,080,550	1,713,249
PROBABLE	3,105,854	1,590,144	916,090	568,912	370,178
TOTAL PROVED PLUS PROBABLE	7,951,022	5,025,650	3,528,003	2,649,462	2,083,426
POSSIBLE [2][3]	2,156,503	1,246,730	831,891	604,230	463,717
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE [2][3]	10,107,525	6,272,380	4,359,894	3,253,692	2,547,143

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, 2017
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	3,680,729	553,289	1,410,224	406,921	117,751	1,192,544	67,365	1,125,179
United States	11,375,765	3,512,482	2,268,410	1,270,875	55,765	4,268,233	548,245	3,719,988
Total	15,056,494	4,065,771	3,678,634	1,677,796	173,516	5,460,777	615,610	4,845,167
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	10,901,025	1,943,825	3,805,241	1,368,291	162,514	3,621,153	705,111	2,916,042
United States	16,161,524	4,988,360	3,348,480	1,802,465	74,326	5,947,892	912,912	5,034,980
Total	27,062,548	6,932,186	7,153,721	3,170,757	236,840	9,569,045	1,618,023	7,951,022
TOTAL PROVED PLUS PROBABLE PLUS POSSIBLE RESERVES (2)(3)								
Canada	10,901,025	1,943,825	3,805,241	1,368,291	162,514	3,621,153	705,111	2,916,042
United States	22,052,848	6,807,605	4,252,252	2,207,869	86,684	8,698,438	1,506,955	7,191,483
Total	32,953,873	8,751,431	8,057,493	3,576,160	249,198	12,319,591	2,212,066	10,107,525

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, 2017
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)	34,709	18.63
	Heavy Crude Oil (including solution gas and associated byproducts)	484,681	10.50
	Bitumen (including solution gas and associated byproducts)	195,250	16.68
	Tight Oil (including solution gas and associated byproducts)	1,044,695	19.99
	Natural Gas (associated and non-associated) (including associated byproducts)	58,845	5.02
	Shale Gas (including associated byproducts)	1,013,325	13.68
	Total	2,831,504	
Proved plus Probable	Light and Medium Crude Oil (including solution gas and associated byproducts)	46,022	12.91
	Heavy Crude Oil (including solution gas and associated byproducts)	884,775	10.96
	Bitumen (including solution gas and associated byproducts)	511,714	9.21
	Tight Oil (including solution gas and associated byproducts)	1,171,164	18.91
	Natural Gas (associated and non-associated) (including associated byproducts)	137,257	5.37
	Shale Gas (including associated byproducts)	1,339,659	12.21
	Total	4,090,592	
Proved plus Probable plus Possible [2][3]	Light and Medium Crude Oil (including solution gas and associated byproducts)	46,022	12.91
	Heavy Crude Oil (including solution gas and associated byproducts)	884,775	10.96
	Bitumen (including solution gas and associated byproducts)	511,714	9.21
	Tight Oil (including solution gas and associated byproducts)	1,620,787	19.99
	Natural Gas (associated and non-associated) (including associated byproducts)	137,257	5.37
	Shale Gas (including associated byproducts)	1,936,222	12.96
	Total	5,136,777	

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, 2017[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								
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	38.89	2.55	2.18	1.2	(3.4)	0.755
2017	50.95	61.84	48.78	3.02	2.20	2.2	(3.4)	0.771
Forecast[9]								
2018	55.00	65.44	51.05	3.25	2.85	—	—	0.790
2019	65.00	74.51	59.61	3.50	3.11	2.0	2.0	0.820
2020	70.00	78.24	64.94	4.00	3.65	2.0	2.0	0.850
2021	73.00	82.45	68.43	4.08	3.80	2.0	2.0	0.850
2022	74.46	84.10	69.80	4.16	3.95	2.0	2.0	0.850
2023	75.95	85.78	71.20	4.24	4.05	2.0	2.0	0.850
2024	77.47	87.49	72.62	4.33	4.15	2.0	2.0	0.850
2025	79.02	89.24	74.07	4.42	4.25	2.0	2.0	0.850
2026	80.60	91.03	75.55	4.50	4.36	2.0	2.0	0.850
2027	82.21	92.85	77.06	4.59	4.46	2.0	2.0	0.850
2028	83.85	94.71	78.61	4.69	4.57	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 2028 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, 2017, excluding hedging activities, were $ 38.41/bbl for heavy oil, $39.96/bbl for bitumen, $56.24/bbl for light oil, $64.17/bbl for tight oil, $25.86/bbl for NGL, $3.99/Mcf for shale gas and $2.21/Mcf for natural gas.

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

CANADA	HEAVY OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300
Extensions	638	500	1,138	—	—	—
Infill Drilling	369	364	732	—	—	—
Improved Recovery	—	1,997	1,997	—	—	—
Technical Revisions	1,121	(2,861)	(1,740)	197	(142)	55
Discoveries	—	—	—	—	—	—
Acquisitions [1]	7,941	11,334	19,275	—	—	—
Dispositions	(1,221)	(974)	(2,195)	—	—	—
Economic Factors	(89)	73	(16)	(80)	33	(47)
Production	(8,927)	—	(8,927)	(317)	—	(317)
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992

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, 2016	2,293	1,794	4,087	115,933	89,206	205,139
Extensions	—	—	—	2,067	5,042	7,109
Infill Drilling	—	—	—	29	9	38
Improved Recovery	—	—	—	—	—	—
Technical Revisions	422	31	453	9,367	(7,104)	2,264
Discoveries	—	—	—	—	—	—
Acquisitions [1]	—	—	—	4,241	3,008	7,249
Dispositions	(720)	(559)	(1,279)	(2)	(2)	(4)
Economic Factors	38	(41)	(3)	(608)	(196)	(804)
Production	(425)	—	(425)	(13,208)	—	(13,208)
December 31, 2017	1,608	1,225	2,833	117,819	89,963	207,782

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, 2016	2,590	3,198	5,788	84,544	105,019	189,564
Extensions	90	224	314	1,073	1,564	2,637
Infill Drilling	—	—	—	373	365	739
Improved Recovery	—	—	—	—	1,997	1,997
Technical Revisions	212	(363)	(151)	3,514	(4,519)	(1,005)
Discoveries	—	—	—	—	—	—
Acquisitions [1]	115	81	196	8,763	11,916	20,679
Dispositions	(0)	—	(0)	(1,942)	(1,534)	(3,475)
Economic Factors	(8)	(8)	(16)	(241)	25	(216)
Production	(381)	—	(381)	(12,251)	—	(12,251)
December 31, 2017	2,618	3,132	5,750	83,834	114,834	198,667

UNITED STATES	TIGHT OIL			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2016	49,714	8,399	58,113	173,828	59,075	232,903
Extensions	—	—	—	—	—	—
Infill Drilling	1,307	2,252	3,559	2,096	6,464	8,560
Improved Recovery	—	—	—	—	—	—
Technical Revisions [4]	3,821	736	4,557	7,590	10,190	17,781
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	8	3	11	(133)	(43)	(177)
Production	(4,553)	—	(4,553)	(10,526)	—	(10,526)
December 31, 2017	50,296	11,390	61,686	172,855	75,686	248,541

UNITED STATES	CONVENTIONAL NATURAL GAS [2]			NATURAL GAS LIQUIDS [3]		
	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2016	56,083	8,906	64,988	80,102	28,627	108,728
Extensions	—	—	—	—	—	—
Infill Drilling	3,392	836	4,228	1,393	1,095	2,488
Improved Recovery	—	—	—	—	—	—
Technical Revisions [4]	12,336	1,018	13,353	6,275	6,121	12,396
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors	—	2	2	(41)	(13)	(55)
Production	(7,793)	—	(7,793)	(5,781)	—	(5,781)
December 31, 2017	64,018	10,761	74,778	81,947	35,830	117,777

UNITED STATES	OIL EQUIVALENT		
	Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2016	168,134	48,356	216,490
Extensions	—	—	—
Infill Drilling	3,614	4,564	8,178
Improved Recovery	—	—	—
Technical Revisions [4]	13,417	8,725	22,142
Discoveries	—	—	—
Acquisitions	—	—	—
Dispositions	—	—	—
Economic Factors	(55)	(17)	(73)
Production	(13,388)	—	(13,388)
December 31, 2017	171,722	61,628	233,350

TOTAL	HEAVY OIL			BITUMEN		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2016	46,875	29,325	76,199	13,465	55,835	69,300
Extensions	638	500	1,138	—	—	—
Infill Drilling	369	364	732	—	—	—
Improved Recovery	—	1,997	1,997	—	—	—
Technical Revisions	1,121	(2,861)	(1,740)	197	(142)	55
Discoveries	—	—	—	—	—	—
Acquisitions [1]	7,941	11,334	19,275	—	—	—
Dispositions	(1,221)	(974)	(2,195)	—	—	—
Economic Factors	(89)	73	(16)	(80)	33	(47)
Production	(8,927)	—	(8,927)	(317)	—	(317)
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992

TOTAL	LIGHT AND MEDIUM OIL			TIGHT OIL		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)
December 31, 2016	2,293	1,794	4,087	49,714	8,399	58,113
Extensions	—	—	—	—	—	—
Infill Drilling	—	—	—	1,307	2,252	3,559
Improved Recovery	—	—	—	—	—	—
Technical Revisions [4]	422	31	453	3,821	736	4,557
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	(720)	(559)	(1,279)	—	—	—
Economic Factors	38	(41)	(3)	8	3	11
Production	(425)	—	(425)	(4,553)	—	(4,553)
December 31, 2017	1,608	1,225	2,833	50,296	11,390	61,686

TOTAL	NATURAL GAS LIQUIDS [3]			SHALE GAS		
	Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2016	82,692	31,825	114,516	173,828	59,075	232,903
Extensions	90	224	314	—	—	—
Infill Drilling	1,393	1,095	2,488	2,096	6,464	8,560
Improved Recovery	—	—	—	—	—	—
Technical Revisions [4]	6,487	5,758	12,245	7,590	10,190	17,781
Discoveries	—	—	—	—	—	—
Acquisitions [1]	115	81	196	—	—	—
Dispositions	(0)	—	(0)	—	—	—
Economic Factors	(50)	(21)	(71)	(133)	(43)	(177)
Production	(6,162)	—	(6,162)	(10,526)	—	(10,526)
December 31, 2017	84,564	38,962	123,526	172,855	75,686	248,541

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, 2016	172,016	98,112	270,127	252,679	153,375	406,053
Extensions	2,067	5,042	7,109	1,073	1,564	2,637
Infill Drilling	3,421	845	4,266	3,987	4,929	8,916
Improved Recovery	—	—	—	—	1,997	1,997
Technical Revisions [4]	21,703	(6,086)	15,617	16,931	4,206	21,137
Discoveries	—	—	—	—	—	—
Acquisitions [1]	4,241	3,008	7,249	8,763	11,916	20,679
Dispositions	(2)	(2)	(4)	(1,942)	(1,534)	(3,475)
Economic Factors	(608)	(195)	(803)	(296)	8	(289)
Production	(21,001)	—	(21,001)	(25,639)	—	(25,639)
December 31, 2017	181,837	100,724	282,560	255,556	176,461	432,017

Note:
(1) Heavy oil and conventional natural gas acquisitions are principally attributable to reserves associated with the Peace River assets acquired on January 20, 2017.
(2) Conventional natural gas includes associated, non-associated and solution gas.
(3) Natural gas liquids includes condensate.
(4) Positive technical revisions for tight oil, natural gas liquids and shale gas are largely the result of enhanced type well profiles on our Eagle Ford acreage.

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, timing of infrastructure construction 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 0.6 Mbbls of proved developed non-producing reserves and 42.4 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
2015	—	99	3,122	28,812	1,506	27,362	—	5,429
2016	—	308	4,561	30,472	1,215	18,343	—	5,428
2017	—	125	1,096	30,074	4,529	18,680	—	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
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
2017	6,690	76,668	863	111,506	918	55,306

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
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
2017	—	806	2,234	8,511	12,764	29,878	—	47,137

	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
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
2017	7,996	86,334	6,413	68,455	1,347	35,305

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, inflated at 2% per year is estimated to be $519.8 million undiscounted ($58.8 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, 2017
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
2018	98,043	126,225	136,837	149,937	234,879	276,163
2019	155,071	188,546	311,259	315,979	466,330	504,524
2020	133,323	357,593	302,301	316,986	435,624	674,579
2021	6,348	263,674	232,243	297,916	238,591	561,590
2022	12,401	122,321	146,451	249,786	158,852	372,107
Remaining	1,734	309,933	141,785	471,862	143,519	781,794
Total (undiscounted)	406,921	1,368,291	1,270,875	1,802,465	1,677,796	3,170,757

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

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 in the Eagle Ford property effective December 31, 2017. 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, 2017 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, 2017. A summary of these contingent resources estimates is provided in Appendix A.

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

Volatility of oil and natural gas prices and price differentials

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us 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 supply of crude oil in North America and internationally, 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 prolonged periods 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 without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

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

Availability and cost of capital or borrowing to maintain and/or fund 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. Additionally, from time to time, we may issue Common Shares or other securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

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 future capital expenditures, 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 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 at 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 such 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 are 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.

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 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 controlled by third parties. 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.

Public perception and its influence on the regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could have a material adverse effect on our financial condition, results of operations or prospects.

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, results of operations or prospects.

At present, Canada, the United States and Mexico are re-negotiating the North American Free Trade Agreement (" **NAFTA**"), with the United States threatening to withdraw from NAFTA if negotiations are not successful. We can not anticipate what the overall impact of the NAFTA re-negotiation 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, the timing of our abandonment and reclamation operations and the costs associated with such operations.

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, results of operations or 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 GHG emissions regulation (including carbon taxes) 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 Facilities 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. 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 us paying royalties at 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 may adversely impact our revenues in future periods. For more information about our commodity hedging program, see see *"General Description of our Business - 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: price inflation; scheduling delays; trucking and fuel costs; failure to maintain quality construction standards; and supply chain disruptions, including access to skilled labour. Natural gas, electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating and other costs that are susceptible to significant fluctuation.

Our 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 adjusted funds flow, 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"*.

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. In addition, 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 reserves as at December 31, 2017 are estimated using forecast prices and costs as set forth under "*Statement of Reserves Data - Pricing Assumptions*". If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in the Baytex Reserves Report, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. 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. It is not certain that we will resolve the contingencies applicable to our contingent resources allowing us to produce all or 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 and increase our costs.

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; 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; water handling and availability; 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 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.

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. In December 2015, the Government of the United States repealed its ban on crude oil exports to the international market. Only exports to embargoed or sanctioned countries continue to require authorization from the U.S. Department of Commerce.

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, which 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 license 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 Railroad Commission of Texas ("**RRC**"). 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.

NAFTA is currently being re-negotiated under a threat of withdrawal by the United States and it is not yet clear how our industry will be affected.

Royalties and Incentives

In addition to federal regulation, each province in Canada and each state in the United States has legislation and regulations that govern royalties, production rates and other matters. The royalty regime is a significant factor in the profitability of hydrocarbon production. Royalties payable on production from lands other than Crown lands in Canada and federal and state lands in the United States are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain taxes and royalties. Royalties from production on Crown lands in Canada and federal and state lands in the United States are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced.

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

Land Tenure

In western Canada, the rights to crude oil and natural gas 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 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 response to a number of insolvencies, Alberta and Saskatchewan have made their liability management programs more stringent in recent years. In particular, a licensee is held to a higher standard when accepting the transfer of licensees from a third party. This has reduced the number of parties which can acquire assets.

In Texas, each operator of a well must file a bond, letter of credit, or cash deposit with the 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 the 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. 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. At the state level in Texas, the TCEQ regulates public health and natural resources, including air, water and waste, and the RRC regulates the stewardship of oil and natural gas resources, along with some aspects of environmental protection and safety related to extraction of those resources. The RRC regulations establish environmental remediation and reporting criteria for the cleanup of oil and produced water spills.

Climate Change Regulation

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 also signed the Paris Agreement in December 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. In 2017, the United States announced that it would withdraw from the Paris Agreement at its first opportunity in 2020 and would, in the meantime, cease implementing the pledges made in connection with 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 effective January 1, 2017, which increased to $30/tonne as of January 1, 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.

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.

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 or 2017. 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. 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, 2017. Also see *"Material Contracts"*.

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

Moody's Investor Service Inc. ("**Moody's**") has assigned Baytex a corporate family credit rating of B3, assigned our Senior Notes a credit rating of Caa1 and stated that our rating outlook is stable. 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.

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 2017.

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
2017						
January	6.97	5.12	157,273,832	5.19	3.92	46,224,055
February	5.38	4.57	124,943,730	4.10	3.47	41,966,528
March	5.19	4.02	151,580,105	3.88	3.01	50,986,021
April	4.82	3.83	108,625,828	3.63	2.80	32,512,231
May	4.71	3.82	120,508,639	3.50	2.80	34,802,182
June	4.13	2.87	140,710,138	3.07	2.15	42,462,225
July	3.66	2.76	107,492,483	2.95	2.13	23,628,107
August	3.67	2.88	83,218,633	2.92	2.31	31,831,165
September	3.93	3.08	80,127,009	3.16	2.50	26,389,364
October	3.83	2.95	81,641,163	3.06	2.30	25,504,445
November	4.38	3.52	172,000,696	3.44	2.75	48,741,471
December	4.59	3.45	107,702,386	3.61	2.68	39,403,127

DIRECTORS AND OFFICERS

The following table sets forth the name, municipality of residence, age as at December 31, 2017, 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
Mark R. Bly[3] Incline Village, Nevada	58	Director	Independent Businessman
James L. Bowzer[3] Calgary, Alberta	57	Director	Independent Businessman
John A. Brussa [3] [4] Calgary, Alberta	60	Director	Chairman, Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	62	Director and Chairman of the Board	Chairman of the Board, Baytex
Edward Chwyl [2] [3] Victoria, B.C.	74	Director	Independent Businessman
Trudy M. Curran [1] [2] [4] Calgary, Alberta	55	Director	Independent Businesswoman
Naveen Dargan [1] [2] Calgary, Alberta	60	Director	Independent Businessman
R.E.T. (Rusty) Goepel [4] Vancouver, B.C.	75	Director	Senior Vice President, Raymond James Ltd.
Gregory K. Melchin [1][4] Calgary, Alberta	64	Director	Independent Businessman
Mary Ellen Peters [1] [2] Sarasota, Florida	61	Director	Independent Businesswoman
Dale O. Shwed [3] Calgary, Alberta	59	Director	President and Chief Executive Officer, Crew Energy Inc.
Kendall D. Arthur Calgary, Alberta	37	Vice President, Lloydminster and Conventional Business Units	Vice President, Lloydminster and Conventional Business Units, Baytex
Geoffrey J. Darcy Calgary, Alberta	55	Senior Vice President, Marketing	Senior Vice President, Marketing, Baytex
Murray J. Desrosiers Calgary, Alberta	48	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary, Baytex
Brian G. Ector Calgary, Alberta	49	Senior Vice President, Capital Markets and Public Affairs	Senior Vice President, Capital Markets and Public Affairs, Baytex
Rodney D. Gray Calgary, Alberta	46	Chief Financial Officer	Chief Financial Officer, Baytex
Ryan M. Johnson Calgary, Alberta	41	Vice President, Peace River Business Unit	Vice President, Peace River Business Unit, Baytex

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
Chad L. Kalmakoff Calgary, Alberta	41	Vice President, Finance	Vice President, Finance, Baytex
Edward D. LaFehr Calgary, Alberta	58	President and Chief Executive Officer	President and Chief Executive Officer, Baytex
M. Scott Lovett Calgary, Alberta	44	Vice President, Business Development	Vice President, Business Development, Baytex
Richard P. Ramsay Calgary, Alberta	54	Chief Operating Officer	Chief Operating Officer, Baytex
Gregory A. Sawchenko Calgary, Alberta	45	Vice President, Land	Vice President, Land, Baytex
Gregory M. Zimmerman Houston, Texas	59	Vice President, U.S. Business Unit	Vice President, U.S. Business Unit, Baytex

Notes:
(1) Member of our Audit Committee.
(2) Member of our Human Resources and Compensation Committee.
(3) Member of our Reserves Committee.
(4) Member of our Nominating and Governance Committee.
(5)Baytex's directors hold office until the next annual general meeting of Shareholders or until each director's successor is appointed or elected pursuant to the ABCA. On December 7, 2017, Baytex announced that Mr. Brussa and Mr. Goepel would not be standing for re-election.

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

Mark R. Bly became a director of Baytex on November 1, 2017. Mr. Bly is an independent businessman with over 35 years of experience in the oil and gas industry, primarily with BP, a global producer of oil and gas. Since retiring from BP in 2013, Mr. Bly has worked with private oil and gas production and service companies serving as an executive, a board member and advisor. At BP, Mr. Bly held various senior leadership roles in its domestic and international operations, including leading the North American onshore unit, Group Vice President for approximately 25% of BP's global production, and Executive Vice President of Group Safety and Operational Risk. Mr. Bly holds a Master of Science degree in structural engineering from the University of California, Berkeley and a Bachelor of Science degree in civil engineering from the University of California, Davis.

James L. Bowzer became a director of Baytex on September 4, 2012. He served as Chief Executive Officer of Baytex from September 2012 to May 2017 and as as President of Baytex 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 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 serves on the Executive Committee of the Calgary chapter of the Institute of Corporate Directors, is a member of the board and the Finance and Audit Committee of Kids Cancer Care Foundation of Alberta and is a member of the Alberta Securities Commission and serves on its Human Resources and Compensation Committee. 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. 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. 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 CFA Society Calgary.

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.

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 on May 4, 2017 was appointed Chief Executive Officer and became a director. 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.

M. Scott Lovett was appointed Vice President, Business Development of Baytex on September 5, 2017. Mr. Lovett is a professional engineer and has over 20 years of experience in the oil and gas industry, including reservoir evaluations, acquisitions and divestments, business planning, and strategic analysis. From March 2014 to September 2017, he held a number of positions of increasing responsibility at Eagle Energy Inc., including Executive Vice President, Business Development. From September 2011 to March 2014, he was an officer of Native American Resource Partners, initially serving as Senior Vice President and then Chief Operating Officer. Prior thereto, he held various engineering and management roles at GLJ Petroleum Consultants Ltd. and Enerplus Corporation. Mr. Lovett holds a Bachelor and Master in Science degrees in Chemical Engineering and a Master in Business Administration, all from the University of Calgary.

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. 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, 2018, the directors and officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 3,788,456 Common Shares, representing approximately 1.6 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, Twin Butte Energy Ltd. (a public oil and gas exploration and production company) which was placed in receivership on September 1, 2016 and Virginia Hills Oil Corp. (a public oil and gas exploration and production company) which consented to the appointment of a receiver over all of its current and future assets, undertakings and properties on February 13, 2017. Mr. Brussa resigned as a director of Calmena on June 30, 2014, Enseco on October 14, 2015, Argent on June 30, 2016, Twin Butte on September 1, 2016 and Virgina Hills on February 24, 2017.

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 ABCA. The ABCA 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 ABCA.

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 2017 and 2016:

	Aggregate fees billed ($000s)	
	2017	2016
Audit Fees	$ 723	$ 700
Audit-Related Fees	11	77
Tax Fees	—	13
All Other Fees	5	—
Total	$ 739	$ 790

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 2017 and 2016 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 and are not reported as Audit Fees. Audit related fees for 2016 also include fees for the review of a prospectus related to a public offering of common shares in 2016.

Tax Fees: Tax fees in 2016 were incurred to obtain a transfer pricing study regarding the provision of cross border services to Baytex USA.

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 (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 that may be applied 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.

TRANSFER AGENT AND REGISTRAR

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.

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, March 9, 2015 and February 20, 2018);

(c) Debt Indenture #2 (filed on SEDAR on June 20, 2014) and supplemental indentures thereto (filed on SEDAR on August 13, 2014, September 9, 2014 and February 20, 2018); 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*.

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.

KPMG LLP are the auditors of the Corporation and have confirmed with respect to the Corporation, that they are independent within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations, and also that they are independent accountants with respect to the Corporation under all relevant US professional and regulatory standards.

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.

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 3, 2018. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2017 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 paragraph, please contact:

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

APPENDIX A

CONTINGENT RESOURCE ESTIMATES

We commissioned Sproule to conduct an evaluation of our contingent resources in Lloydminster, Peace River, North East 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, 2017, prepared in accordance with the Canadian definitions, standards and procedures contained in the COGE Handbook and based on the Sproule December 31, 2017 forecast prices and costs set forth under "*Statement of Reserves Data - Pricing Assumptions*" 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 Oil and Natural Gas Contingent Resources as of December 31, 2017 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)
9,803	8,050	15,715	12,411	38	29	3,523	3,237

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)
7,061	5,205	2,401	1,774	10,304	7,568	37,322	29,271

Note:
(1) Based on the reports prepared by Sproule and Ryder Scott effective December 31, 2017.

Summary of Risked Net Present Value of Future Net Revenue (Contingent Resources) as of December 31, 2017 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	846	435	236	130	69	628	315	163	82	36

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, 2017.

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	Pre-Development	127	2019-2021	Cyclic steam stimulation
Peace River, Lloydminster and North East Alberta	Heavy Oil	Pre-Development	227	2018-2023	Horizontal, vertical and multilateral well and polymer flood development
Pembina	Light & Medium Oil, Natural Gas	Pre-Development	5	2022	Horizontal well development with multi-stage fracturing completion
Eagle Ford	Tight Oil, Shale Gas and NGL	Pre-Development	128	2018-2028	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	86
Peace River, Lloydminster and North East Alberta	Heavy Oil	15	88%	13	46
Pembina	Light & Medium Oil, Natural Gas	1	90%	1	4
Eagle Ford	Tight Oil, Shale Gas and NGL	14	80%	11	100
Total		49		41	236

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 North East 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 Peace River heavy oil development pending contingent resources also includes Bluesky volumes to be recovered through horizontal heavy oil polymer flood technology. Using the volumetric data obtained from a geological review of mobility and net pay mapping, an estimate of the OOIP was calculated. The recovery factor was estimated based on the performance of immediate offset analogous polymer flood wells.

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	944	58%	552
Peace River, Lloydminster and North East Alberta	Heavy Oil	32	57%	18
Pembina	Light & Medium Oil, Natural Gas	12	55%	7
Eagle Ford	Tight Oil, Shale Gas and NGL	135	50%	67
Total		1,123		644

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 North East 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 North East 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, North East 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, North East 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) *"Edward D. LaFehr"*
Edward D. LaFehr
President and 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 9, 2018

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, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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, 2017, 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, 2017, 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, 2017). Prepared: August 2017 to February 2018	Canada	—	$1,579,768	—	$1,579,768

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, 2017	Canada	26,276	—	$135,276	$135,276

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, 2017	Canada	574,414

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 9, 2018.

Sproule Unconventional Limited

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

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

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 audited Baytex's internal evaluation of the contingent resources data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, 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, 2017, 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, 2017, 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, 2017). Prepared: August 2017 to February 2018	United States of America	—	$2,510,824	—	$2,510,824

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, 2017	United States of America	11,047	—	$100,333	$100,333

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, 2017	United States of America	67,363

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 9, 2018.

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

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

Houston, Texas, USA
March 9, 2018

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 99.4

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, Edward D. LaFehr, 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 9, 2018 BAYTEX ENERGY CORP.

/s/ Edward D. LaFehr
Name: Edward D. LaFehr
Title: President and 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 9, 2018 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, 2017, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Edward D. LaFehr, 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 9, 2018 BAYTEX ENERGY CORP.

/s/ *Edward D. LaFehr*
Name: Edward D. LaFehr
Title: President and 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, 2017, 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 9, 2018 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 use of our reports, each dated March 5, 2018, with respect to the consolidated financial statements and the effectiveness of internal control over financial reporting included in this annual report on Form 40-F.

We also consent to the incorporation by reference of such reports 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.

/s/ KPMG LLP

Chartered Professional Accountants
March 9, 2018
Calgary, Canada

Exhibit 99.9

CONSENT OF INDEPENDENT ENGINEERS

We refer to: (i) our report dated January 22, 2018 and effective December 31, 2017, evaluating the proved and probable petroleum and natural gas reserves attributable to Baytex Energy Corp. and its affiliates (collectively, the "Company"), which is entitled "Evaluation of the P&NG Reserves of Baytex Energy Corp. in Canada (As of December 31, 2017)"; (ii) our report dated February 16, 2018 and effective December 31, 2017, consolidating the proved and probable and for the United States the possible petroleum and natural gas reserves attributable to the Company, 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, 2017)"; (iii) our assessment dated February 12, 2018 and effective December 31, 2017, evaluating the contingent resources attributable to the Company in Canada, which is entitled "Evaluation of the Contingent Resources of Baytex Energy Corp. in Canada (As of December 31, 2017)"; (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, 2017 dated March 9, 2018, 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 9, 2018

Exhibit 99.10

CONSENT OF INDEPENDENT ENGINEERS

We refer to: (i) our report dated February 1, 2018 and effective December 31, 2017, 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. Estimated Future Reserves and Income Attributable to Certain Leasehold Interests NI 51-101 Forecast Economic Parameters Canadian Currency as of December 31, 2017"; and (ii) our letter report dated February 1, 2018 and effective December 31, 2017, 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 NI 51-101 Forecast Economic Parameters Canadian Currency as of December 31, 2017"; (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, 2017 dated March 9, 2018, 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.

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

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

Houston, Texas, United States of America
March 9, 2018

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2017

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, 2017 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, 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
Revisions of previous estimates	18,843	6,666	(19,264)	11,336	—	18,485	30,180	6,666	(779)
Improved recovery	576	—	100	5,275	—	10,854	5,851	—	10,954
Purchases	3,962	—	1,855	—	—	—	3,962	—	1,855
Extensions and discoveries	562	—	2,561	—	—	—	562	—	2,561
Production	(7,982)	(309)	(11,350)	(7,616)	—	(13,529)	(15,598)	(309)	(24,879)
Sales of minerals in place	(1,793)	—	(2)	—	—	—	(1,793)	—	(2)
December 31, 2017	30,850	12,115	45,974	94,219	—	168,624	125,070	12,115	214,598
Net proved developed reserves									
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
End of year 2017	20,790	7,376	29,141	33,978	—	67,150	54,768	7,376	96,291

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 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 2017 and 2016.

	Commodity Pricing	
	2017	**2016**
WTI crude (US$/bbl)	$ 51.30	$ 42.75
Canadian Light Sweet (Cdn$/bbl)	$ 63.56	$ 52.08
Western Canadian Select (WCS)[(1)] (Cdn$/bbl)	$ 50.78	$ 38.13
AECO-C spot price (Cdn$/mmbtu)	$ 2.34	$ 2.17
Henry Hub (US$/mmbtu)	$ 3.07	$ 2.55
Exchange rate (US$/Cdn$)	0.7681	0.7350

(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)	**2017**	**2016**	**2017**	**2016**	**2017**	**2016**
Future cash inflows	$ 1,583,988	$ 625,763	$ 5,349,200	$ 3,823,293	$ 6,933,188	$ 4,449,056
Future production costs	(823,736)	(356,876)	(1,747,864)	(1,444,893)	(2,571,600)	(1,801,769)
Future development costs	(270,877)	(119,549)	(1,331,710)	(1,250,620)	(1,602,587)	(1,370,169)
Future income taxes	—	—	(81,038)	(17,018)	(81,038)	(17,018)
Future net cash flows	489,375	149,338	2,188,588	1,110,762	2,677,963	1,260,100
Deduct: 10% annual discount factor	(134,170)	(35,103)	(1,043,340)	(558,359)	(1,177,510)	(593,462)
Standardized measure	$ 355,205	$ 114,235	$ 1,145,248	$ 552,403	$ 1,500,453	$ 666,638

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, 2017 (thousands of Canadian dollars)		Canada		United States		Total
Balance, beginning of year	$	114,324	$	552,403	$	666,727
Sales, net of production costs		(178,560)		(350,787)		(529,347)
Net change in prices and production costs related to future production		90,041		346,588		436,629
Changes in previously estimated production costs incurred during the period		(109,531)		(137,635)		(247,166)
Development costs incurred during the period		106,156		212,993		319,149
Extensions, discoveries and improved recovery, net of related costs		13,991		84,601		98,592
Revisions of previous quantity estimates		334,527		476,667		811,194
Sales of reserves in place		(28,872)		—		(28,872)
Purchases of reserves in place		9,524		—		9,524
Accretion of discount		3,605		38,791		42,396
Net change in income taxes		—		(78,373)		(78,373)
Balance, end of year	$	355,205	$	1,145,248	$	1,500,453

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

Capitalized Costs Relating to Petroleum and Natural Gas Producing Activities

As at December 31, 2017 (thousands of Canadian dollars)		Canada		United States		Total
Proved properties	$	3,639,640	$	4,292,687	$	7,932,327
Unproved properties		112,651		160,323		272,974
Total capital costs		3,752,291		4,453,010		8,205,301
Accumulated depletion and depreciation		(2,141,644)		(1,832,374)		(3,974,018)
Net capitalized costs	$	1,610,647	$	2,620,636	$	4,231,283

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

Baytex Energy Corp.
Supplemental Disclosures about Extractive Activities - Oil and Gas (unaudited)
December 31, 2017

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

For year ended December 31, 2017 (thousands of Canadian dollars)		Canada		United States		Total
Property acquisition costs						
Proved properties	$	136,007	$	—	$	136,007
Unproved properties		—		—		—
Development costs [1]		108,939		216,034		324,973
Exploration costs [2]		7,118		—		7,118
Total	$	252,064	$	216,034	$	468,098

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
Development costs [1]		21,184		204,552		225,736
Exploration costs [2]		4,689		—		4,689
Total	$	26,029	$	204,552	$	230,581

(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, 2017 (thousands of Canadian dollars except per boe amounts)		Canada		United States		Total
Petroleum and natural gas revenues, net of royalties	$	411,567	$	438,075	$	849,642
Less:						
Operating costs, production and mineral taxes		181,995		87,288		269,283
Transportation and blending expense		84,997		—		84,997
Depreciation and depletion		200,996		280,933		481,929
Operating loss		(56,421)		69,854		13,433
Income tax recovery		—		(1,085)		(1,085)
Results of operations [1]	$	(56,421)	$	70,939	$	14,518
Depletion rate per net boe		19.74		28.46		24.03

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 loss		(132,956)		(51,958)		(184,914)
Income tax recovery		(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

(1) Excludes corporate overhead and interest costs.