BAYTEX

ENERGY CORP.

ANNUAL INFORMATION FORM

2013

MARCH 25, 2014

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SELECTED TERMS

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

Entities

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

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

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

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

Baytex USA means Baytex Energy USA Ltd.

Board of Directors means the board of directors of Baytex.

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

OPEC means the Organization of the Petroleum Exporting Countries.

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

SEC means the United States Securities and Exchange Commission.

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

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

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

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

Independent Engineering

COGE Handbook means the Canadian Oil and Gas Evaluation Handbook.

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

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

Sproule Report means the report prepared by Sproule dated February 28, 2014 entitled "*Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2013)*".

Securities and Other Terms

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

2022 Debentures means our $300 million 6.625% series C senior unsecured debentures due July 19, 2022 and issued pursuant to the Debenture Indenture.

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

Canadian GAAP means generally accepted accounting principles in Canada, which is consistent with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Common Shares means the common shares of Baytex.

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

Credit Facilities means, collectively, the $40 million extendible operating loan facility that Baytex Energy has with a chartered bank and the $810 million extendible syndicated loan facility that Baytex Energy has with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). Unless extended, the Credit Facilities will mature on June 14, 2017.

Debenture Indenture means the amended and restated trust indenture among us, as issuer, Baytex Energy, Baytex Partnership, Baytex Marketing Ltd., Baytex USA, the Baytex Commercial Trusts and Baytex Finance Company Ltd., 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 and December 19, 2012.

Debentures means, collectively, the 2021 Debentures and the 2022 Debentures.

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

SAGD means steam-assisted gravity drainage.

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

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

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

ABBREVIATIONS

Oil and Natural Gas Liquids

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
GJ	gigajoule

Other

AECO	the natural gas storage facility located at Suffield, Alberta
BOE or boe	barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one bbl of oil. **BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.**
Mboe	thousand barrels of oil equivalent
MMboe	million barrels of oil equivalent
boe/d	barrels of oil equivalent per day
WTI	West Texas Intermediate
API	the measure of the density or gravity of liquid petroleum products derived from a specific gravity
$ Million	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; the portion of our funds from operations to be allocated to our capital program; our ability to maintain production levels by investing approximately two-thirds of our internally generated funds from operations; our ability to grow our reserve base and add to production levels through exploration and development activities complemented by strategic acquisitions; the anticipated benefits from the acquisition (the "**Acquisition**") of Aurora Oil & Gas Limited ("**Aurora**"), including our belief that the Acquisition will be an excellent fit with our business model and will provide shareholders with exposure to low-risk, repeatable, high-return projects with capital efficiencies; our expectation that the Aurora assets have infrastructure in place to provide low-risk annual production and that such assets will provide material production, long-term growth and high quality reserves with upside potential; our expectations regarding the effect of well downspacing, improving completion techniques and new development targets on the reserves potential of the Aurora assets; the timing of completion of the Acquisition; our plan to establish new revolving credit facilities and a term loan for us and a borrowing base facility for Aurora's U.S. subsidiary following closing of the Acquisition; payment of the purchase price for the Acquisition, including the use of proceeds from the subscription receipt financing and our plan to draw on the new revolving credit facilities and term loan; our petroleum and natural gas reserves, including the volume thereof and the present value of the future net revenue to be derived therefrom; the estimates of contingent resources for our oil resource plays at Peace River, northeast Alberta, North Dakota and the Gemini SAGD project, including the volume thereof; development plans for our properties, including number of potential drilling locations, number of wells to be drilled in 2014, initial production rates from new wells and recovery factors; the development potential of our oil sands leases at Angling Lake (Cold Lake) for both primary (cold) and thermal recovery methods; our plans for a SAGD project at Gemini (Angling Lake (Cold Lake)), including the timing of initial production from the pilot project; our plan to expand the waterflood at Carruthers in 2014; our SAGD project at Kerrobert, including the number of potential well pair and infill well drilling locations and well costs; our plan for a commercial waterflood project at Tangleflags; our heavy oil resource play at Peace River, including the resource potential of our undeveloped land, initial production rates from new wells under primary recovery methods and the ability to recover incremental reserves using waterflood and polymer flood recovery methods; our thermal operations at Cliffdale, including our assessment of the production and steam-oil ratio performance of Pad 1, the timing of commencing steam injection at Pad 2 and plans to expand the program and build a central processing facility; our light oil resource play in North Dakota, including our assessment of the number of wells to be drilled, initial production rates from new wells and average recoveries per well; our plan to drill a well in the Weston and Niobrara Counties of Wyoming and the estimated cost thereof; our expectation regarding the payment of cash income taxes prior to 2015; our working interest production volume for 2014; the existence, operation and strategy of our risk management program; our dividend policy and level; funding sources for development capital expenditures and dividend payments; and the impact of existing and proposed governmental and environmental regulation. Cash dividends on our Common Shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time.

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

These forward-looking statements are based on certain key assumptions regarding, among other things: the receipt of regulatory, court and shareholder approvals for the Acquisition; our ability to execute and realize on the anticipated benefits of the acquisition of Aurora; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oils; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the acquisition of Aurora may not be completed on the terms contemplated or at all; failure to realize the anticipated benefits of the acquisition of Aurora; closing of the acquisition of Aurora could be delayed or not completed if we are unable to obtain the necessary regulatory, court and shareholder approvals for the Acquisition or any other approvals required for completion or, unless waived, some other condition to closing is not satisfied; failure to put in place a borrowing base facility for Aurora's U.S. subsidiary following completion of the Acquisition; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; a downgrade of our credit ratings; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in government regulations that affect the oil and gas industry; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.

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

The above summary of assumptions and risks related to forward-looking information in this Annual Information Form has been provided in order to provide Shareholders and potential investors with a more complete perspective on our current and future operations (if the acquisition of Aurora is completed) and such information may not be appropriate for other purposes. There is no representation by us that actual results achieved during the forecast period will be the same in whole or in part as those forecast and we do not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law. The forward-looking statements contained in this Annual Information Form are expressly qualified by this cautionary statement.

Contingent Resources

This Annual Information Form contains estimates of the volumes of the "contingent resources" for our oil resource plays in the Bluesky in the Peace River area of Alberta, the Mannville group in northeast Alberta and the Bakken/Three Forks in North Dakota as of December 31, 2013 and for the Gemini SAGD project in Cold Lake, Alberta, as of December 31, 2012. These estimates were prepared by independent qualified reserves evaluators.

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

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

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

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

There is no certainty that it will be commercially viable to produce any portion of the contingent resources or that we will produce any portion of the volumes currently classified as contingent resources. The estimates of contingent resources involve implied assessment, based on certain estimates and assumptions, that the resources described exists in the quantities predicted or estimated and that the resources can be profitably produced in the future.

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

Description of Funds from Operations

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

For a reconciliation of funds from operations to cash flow from operating activities, see our "*Management's Discussion and Analysis of operating and financial results for the year ended December 31, 2013*" which is accessible on the SEDAR website at *www.sedar.com*.

New York Stock Exchange

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

Access to Documents

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

BAYTEX ENERGY CORP.

General

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

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

Our head and principal office is located at Suite 2800, Centennial Place, East Tower, 520 – 3rd Avenue S.W., Calgary, Alberta, Canada, T2P 0R3. Our registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, Canada, T2P 1G1.

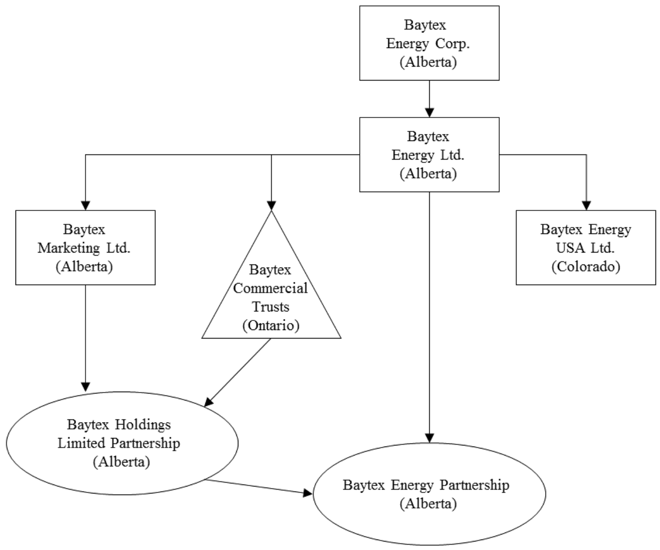
Inter-Corporate Relationships

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

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

Our Organizational Structure

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



GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

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

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

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

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

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

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

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

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

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

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

On February 6, 2014, we entered an agreement to acquire all of the ordinary shares of Aurora Oil & Gas Ltd. ("**Aurora**") for A$4.10 (Australian dollars) per share by way of a scheme of arrangement under Part 5.1 of the Corporations Act 2001 (Australia) (the "**Arrangement**"). The total purchase price for Aurora is estimated at $2.6 billion (including the assumption of approximately $0.7 billion of indebtedness). Aurora's primary asset is 22,200 net contiguous acres in the Sugarkane Field located in South Texas in the core of the liquids-rich Eagle Ford shale. Aurora's fourth quarter 2013 gross production was 24,678 boe/d (82% liquids) of predominantly light, high-quality crude oil. The Sugarkane Field has been largely delineated with infrastructure in place which is expected to facilitate low-risk future annual production growth. In addition, these assets have significant future reserves upside potential from well downspacing, improving completion techniques and new development targets in additional zones.

The Arrangement is subject to a number of customary closing conditions, including the receipt of required regulatory approvals and court approvals, as well as the approval of the shareholders of Aurora. Regulatory approvals include approval of the Australian Foreign Investment Review Board and the applicable approvals required under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (the "**HSR**"), as amended. On March 4, 2014, we received approval from the Federal Trade Commission with respect to the HSR. The Arrangement must be approved by: (i) at least 75% of the votes cast by Aurora shareholders; and (ii) by a majority, in number, of the Aurora shareholders who cast votes. The Arrangement is expected to close in the first half of June 2014.

To finance the acquisition of Aurora, we completed a subscription receipt financing and entered into a commitment letter with a Canadian chartered bank to establish new credit facilities, as described in more detail below.

On February 6, 2014, we entered into an agreement, on a "bought-deal" basis, with a syndicate of underwriters for an offering of 33,420,000 subscription receipts ("**Subscription Receipts**") at a price of $38.90 per Subscription Receipt with each Subscription Receipt entitling the holder thereof to receive, on closing of the Arrangement, one Common Share for aggregate gross proceeds of approximately $1.3 billion. We granted the underwriters an over-allotment option to purchase, on the same terms, up to an additional 5,013,000 Subscription Receipts. At the closing of the offering on February 24, 2014, we issued 38,433,000 Subscription Receipts for aggregate gross proceeds of approximately $1.5 billion, which have been placed in escrow.

On February 6, 2014, we entered into a commitment letter with a Canadian chartered bank for the provision of new revolving credit facilities in the amount of $1.0 billion (to replace the Credit Facilities of Baytex Energy), new non-revolving facilities consisting of a $200 million two-year facility and a $1.3 billion equity bridge loan and a new borrowing base facility in the amount of US$300 million for a U.S. subsidiary of Aurora (to be established upon closing of the Arrangement as a replacement for an existing facility). As a result of the completion of the Subscription Receipt financing, the $1.3 billion equity bridge loan is no longer available.

Significant Acquisitions

During the year ended December 31, 2013, we did not complete any acquisitions for which disclosure was required under Part 8 of National Instrument 51-102.

RISK FACTORS

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

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

Risks Relating to Our Business and Operations

Oil and natural gas prices are volatile; declines in oil and natural gas prices will adversely affect us

Our financial condition is substantially dependent on, and highly sensitive to the prevailing prices of crude oil and natural gas. Significant declines in crude oil or natural gas prices could have a material adverse effect on our operations and financial condition and the value and amount of our reserves.

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

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

Fluctuations in the price of commodities and associated price differentials may impact the value of our assets, our ability to maintain our business and to fund growth projects. Prolonged periods of commodity price volatility may also negatively impact our ability to meet guidance targets and meet all of our financial obligations as they come due. Any substantial or extended decline in these commodity prices may result in a delay or cancellation of existing or future drilling, development or construction programs, or curtailment in production at some properties, result in unutilized long-term transportation commitments and a reduction in the volumes 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 property, plant and equipment could be subject to downward revisions, and net earnings could be adversely affected.

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

We deliver our products through gathering, processing and pipeline systems, some of which we do not own. The lack of access to capacity in any of the gathering, processing and pipeline systems, and in particular the processing facilities, could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

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

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

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 affect on our financial condition, results of operations and future growth, potentially resulting in a decrease in dividends to Shareholders and/or the market price of the Common Shares.

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

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

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

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a defined hedging program. We also use derivative instruments in various operational markets to optimize our supply or production chain. The terms of these arrangements may limit the benefit to us of favourable changes in these factors and may also result in royalties being paid on a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. For more information in relation to our commodity hedging program, see "*Description of Our Business and Operations – Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Gas Information – Forward Contracts*".

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

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. Should the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future Shareholders.

Our ability to obtain additional capital is dependent on, among other things, interest in investments in the energy industry in general and interest in our securities in particular and our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

Our bank credit facilities will need to be renewed prior to June 14, 2017 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition

Our existing Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. We currently have Credit Facilities in the amount of $850 million. In the event that the Credit Facilities are not extended before June 14, 2017, indebtedness under the Credit Facilities will be repayable on June 14, 2017. The interest charged on the Credit Facilities is calculated based on a sliding scale ratio of our debt to earnings ratio. Repayment of all outstanding amounts under the Credit Facilities may be demanded on relatively short notice if an event of default occurs, which is continuing. If this occurs, we may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse affect on our business, and dividends to Shareholders may be materially reduced. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms.

As at December 31, 2013, our outstanding indebtedness included US$150 million of 2021 Debentures which mature on February 17, 2021 and $300 million of 2022 Debentures which mature on July 19, 2022. We intend to fund these debt maturities with our existing Credit Facilities. In the event we are unable to refinance our debt obligations, it may impact our ability to fund our ongoing operations and to pay dividends.

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

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

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

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

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

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

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

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

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

The oil and gas industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights.

We rely on fresh water, which is obtained under government licenses to provide domestic and utility water for certain of our operations. There can be no assurance that the licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that we will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, new projects or the expansion of existing projects may be dependent on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to us, or at all, or that such additional water will in fact be available to divert under such licenses.

We use hydraulic fracturing in our operations. With the increase in the use of fracture stimulations in horizontal wells there is increased communication between the oil and natural gas industry and a wider variety of stakeholders regarding the responsible use of this technology as it relates to the environment. This increased attention to fracture stimulations may result in increased regulation or changes of law which may make the conduct of our business more expensive or prevent us from conducting our business as currently conducted. Any new laws, regulation or permitting requirements regarding hydraulic fracturing could lead to operational delay or increased operating costs or third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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

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

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

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

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

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

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

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

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

If we fail to acquire, develop or find additional crude oil and natural gas reserves, our reserves and production will decline materially from their current levels and therefore our business, financial condition, results of operations and cash flows are highly dependent upon successfully producing current reserves and acquiring, discovering or developing additional reserves.

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

Acquiring, developing and exploring for oil and natural gas involves many hazards. We have not insured and cannot fully insure against all risks related to our operations

Our crude oil and natural gas operations are subject to all of the risks normally incidental to: (i) the storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) the operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; blowouts; fires; explosions; equipment failures and other accidents; gaseous leaks; uncontrollable 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 environmental risks.

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

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

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

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

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

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

Some of our heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as cyclic steam stimulation and steam-assisted gravity drainage, are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on cyclic steam stimulation, steam-assisted gravity drainage or other new technologies to become uneconomic, which could have an adverse affect on our financial condition. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

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

The oil and gas industry is highly regulated and changes in environmental, health and safety regulations may impose restrictions or costs on our business which may adversely affect our financial condition and our ability to maintain dividends

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

Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties and failure to comply with environmental regulations may result in the imposition of fines or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Although it is not expected that the costs of complying with environmental regulations will have a material adverse affect 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 regulations or the modification of existing regulations affecting the oil and gas industry generally could reduce demand for crude oil and natural gas, result in stricter standards and enforcement, larger fines and liability, and increased capital expenditures and operating costs, which could have a material adverse affect on our financial condition or results of operations and prospects. See "*Industry Conditions – Environmental Regulation*".

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

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

The implementation of strategies for reducing greenhouse gases may impose restrictions or costs on our business which may adversely affect our financial condition and our ability to maintain dividends

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with greenhouse gas emissions legislation that is enacted in jurisdictions where we have operations. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in greenhouse gas emissions from 2005 levels by 2020. These greenhouse gas emission reduction targets are not binding, however.

Some of our significant facilities may ultimately be subject to future regional, provincial, state and/or federal climate change regulations to manage greenhouse gas emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict either the nature of those requirements or the impact on us and our operations and financial condition.

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

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

Our future oil and natural gas reserves and production, and therefore our funds from operations, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. Without reserves additions through exploration, acquisition or development activities, our reserves and production may decline over time as reserves are produced. The business of exploring for, developing or acquiring reserves is capital intensive.

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

We also distribute a significant proportion of our funds from operations to Shareholders rather than reinvesting in reserves additions. Accordingly, if external sources of capital become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. In addition, we may be unable to find and develop or acquire additional reserves to replace our crude oil and natural gas production at acceptable costs.

Risks Relating to Ownership of our Securities

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

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

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

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

The timing and amount of capital expenditures will directly affect the amount of income available to pay dividends to our Shareholders. Dividends may be reduced, or even eliminated, at times when significant capital or other expenditures are planned. To the extent that external sources of capital, including the issuance of additional

Common Shares, become limited or unavailable, our ability to make the necessary capital investments to maintain or expand oil and natural gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that we are required to use funds from operations to finance capital expenditures or property acquisitions, the cash we receive will be reduced, resulting in reductions to the amount of cash we are able to distribute to our Shareholders. A reduction in the amount of cash distributed to Shareholders may negatively affect the market price of the Common Shares.

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

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

Certain Risks for United States and other non-resident Shareholders

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

We are a corporation incorporated under the laws of the Province of Alberta, Canada and our principal office is located in Calgary, Alberta. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent reserve engineers), and all or a substantial portion of our assets and the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them 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 and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this Annual Information Form may not be comparable to United States standards.

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

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

There is additional taxation applicable to non-residents

The Tax Act imposes a withholding tax at the rate of 25% on the dividends paid by us to Shareholders who are non-residents of Canada, unless the rate is reduced under the provisions of a tax treaty between Canada and the non-resident Shareholder's jurisdiction of residence. These taxes may change from time to time. Where the non-resident Shareholder is a United States resident entitled to benefits under the Canada-United States Income Tax Convention, 1980 (the "**Treaty**"), the rate of Canadian withholding tax applicable to dividends is generally reduced to 15%. To qualify for this reduced rate, non-resident beneficial Shareholders must file certain documents with their broker (or, in the case of non-resident registered Shareholders, with our transfer agent) evidencing Treaty eligibility. Additionally, dividend income is subject to income tax under U.S. tax law. The American Taxpayer Relief Act, effective January 1, 2013, assigns a tax rate of 15% to qualified dividends received by taxpayers earning less than US$400,000 (individual), US$425,000 (head of household) and US$450,000 (married filing jointly). Taxpayers earning more than these amounts are subject to tax on qualified dividends at a rate of 20%.

There is a foreign exchange risk for non-resident Shareholders

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

DESCRIPTION OF OUR BUSINESS AND OPERATIONS

Overview

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

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

Baytex Energy Ltd.

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

Baytex Energy Partnership

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

Baytex Energy USA Ltd.

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

Personnel

As at December 31, 2013, we had 186 employees in our Calgary head office, 25 employees in our Denver office and 76 employees in our field operations.

Notes

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

Statement of Reserves Data and Other Oil and Natural Gas Information

The statement of reserves data and other oil and natural gas information set forth below is dated December 31, 2013. The statement is effective as of December 31, 2013 and the preparation date of the statement by Sproule is February 28, 2014. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Sproule in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by Sproule with an effective date of December 31, 2013 as contained in the Sproule Report. The reserves data summarizes our bitumen, crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any hedging activities. The Sproule Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101. Sproule was engaged by us to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves. See also "*Definitions and Other Notes to Reserves Data Tables*" below.

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

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

SUMMARY OF OIL AND NATURAL GAS RESERVES
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

CANADA

RESERVES CATEGORY	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)
PROVED:						
Developed Producing	41,526	30,985	7,422	6,719	4,229	3,627
Developed Non-Producing	8,944	7,404	3,491	3,083	28	24
Undeveloped	32,433	26,757	8,409	7,336	1,450	1,231
TOTAL PROVED	82,903	65,146	19,322	17,139	5,707	4,882
PROBABLE	42,644	34,141	82,564	66,117	3,424	2,759
TOTAL PROVED PLUS PROBABLE	125,547	99,287	101,886	83,256	9,131	7,640

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:						
Developed Producing	2,032	1,461	48,813	42,099	63,345	49,810
Developed Non-Producing	75	55	1,825	1,572	12,842	10,827
Undeveloped	965	675	17,678	13,229	46,203	38,203
TOTAL PROVED	3,073	2,191	68,316	56,900	122,390	98,840
PROBABLE	3,469	2,421	60,523	46,062	142,188	113,115
TOTAL PROVED PLUS PROBABLE	6,542	4,611	128,839	102,963	264,578	211,955

UNITED STATES

RESERVES CATEGORY	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)
PROVED:						
Developed Producing	-	-	-	-	5,900	4,331
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	-	-	24,342	19,790
TOTAL PROVED	-	-	-	-	30,242	24,122
PROBABLE	-	-	-	-	13,341	10,715
TOTAL PROVED PLUS PROBABLE	-	-	-	-	43,583	34,837

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:						
Developed Producing	-	-	7,270	5,138	7,111	5,188
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	-	-	34,079	27,706	30,022	24,408
TOTAL PROVED	-	-	41,349	32,845	37,134	29,596
PROBABLE	-	-	18,373	14,658	16,403	13,159
TOTAL PROVED PLUS PROBABLE	-	-	59,722	47,503	53,537	42,754

TOTAL

RESERVES CATEGORY	HEAVY OIL Gross (Mbbl)	HEAVY OIL Net (Mbbl)	BITUMEN Gross (Mbbl)	BITUMEN Net (Mbbl)	LIGHT AND MEDIUM OIL Gross (Mbbl)	LIGHT AND MEDIUM OIL Net (Mbbl)
PROVED:						
Developed Producing	41,526	30,985	7,422	6,719	10,129	7,958
Developed Non-Producing	8,944	7,404	3,491	3,083	28	24
Undeveloped	32,433	26,757	8,409	7,336	25,792	21,021
TOTAL PROVED	82,903	65,146	19,322	17,139	35,949	29,003
PROBABLE	42,644	34,141	82,564	66,117	16,765	13,474
TOTAL PROVED PLUS PROBABLE	125,547	99,287	101,886	83,256	52,714	42,477

RESERVES CATEGORY	NATURAL GAS LIQUIDS Gross (Mbbl)	NATURAL GAS LIQUIDS Net (Mbbl)	NATURAL GAS Gross (MMcf)	NATURAL GAS Net (MMcf)	TOTAL RESERVES Gross (Mboe)	TOTAL RESERVES Net (Mboe)
PROVED:						
Developed Producing	2,032	1,461	56,083	47,238	70,456	54,997
Developed Non-Producing	75	55	1,825	1,572	12,842	10,827
Undeveloped	965	675	51,757	40,936	76,226	62,611
TOTAL PROVED	3,073	2,191	109,665	89,745	159,524	128,436
PROBABLE	3,469	2,421	78,895	60,721	158,592	126,273
TOTAL PROVED PLUS PROBABLE	6,542	4,611	188,561	150,466	318,115	254,709

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

CANADA	**BEFORE INCOME TAXES DISCOUNTED AT (%/year)**				
RESERVES CATEGORY	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
PROVED:					
Developed Producing	1,834,611	1,570,961	1,384,793	1,246,196	1,138,834
Developed Non-Producing	396,448	310,251	249,035	204,183	170,432
Undeveloped	1,159,374	851,610	637,943	489,964	384,324
TOTAL PROVED	3,390,433	2,732,823	2,271,770	1,940,343	1,693,590
PROBABLE	3,949,953	2,163,413	1,321,102	869,835	602,643
TOTAL PROVED PLUS PROBABLE	7,340,385	4,896,236	3,592,872	2,810,178	2,296,233
UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	297,703	229,474	187,748	159,947	140,204
Developed Non-Producing	-	-	-	-	-
Undeveloped	1,021,816	584,122	349,675	213,119	128,558
TOTAL PROVED	1,319,519	813,596	537,424	373,066	268,763
PROBABLE	837,373	347,638	179,484	107,071	70,425
TOTAL PROVED PLUS PROBABLE	2,156,892	1,161,234	716,907	480,137	339,188
TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	2,132,314	1,800,435	1,572,541	1,406,143	1,279,038
Developed Non-Producing	396,448	310,251	249,035	204,183	170,432
Undeveloped	2,181,190	1,435,733	987,618	703,083	512,882
TOTAL PROVED	4,709,952	3,546,419	2,809,194	2,313,409	1,962,352
PROBABLE	4,787,326	2,511,052	1,500,585	976,906	673,069
TOTAL PROVED PLUS PROBABLE	9,497,278	6,057,470	4,309,779	3,290,315	2,635,421

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

CANADA	AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,725,841	1,481,873	1,310,049	1,182,267	1,083,296
Developed Non-Producing	293,071	228,300	182,457	148,971	123,841
Undeveloped	849,215	612,680	445,622	329,799	247,363
TOTAL PROVED	2,868,127	2,322,853	1,938,127	1,661,037	1,454,500
PROBABLE	2,958,729	1,592,099	948,477	604,184	400,857
TOTAL PROVED PLUS PROBABLE	5,826,856	3,914,953	2,886,605	2,265,220	1,855,357

UNITED STATES					
RESERVES CATEGORY					
PROVED:					
Developed Producing	208,294	163,902	136,712	118,509	105,495
Developed Non-Producing	-	-	-	-	-
Undeveloped	594,461	334,621	194,708	112,797	61,853
TOTAL PROVED	802,756	498,523	331,420	231,306	167,348
PROBABLE	487,161	201,801	104,528	62,941	42,032
TOTAL PROVED PLUS PROBABLE	1,289,917	700,324	435,947	294,248	209,380

TOTAL					
RESERVES CATEGORY					
PROVED:					
Developed Producing	1,934,135	1,645,774	1,446,761	1,300,777	1,188,791
Developed Non-Producing	293,071	228,300	182,457	148,971	123,841
Undeveloped	1,443,676	947,302	640,329	442,596	309,215
TOTAL PROVED	3,670,882	2,821,376	2,269,547	1,892,343	1,621,848
PROBABLE	3,445,891	1,793,900	1,053,005	667,125	442,889
TOTAL PROVED PLUS PROBABLE	7,116,773	4,615,277	3,322,552	2,559,468	2,064,737

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

TOTAL PROVED RESERVES	REVENUE ($000s)	ROYALTIES ($000s)	OPERATING COSTS ($000s)	DEVELOPMENT COSTS ($000s)	WELL ABANDONMENT COSTS ($000s)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
Canada	8,483,141	1,516,145	2,858,885	668,637	49,041	3,390,433	522,306	2,868,127
United States	3,612,499	1,024,659	622,753	645,567	-	1,319,519	516,764	802,756
Total	12,095,640	2,540,804	3,481,639	1,314,204	49,041	4,709,952	1,039,070	3,670,882
TOTAL PROVED PLUS PROBABLE RESERVES								
Canada	19,625,695	3,621,847	7,042,137	1,549,183	72,142	7,340,385	1,513,529	5,826,856
United States	5,614,096	1,582,422	1,157,180	717,602	-	2,156,892	866,975	1,289,917
Total	25,239,791	5,204,269	8,199,317	2,266,786	72,142	9,497,278	2,380,505	7,116,773

FUTURE NET REVENUE BY PRODUCTION GROUP
AS OF DECEMBER 31, 2013
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) ($000s)	UNIT VALUE ($/boe) (1)
CANADA			
Proved	Heavy Oil (including solution gas and other by-products)	1,664,442	25.29
	Bitumen (including solution gas and other by-products)	324,769	18.95
	Light and Medium Crude Oil (including solution gas and other by-products)	159,104	27.39
	Natural Gas (including by-products but excluding natural gas from oil wells)	123,455	12.24
	Total Canada	2,271,770	
Proved plus Probable	Heavy Oil (including solution gas and other by-products)	2,401,416	23.97
	Bitumen (including solution gas and other by-products)	753,259	9.05
	Light and Medium Crude Oil (including solution gas and other by-products)	212,526	24.00
	Natural Gas (including by-products but excluding natural gas from oil wells)	225,671	11.49
	Total Canada	3,592,872	
UNITED STATES			
Proved	Heavy Oil (including solution gas and other by-products)	-	-
	Bitumen (including solution gas and other by-products)	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	537,424	18.16
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total United States	537,424	
Proved plus Probable	Heavy Oil (including solution gas and other by-products)	-	-
	Bitumen (including solution gas and other by-products)	-	-
	Light and Medium Crude Oil (including solution gas and other by-products)	716,907	16.77
	Natural Gas (including by-products but excluding natural gas from oil wells)	-	-
	Total United States	716,907	
TOTAL			
Proved	Heavy Oil (including solution gas and other by-products)	1,664,442	25.29
	Bitumen (including solution gas and other by-products)	324,769	18.95
	Light and Medium Crude Oil (including solution gas and other by-products)	696,528	19.67
	Natural Gas (including by-products but excluding natural gas from oil wells)	123,455	12.24
	Total	2,809,194	
Proved plus Probable	Heavy Oil (including solution gas and other by-products)	2,401,416	23.97
	Bitumen (including solution gas and other by-products)	753,259	9.05
	Light and Medium Crude Oil (including solution gas and other by-products)	929,433	18.01
	Natural Gas (including by-products but excluding natural gas from oil wells)	225,671	11.49
	Total	4,309,779	

Note:

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

Definitions and Notes to Reserves Data Tables

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

1. "**Gross**" means:

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

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

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

2. "**Net**" means:

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

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

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

3. Definitions used for reserves categories are as follows:

   Reserves Categories

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

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

   (b) the use of established technology; and

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

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

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

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

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

Development and Production Status

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

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

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

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

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

Levels of Certainty for Reported Reserves

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

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

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

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

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

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

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

These are prices and costs that are:

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

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

10. Numbers in the tables may not add due to rounding.

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

Pricing Assumptions

The forecast cost and price assumptions include increases in actual wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, heavy oil, natural gas and natural gas liquids benchmark reference pricing, as at December 31, 2013, inflation and exchange rates utilized in the Sproule Report were as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS AS AT DECEMBER 31, 2013[(1)]

	Oil			Natural Gas			
	WTI Cushing Oklahoma[(2)] ($US/bbl)	**Edmonton Par Price 40° API[(3)] ($Cdn/bbl)**	**Western Canadian Select 20.5° API[(4)] ($Cdn/bbl)**	**AECO-C[(5)] ($Cdn/MMbtu)**	**Henry Hub[(6)] ($US/MMbtu)**	**Inflation Rate[(7)] %/year**	**Exchange Rate[(8)] ($US/$Cdn)**
Historical							
2009	61.63	66.20	58.66	4.19	4.01	2.0	0.880
2010	79.43	77.80	67.21	4.16	4.39	1.2	0.971
2011	95.00	95.16	77.09	3.72	4.04	1.6	1.012
2012	94.19	86.57	73.08	2.43	2.79	1.3	1.001
2013	97.98	93.24	74.20	3.13	3.68	0.8	0.971
Forecast							
2014	94.65	92.64	77.81	4.00	4.17	1.5	0.940
2015	88.37	89.31	75.02	3.99	4.15	1.5	0.940
2016	84.25	89.63	75.29	4.00	4.17	1.5	0.940
2017	95.52	101.62	85.36	4.93	5.04	1.5	0.940
2018	96.96	103.14	86.64	5.01	5.12	1.5	0.940
Thereafter				Escalation Rate of 1.5%			

Notes:
(1) Each price from the Sproule forecast was adjusted for quality differentials and transportation costs applicable to the specific product and evaluation area.
(2) Price used in the preparation of light crude oil reserves in the United States.
(3) Price used in the preparation of light and medium crude oil and natural gas liquids reserves in Canada.
(4) Price used in the preparation of heavy oil and bitumen reserves in Canada.
(5) Price used in the preparation of natural gas reserves in Canada.
(6) Price used in the preparation of natural gas reserves in the United States.
(7) Inflation rates for forecasting prices and costs.
(8) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average prices realized by us for the year ended December 31, 2013, excluding hedging activities, were $64.17/bbl for heavy oil, $79.61/bbl for light oil and NGL and $3.32/Mcf for natural gas.

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

	HEAVY OIL			BITUMEN		
CANADA	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**
December 31, 2012	79,843	42,021	121,863	19,476	82,085	101,562
Extensions and Infills	19,212	5,865	25,078	560	240	800
Improved Recovery	243	888	1,131	-	-	-
Technical Revisions	(2,535)	(6,609)	(9,145)	56	233	289
Discoveries	10	6	17	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	581	473	1,053	132	6	138
Production	(14,451)	-	(14,451)	(903)	-	(903)
December 31, 2013	82,903	42,644	125,547	19,322	85,564	101,886

	LIGHT AND MEDIUM OIL			NATURAL GAS		
CANADA	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (MMcf)**	**Probable (MMcf)**	**Proved Plus Probable (MMcf)**
December 31, 2012	7,891	4,324	12,215	68,665	33,055	101,720
Extensions and Infills	787	159	945	5,882	33,156	39,038
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(732)	(759)	(1,491)	11,223	(6,894)	4,329
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(1,156)	(379)	(1,535)	(22)	(4)	(26)
Economic Factors	78	78	157	(2,224)	1,210	(1,014)
Production	(1,160)	-	(1,160)	(15,208)	-	(15,208)
December 31, 2013	5,707	3,424	9,131	68,316	60,523	128,839

	NATURAL GAS LIQUIDS			OIL EQUIVALENT		
CANADA	**Proved (Mbbl)**	**Probable (Mbbl)**	**Proved Plus Probable (Mbbl)**	**Proved (Mboe)**	**Probable (Mboe)**	**Proved Plus Probable (Mboe)**
December 31, 2012	2,808	1,688	4,495	121,461	135,627	257,089
Extensions and Infills	262	1,739	2001	21,801	13,529	35,331
Improved Recovery	-	-	-	243	888	1,131
Technical Revisions	728	(23)	705	(613)	(8,307)	(8,920)
Discoveries	-	-	-	10	6	17
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	(1,160)	(379)	(1,540)
Economic Factors	(77)	66	(11)	344	824	1,168
Production	(648)	-	(648)	(19,696)	-	(19,696)
December 31, 2013	3,073	3,469	6,542	122,390	142,188	264,578

UNITED STATES	LIGHT AND MEDIUM OIL Proved (Mbbl)	LIGHT AND MEDIUM OIL Probable (Mbbl)	LIGHT AND MEDIUM OIL Proved Plus Probable (Mbbl)	NATURAL GAS Proved (MMcf)	NATURAL GAS Probable (MMcf)	NATURAL GAS Proved Plus Probable (MMcf)
December 31, 2012	17,229	9,755	26,984	10,644	6,202	16,846
Extensions and Infills	15,727	5,916	21,644	21,862	8,227	30,089
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(1,672)	(2,425)	(4,097)	8,827	3,814	12,641
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	101	95	195	134	130	264
Production	(1,142)	-	(1,142)	(118)	-	(118)
December 31, 2013	30,242	13,341	43,583	41,349	18,373	59,722

UNITED STATES	NATURAL GAS LIQUIDS Proved (Mbbl)	NATURAL GAS LIQUIDS Probable (Mbbl)	NATURAL GAS LIQUIDS Proved Plus Probable (Mbbl)	OIL EQUIVALENT Proved (Mboe)	OIL EQUIVALENT Probable (Mboe)	OIL EQUIVALENT Proved Plus Probable (Mboe)
December 31, 2012	2,980	1,737	4,717	21,983	12,525	34,508
Extensions and Infills	-	-	-	19,371	7,287	26,658
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(2,962)	(1,737)	(4,698)	(3,162)	(3,526)	(6,688)
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	123	116	239
Production	(19)	-	(19)	(1,181)	-	(1,181)
December 31, 2013	-	-	-	37,134	16,403	53,537

TOTAL	HEAVY OIL Proved (Mbbl)	HEAVY OIL Probable (Mbbl)	HEAVY OIL Proved Plus Probable (Mbbl)	BITUMEN Proved (Mbbl)	BITUMEN Probable (Mbbl)	BITUMEN Proved Plus Probable (Mbbl)
December 31, 2012	79,843	42,021	121,863	19,476	82,085	101,562
Extensions and Infills	19,212	5,865	25,078	560	240	800
Improved Recovery	243	888	1,131	-	-	-
Technical Revisions	(2,535)	(6,609)	(9,145)	56	233	289
Discoveries	10	6	17	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	581	473	1,053	132	6	138
Production	(14,451)	-	(14,451)	(903)	-	(903)
December 31, 2013	82,903	42,644	125,547	19,322	82,564	101,886

TOTAL	LIGHT AND MEDIUM OIL Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	NATURAL GAS Proved (MMcf)	Probable (MMcf)	Proved Plus Probable (MMcf)
December 31, 2012	25,119	14,079	39,199	79,308	39,257	118,565
Extensions and Infills	16,514	6,075	22,589	27,745	41,382	69,127
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(2,404)	(3,184)	(5,588)	20,051	(3,080)	16,971
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	(1,156)	(378)	(1,535)	(22)	(4)	(26)
Economic Factors	179	173	352	(2,091)	1,341	(750)
Production	(2,303)	-	(2,303)	(15,326)	-	(15,326)
December 31, 2013	35,949	16,765	52,714	109,665	78,895	188,561

TOTAL	NATURAL GAS LIQUIDS Proved (Mbbl)	Probable (Mbbl)	Proved Plus Probable (Mbbl)	OIL EQUIVALENT Proved (Mboe)	Probable (Mboe)	Proved Plus Probable (Mboe)
December 31, 2012	5,788	3,424	9,212	143,444	148,152	291,597
Extensions and Infills	262	1,739	2,001	41,172	20,817	61,989
Improved Recovery	-	-	-	243	888	1,131
Technical Revisions	(2,234)	(1,760)	(3,994)	(3,776)	(11,833)	(15,609)
Discoveries	-	-	-	10	6	17
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	(1,160)	(379)	(1,540)
Economic Factors	(77)	66	(11)	466	941	1,407
Production	(666)	-	(666)	(20,877)	-	(20,877)
December 31, 2013	3,073	3,469	6,542	159,524	158,592	318,115

Additional Information Relating to Reserves Data

Undeveloped Reserves

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

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

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

Proved Undeveloped Reserves

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

	Heavy Oil Gross (Mbbl)		**Bitumen Gross (Mbbl)**		**Light and Medium Oil Gross (Mbbl)**	
Year	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**
Prior	70,360	236,441	13,828	21,998	13,196	33,504
2011	6,887	40,502	2,839	13,496	6,839	18,999
2012	4,382	32,577	1,897	14,044	6,647	15,736
2013	4,203	32,433	490	8,409	15,083	25,792

	Natural Gas Liquids Gross (Mbbl)		**Natural Gas Gross (MMcf)**	
Year	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**
Prior	1,188	3,127	34,339	98,374
2011	3,594	3,811	17,061	28,111
2012	1,612	3,316	12,234	25,639
2013	236	965	25,329	51,757

Sproule assigned proved undeveloped reserves to a total of 912 well locations in which Baytex owns a working interest. Each of these locations with a proved undeveloped reserves attribution also has a probable undeveloped assignment.

Of these 912 locations with proved and probable undeveloped reserves, 308 are located in our Williston Basin property in Divide County, North Dakota. These locations will be developed over the next five years. There are 70 locations in our Peace River heavy oil properties. These locations, which will be drilled over the next two years, will produce heavy oil by primary recovery. Located in our Peace River in-situ thermal recovery project are eight locations which will be drilled over the next five years. Located in our heavy oil properties in Saskatchewan and northeast Alberta are 490 locations. We expect to drill these locations over the next ten years, with nearly 84% being drilled within five years. There are 36 locations in our light oil properties, which are scheduled to be developed over the next six years.

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

Probable Undeveloped Reserves

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

	Heavy Oil Gross (Mbbl)		**Bitumen Gross (Mbbl)**		**Light and Medium Oil Gross (Mbbl)**	
Year	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**
Prior	43,068	123,547	24,779	40,881	19,832	32,048
2011	9,548	26,912	3,424	24,432	5,270	11,435
2012	9,402	24,453	52,919	77,818	6,181	10,414
2013	4,292	24,695	210	73,404	6,956	13,406

	Natural Gas Liquids Gross (Mbbl)		**Natural Gas Gross (MMcf)**	
Year	**First Attributed**	**Booked at Year End**	**First Attributed**	**Booked at Year End**
Prior	1,496	2,644	37,773	79,370
2011	1,912	2,116	8,666	16,794
2012	1,112	2,468	7,912	19,055
2013	1,766	2,836	43,070	61,470

In addition to those locations with proved undeveloped reserves, Sproule assigned reserves to a total of 286 well locations with probable undeveloped reserves only. None of these 286 locations have any proved undeveloped reserves assigned to them.

Of these 286 locations with probable undeveloped reserves only, 53 are located in our Williston Basin property in Divide County, North Dakota. These locations will be developed over the next five years. There are 26 locations in our Peace River heavy oil properties. These locations, which will be drilled over the next three years, will produce heavy oil by primary recovery. Located in our Peace River in-situ thermal recovery project are 20 locations. These locations will be drilled over the next seven years. There are 23 well pairs located in our Gemini SAGD project. These well pairs will be drilled over the next 23 years. The SAGD recovery process at Gemini requires that we drill pairs of wells, one above the other, separated by approximately 5 metres. Because the process requires a pair of wells for the production of bitumen, we count a well pair as a single well. The additional 23 well pairs would completely develop our Gemini SAGD project. Because steam generation is such a large proportion of the operating costs at Gemini, drilling and steaming of wells is scheduled over the next 23 years to make the most efficient use of our steam generating and oil treating facilities. If, after viewing the results of operations at Gemini, we judge it prudent to accelerate drilling and development, which will require additional facilities, we will do so. There are 132 locations in our heavy oil properties in Saskatchewan and northeast Alberta. We expect to drill these locations over the next six years. Located in our light oil properties are 32 locations which will be developed over the next six years.

The table entitled "Probable Undeveloped Reserves" shows the probable undeveloped reserves for all of our locations, including the 912 locations with both a proved and probable undeveloped assignment, and those 286 locations with a probable undeveloped assignment only.

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

Significant Factors or Uncertainties

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

Future Development Costs

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

FUTURE DEVELOPMENT COSTS
AS OF DECEMBER 31, 2013
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**
2014	202,104	323,985	60,071	60,071	262,175	384,056
2015	268,242	434,578	93,971	93,971	362,214	528,549
2016	42,496	268,686	145,975	145,975	188,471	414,661
2017	67,164	183,481	239,140	239,140	306,304	422,621
2018	20,800	68,501	106,409	178,444	127,209	246,945
Remaining	67,831	269,952	-	-	67,831	269,952
Total (undiscounted)	668,637	1,549,183	645,567	717,602	1,314,204	2,266,786

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

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

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

Contingent Resources

We commissioned Sproule to conduct an assessment of contingent resources effective December 31, 2013 on two of our oil resource plays: the Bluesky in the Peace River area of Alberta and the Bakken/Three Forks in North Dakota. We did not request Sproule to prepare an update of the estimate of contingent resources in the Lower Cretaceous Mannville Group for the Gemini SAGD project as no developments had occurred that would have caused a change in the estimate made effective December 31, 2012. We also commissioned McDaniel & Associates Consultants Ltd. ("**McDaniel**") to conduct an assessment of contingent resources effective December 31, 2013 on the Lower Cretaceous Mannville Group in northeast Alberta.

Contingent resources represents the quantity of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. The outstanding contingencies applicable to our disclosed contingent resources do not include economic contingencies. Economic contingent resources are those resources that are currently economically recoverable based on specific forecasts of commodity prices and costs. The assigned contingent resources are categorized as economically recoverable based on economics completed at year-end 2012.

For the total of these four plays, Sproule and McDaniel's estimate of contingent resources ranges from 612 million barrels of oil equivalent and bitumen in the "low estimate" (C1) to 1,181 million barrels of oil equivalent and bitumen in the "high estimate" (C3), with a "best estimate" (C2) of 798 million barrels of oil equivalent and bitumen. Contingent resources are in addition to currently booked reserves.

The best estimate contingent resources of 798 million barrels of oil equivalent and bitumen are largely unchanged from year-end 2012. The best estimate contingent resources for Bakken/Three Forks of 34 million barrels of oil equivalent represents a 26% increase over year-end 2012, and is largely attributable to reduced well spacing. Notable changes to our Bakken/Three Forks contingent resources assessment include land adjustments, transfer of reserves to resources and the conversion of resources to reserves during the year.

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

SUMMARY OF ECONOMIC CONTINGENT RESOURCES(1)

		Economic Contingent Resources (gross)(2)(4)(5)		
(millions of barrels of oil equivalent and bitumen)(3)	**Effective Date**	**Low(6)**	**Best(7)**	**High(8)**
Peace River, Alberta	December 31, 2013	450	553	796
Northeast Alberta	December 31, 2013	66	125	196
Gemini SAGD Project – Cold Lake, Alberta	December 31, 2012	78	87	127
Bakken/Three Forks – North Dakota, USA	December 31, 2013	19	34	63
Total		612	798	1,181

Notes:

(1) Contingent resources are defined in the COGE Handbook as "those quantities of petroleum estimated to be potentially recoverable from known accumulations using established technology or technology under development, but which do not currently qualify as reserves or commercially recoverable due to one or more contingencies. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets."

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

(3) Under NI 51-101, naturally occurring hydrocarbons with a viscosity greater than 10,000 centipoise are classed as bitumen. All of the contingent resources at Peace River and the Gemini SAGD project that will be recovered by thermal processes has a viscosity greater than this value; therefore, this component of the contingent resources is classified as bitumen under NI 51-101.

(4) Sproule and McDaniel prepared the estimates of contingent resources shown for each property using deterministic principles and methods. Probabilistic aggregation of the low and high property estimates shown in the table might produce different total volumes than the arithmetic sums shown in the table. The total volumes presented in the table are arithmetic sums of multiple estimates of contingent resources, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should give attention to the estimates of individual classes of contingent resources and appreciate the differing probabilities of recovery associated with each class as explained herein.

(5) Gross means the company's working interest share in the contingent resources before deducting royalties.

(6) Low estimate (C1) is considered to be a conservative estimate of the quantity of resources that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. Those resources in the low estimate have the highest degree of certainty - a 90% confidence level - that the actual quantities recovered will equal or exceed the estimate.
(7) Best estimate (C2) is considered to be the best estimate of the quantity of resources that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. Those resources in the best estimate have a 50% confidence level that the actual quantities recovered will equal or exceed the estimate.
(8) High estimate (C3) is considered to be an optimistic estimate of the quantity of resources that will actually be recovered. It is unlikely that the actual remaining quantities of resources recovered will equal or exceed the high estimate. Those resources in the high estimate have a lower degree of certainty - a 10% confidence level - that the actual quantities recovered will equal or exceed the estimate.

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

Other Oil and Gas Information

Oil and Natural Gas Properties

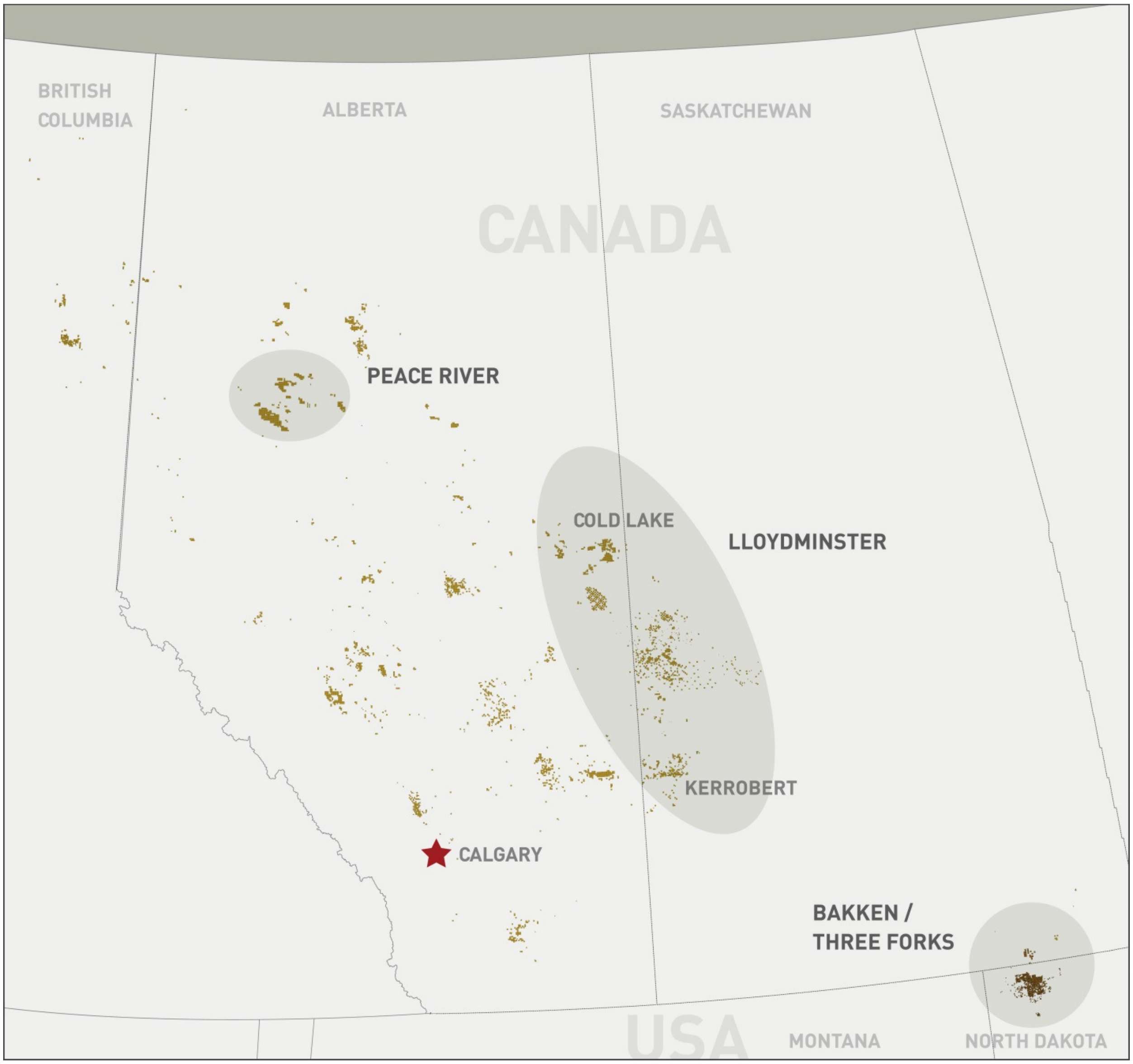
The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2013. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2013. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production for the year ended December 31, 2013, except where otherwise indicated.

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

We will endeavour to continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River oil sands area within the Alberta/B.C. Business Unit and our historical area of emphasis around Lloydminster within the Saskatchewan Business Unit.

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

Baytex Energy Corp. – Principal Properties



Saskatchewan Business Unit

The Saskatchewan Business Unit accounts for more than 30% of current production. The Saskatchewan 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 100 bbl/d of crude oil with gravities ranging from 10 to 18 degrees API. Once produced, the oil is delivered to markets in Canada and the United States via pipelines, tanker trucks or railways. Heavy crude is usually blended with light-hydrocarbon diluents prior to being introduced into a sales pipeline. The heavy crude Baytex delivers to rail for transport is not diluted. The blended (pipeline) and non-blended (rail) crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluents.

In 2013, production in the Saskatchewan Business Unit averaged approximately 19,748 boe/d, which was comprised of 19,091 bbl/d of heavy oil, 10 bbl/d of light oil and 3,892 Mcf/d of natural gas. During 2013, Baytex drilled 156 (116.5 net) wells in the Saskatchewan Business Unit resulting in 146 (106.5 net) oil wells, eight (8 net) stratigraphic and service wells, and two (2 net) dry and abandoned wells, for a success rate of 99% (99% net). Our net undeveloped lands in the Saskatchewan Business Unit totalled approximately 257,802 acres at year-end 2013.

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

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

<u>Ardmore/Cold Lake/Sugden/Angling Lake, Alberta</u>: The Ardmore and Cold Lake assets were acquired in 2002 and 2001, respectively, and have been developed extensively for primary production in the General Petroleum, Sparky, McLaren and Colony formations. Average production during 2013 was approximately 1,634 bbl/d of heavy oil and 595 Mcf/d of natural gas (1,733 boe/d). Baytex drilled 11 (10.2 net) vertical and three (2.9 net) horizontal oil wells in these areas in 2013. Baytex anticipates drilling approximately eight vertical and 17 horizontal oil wells in these areas in 2014.

On October 3, 2012, Baytex acquired a 100% working interest in 46 sections of undeveloped oil sands leases in the Angling Lake (Cold Lake) area of northern Alberta for $120 million. The lands are proximal to our existing Cold Lake heavy oil assets and are prospective for both cold and thermal development. Regulatory approval has been obtained for the construction and operation on approximately 2.5 sections of the acquired lands of a two-stage bitumen recovery scheme using SAGD, which we refer to as the Gemini SAGD project. The first stage, which is a single SAGD well pair pilot, was completed on budget (facility cost - $22 million) and steam circulation into the injector and producer began on January 24, 2014. The producing well is expected to be put on production in Q2/2014, and the pilot will be operated for about three years. Engineering and design is advancing for the second phase, which has received regulatory approval from the Alberta Energy Regulator for 10,000 bbl/d. Five stratigraphic wells were successfully drilled in Q4/2013, in a separate structure to the main reservoir, which may support subsequent thermal expansion beyond the initial development. The purpose of the stratigraphic test wells is to improve delineation of our land base and guide development well trajectories. At year-end 2013, Baytex had 101,784 net undeveloped acres in this area.

<u>Carruthers, Saskatchewan</u>: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. Two (2.0 net) vertical wells and 14 (13.5 net) horizontal wells (including five multi-laterals) were drilled in 2013 which, in combination with relatively low production declines due to strong performance of the ongoing waterfloods, led to a year-over-year production increase. The waterflood was expanded in 2009, 2010 and 2012 with further expansion planned for 2014. We plan to drill 20 horizontal wells (including six multi-laterals) in the Carruthers area in 2014. Average production in 2013 was approximately 2,645 bbl/d of heavy oil and 284 Mcf/d of natural gas (2,692 boe/d). At year-end 2013, Baytex had 8,926 net undeveloped acres in this area.

<u>Celtic, Saskatchewan</u>: This property was acquired by Baytex in 2005. Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base with multiple prospective horizons within the Mannville Group. As a result, the Celtic property provides a multi-year inventory of drilling locations and re-completion opportunities. Baytex drilled 31 (30.7 net) oil wells in the area in 2013 and plans to drill 22 oil wells in this area in 2014. Average production in 2013 was approximately 3,480 bbl/d of heavy oil and 564 Mcf/d of natural gas (3,574 boe/d). At year-end 2013, Baytex had 10,836 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. At year-end 2013, Baytex had 9,097 net undeveloped acres in this area.

At our Kerrobert SAGD project, we drilled a new thermal infill well in 2013, commencing production in Q2/2013 at an average 30-day peak production rate of approximately 670 bbl/d. In addition, one new SAGD well pair commenced production in Q3/2013 at an average 30-day peak production rate of approximately 985 bbl/d. The total cost of the infill and SAGD well pair, including the cost of tie-ins, was $6.97 million. We project that through the remaining life of this project, we can drill up to eight additional well pairs and three additional infill wells with incremental costs of approximately $4.5 million per well pair and $2.0 million per infill well. Baytex plans to drill two thermal infill oil wells in this area in 2014. Average production from the Kerrobert SAGD project in 2013 was approximately 2,007 bbl/d of heavy oil.

Production from the cold primary assets averaged approximately 1,259 bbl/d of heavy oil, 10 bbl/d of light oil, and 1,029 Mcf/d of natural gas (1,441 boe/d). Baytex drilled four (4.0 net) cold primary oil wells in this area in 2013. Baytex plans to drill five cold primary oil wells in this area in 2014.

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

Lindbergh, Alberta: Lindbergh is a primarily non-operated heavy oil property that was purchased in 2007. Baytex has a 21.25% working interest in this property. Average production in this area during 2013 was approximately 857 bbl/d of heavy oil and 69 Mcf/d of natural gas (869 boe/d). Like Tangleflags and Celtic, Lindbergh is a multi-zone property that is expected to provide future development projects for many years. Thus far, economic production has been obtained from the Dina, Cummings, General Petroleum, Sparky and Colony formations. In 2013, 46 (9.8 net) wells were drilled in this area. At year-end 2013, Baytex had 776 net undeveloped acres in this area.

Marsden/Epping/Macklin/Buzzard, Saskatchewan: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18 degrees API. Initial per well production rates are typically 30 to 70 bbl/d. Primary recovery factors can be as high as 30% of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average production in this area during 2013 was approximately 1,238 bbl/d of oil and 365 Mcf/d of natural gas (1,299 boe/d). Eight (8.0 net) wells were drilled in this area in 2013. Baytex plans to drill three wells in this area in 2014. At year-end 2013, Baytex had 21,356 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 2013, Baytex drilled three (3.0 net) horizontal oil wells in the Lloydminster formation. In 2014, we plan to drill approximately four horizontal oil wells and re-complete up to 20 wells. A waterflood pilot of the Lloydminster formation commenced in 2013 and a larger commercial waterflood project is planned for 2014. Average production during 2013 was approximately 1,998 bbl/d of heavy oil and 199 Mcf/d of natural gas (2,031 boe/d). At year-end 2013, Baytex had 3,462 net undeveloped acres in this area.

Alberta/B.C. Business Unit

The Alberta/B.C. Business Unit produces light and heavy gravity crude oil, natural gas and natural gas liquids from various fields in northern, southeast and central Alberta and northeast British Columbia and accounts for approximately 60% of current production. During 2013, production from this business unit averaged 34,213 boe/d, which was comprised of 22,974 bbl/d of heavy oil, 4,943 bbl/d of light oil and NGL and 37.8 MMcf/d of natural gas.

During 2013, Baytex drilled 104 (101 net) wells in the Alberta/B.C. Business Unit resulting in 70 (67 net) oil wells, three (3 net) natural gas wells and 31 (31 net) stratigraphic/service wells, for a success rate of 100%. Our net undeveloped lands in this business unit totalled approximately 454,443 acres at year-end 2013.

Listed below are brief descriptions of the principal properties within the Alberta/B.C. Business Unit:

Bon Accord, Alberta: Baytex acquired its initial position in this multi-zone property in 1997 and has further expanded its presence through Crown land purchases. Production is obtained from the Belly River, Viking and Mannville formations. During 2013, production from this area averaged approximately 931 bbl/d of light oil and 1,337 Mcf/d of natural gas (1,154 boe/d). Natural gas is processed at two Baytex-operated plants and oil is treated at three Baytex-operated batteries. In this area, Baytex drilled eight (5.4 net) horizontal Viking oil wells in 2013. At year-end 2013, Baytex had 8,552 net undeveloped acres in this area.

Peace River, Alberta: Baytex holds a total of 306 net sections of oil sands leases in the Peace River area, which includes the legacy Seal area and the Reno area which was acquired in February 2011. During 2013, production from the Peace River area averaged approximately 22,974 bbl/d of heavy oil (including thermally produced volumes described below) and 1,164 Mcf/d of natural gas (23,168 boe/d). In 2013, Baytex drilled 41 (41 net) cold horizontal production wells, 15 (15 net) cyclic steam stimulation ("**CSS**") wells, 24 (24 net) stratigraphic test wells and seven (7 net) service wells in the Peace River area. The purpose of the stratigraphic test wells is to improve delineation of our land base and guide development well trajectories. In 2014, Baytex plans to drill 36 (36 net) cold multi-lateral horizontal wells and 28 (28 net) stratigraphic test wells. At year-end 2013, Baytex had 147,079 net undeveloped acres in this area.

In certain parts of the Peace River land base, heavy oil can be produced using multi-lateral horizontal wells at initial production rates of 300 to 700 bbl/d per well without employing more cost-intensive secondary and tertiary recovery methods. Reservoir analysis of the Peace River property has indicated that waterflood and polymer flood recovery methods have the potential to increase economic oil reserves beyond what is achievable with cold primary recovery in some areas. Baytex has also demonstrated that CSS can be successfully applied to areas of the Peace River oil sands.

Baytex has continued to progress its thermal operations in the Cliffdale area. The original 10-well CSS module at Pad 1 produced 173,970 barrels of oil in 2013 (increased from 128,130 barrels in 2012) with an average steam-oil-ratio of 2.4 barrels of steam per barrel of oil. The original CSS pilot well received its fifth steam cycle with a total of 71,580 barrels of steam (cold water equivalent) injected, an increase of approximately 115% over the previous cycle. The subsequent production cycle reached an average 30-day peak production rate of approximately 210 bbl/d. Pad 1 steaming operations were offline for approximately 70 days in 2013 due to maintenance and repairs of the steam generators. Repairs were completed throughout the third and fourth quarters of 2013 and steam operations were restarted, generating average production for the fourth quarter of 2013 of 410 bbl/d. Pad 1 production and cumulative steam-oil ratio performance continue to track our predictions when incorporating downtime in the reservoir model.

Regulatory approval was received in the first quarter 2013 for Pad 2, a 15-well CSS module adjacent to Pad 1. Thermal facility construction began early in the second quarter of 2013 with first steam injection planned for late in the second quarter of 2014. This facility will be capable of handling 2,150 barrels per day of oil production and generating 4,720 barrels of steam (cold water equivalent) per day. The 15 CSS wells were drilled successfully throughout 2013 and are currently producing as planned under primary conditions to create the initial voidage required for the CSS process.

An application was submitted in the fourth quarter of 2013 to the Alberta Energy Regulator and Alberta Environment and Sustainable Resource Development for an expansion of the thermal program to the east. Pads 3 and 4 would be constructed adjacent to the existing two pads, each having 15 CSS wells for a total of 55 CSS wells at Cliffdale. A central processing facility has been proposed at Pad 3 capable of handling 4,400 barrels per day of oil production and generating 9,400 barrels of steam (cold water equivalent) per day. The central processing facility will be designed to receive and process emulsion from Pads 3 and 4 as well as recycle produced water from all four pads. Baytex is currently addressing Supplemental Information Requests from the Alberta Energy Regulator, Alberta Environment and Sustainable Resource Development and First Nations.

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 Nisku, Cretaceous and Jurassic age formations, including the Cardium, Ellerslie, Glauconite, Notikewin, Rock Creek and Nordegg. The majority of Baytex's oil production in this area is treated at a Baytex-operated oil battery with the remaining production treated at third party-operated oil batteries. Natural gas production is delivered to a combination of four mid-stream gas processing facilities and three producer-operated gas processing facilities. Baytex owns a working interest in one of the midstream-operated gas processing facilities. Production from this area during 2013 averaged approximately 1,941 bbl/d of light oil and NGL and 19,926 Mcf/d of natural gas (5,262 boe/d). Baytex participated in the drilling of five (5 net) wells in this area in 2013, resulting in two (2 net) oil wells and three (3 net) natural gas wells. Pembina area drilling included two (2 net) operated Cardium horizontal wells which were successfully drilled and completed with multi-stage fracture stimulations. Baytex plans to drill three (3 net) gas wells and two (2 net) oil wells in this area in 2014. At year-end 2013, Baytex had 13,328 net undeveloped acres in this area.

Red Earth Alberta: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Baytex-operated sweet oil batteries. Production from this area during 2013 averaged approximately 474 bbl/d of light oil and NGL and 3 Mcf/d of natural gas (475 boe/d). Baytex plans to drill three (2.7 net) wells in the area in 2014. At year-end 2013, Baytex had 7,889 net undeveloped acres in this area.

Stoddart, British Columbia: This property was acquired by Baytex in 2004. Oil and liquids-rich gas production in this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Baytex-operated batteries and natural gas is compressed at four Baytex-operated sites and sent for further processing at two third party-operated gas plants. Production from this area during 2013 averaged approximately 3,448 Mcf/d of natural gas and 512 bbl/d of oil and NGL (1,087 boe/d). Baytex did not drill any wells in this area in 2013. At year-end 2013, Baytex had 22,817 net undeveloped acres in this area.

United States Business Unit

Baytex acquired a significant land position in the Williston basin in 2008. During 2013, we focused our activities on the light oil resource play located in Divide and Williams Counties of North Dakota. Production is primarily from horizontal wells using multi-stage hydraulic fracturing in the Bakken and Three Forks formations. We own approximately 120,200 (61,400 net) acres of land in North Dakota, of which 39,845 (23,610 net) acres were undeveloped at year-end 2013. In 2013, Baytex participated in the drilling of 20 (8.6 net) Bakken/Three Forks oil wells with a success rate of 100%. In 2014, Baytex plans to drill approximately 15 (9.6 net) horizontal wells. Ultimately, the project has the potential to include over 200 net additional wells with average initial production rates expected to be approximately 345 boe/d per well and average recoveries expected to be approximately 390 Mboe per well, based on drilling two-mile (or 1,280-acre spacing unit) wells. Production from the United States Business Unit in 2013 averaged 3,181 bbl/d and 324 Mcf/d (3,235 boe/d).

In 2012, Baytex entered into an agreement to acquire approximately 72,300 (50,600 net) acres (70% working interest) in the Weston and Niobrara Counties of Wyoming for US$176 per net acre (total initial consideration of US$8.9 million). During 2013, Baytex drilled one of two horizontal earning wells to test the Turner formation, which produces from existing vertical wells in the area and is being developed with horizontal techniques elsewhere in the basin. Baytex will complete its obligations under this agreement by carrying the seller for a 30% working interest in the second of two wells during 2014, estimated to cost approximately US$4 million on a 100% basis. At year-end 2013, Baytex owned the rights to 72,286 (49,060 net) acres in the Weston and Niobrara Counties of Wyoming, of which 71,649 (48,614 net) acres are undeveloped.

Average Production

The following table indicates our average daily production from our principal areas for the year ended December 31, 2013.

	Light Oil and NGL (bbl/d)	Heavy Oil (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Saskatchewan Business Unit				
Ardmore	-	1,129	178	1,159
Angling Lake	-	39	-	39
Carruthers	-	2,645	284	2,692
Celtic	-	3,480	564	3,574
Cold Lake	-	205	-	205
Forest Bank	-	388	293	437
Golden Lake	-	813	-	813
Greenstreet	-	123	435	195
Hoosier	-	849	1,022	1,019
Kerrobert	10	2,417	7	2,428
Lindbergh	-	857	69	869
Maidstone	-	590	-	590
Marsden / Epping / Macklin / Buzzard	-	1,238	365	1,299
Neilburg	-	695	-	695
Poundmaker / Freemont	-	1,322	59	1,332
Sugden	-	261	417	330
Tangleflags	-	1,998	199	2,031
Remaining properties	-	41	-	41
Total Saskatchewan Business Unit	10	19,090	3,892	19,748
Alberta/B.C. Business Unit				
Bon Accord	931	-	1,337	1,154
Ferrier	370	-	1,883	684
Darwin / Nina / Goodfish / Lafond	2	-	2,563	429
Leahurst	11	-	1,753	303
Peace River	-	22,974	1,164	23,168
Pembina	1,941	-	19,926	5,262
Red Earth	474	-	3	475
Richdale / Sedalia	24	-	3,089	539
Stoddart	512	-	3,448	1,087
Tableland	246	-	-	246
Turin	283	-	577	379
Remaining Properties	149	-	2,030	487
Total Alberta/B.C. Business Unit	4,943	22,974	37,773	34,213
United States Business Unit				
Williston Basin	3,148	-	324	3,202
Powder River Basin	33	-	-	33
Remaining properties	-	-	-	-
Total United States Business Unit	3,181	-	324	3,235
Grand Total	8,134	42,064	41,989	57,196

Costs Incurred

The following table summarizes the property acquisition, exploration and development costs by country for the year ended December 31, 2013:

($000s)	Canada	United States	Total
Property acquisition costs [1]			
Proved properties	3,604	90	3,694
Unproved properties	707	2,353	3,060
Property disposition	(45,003)	(833)	(45,836)
Total Property acquisition costs, net	(40,692)	1,610	(39,082)
Development Costs [2]	467,191	75,176	542,367
Exploration Costs [3]	7,110	1,423	8,533
Total	433,609	78,209	511,818

Notes:
(1) Property acquisition costs include the acquisition of a company that held assets in Alberta.
(2) Development and facilities expenditures.
(3) Cost of geological and geophysical capital expenditures and drilling costs for 2013 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, 2013.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	922	619.3	1,038	597.7	462	344.1	493	378.1
British Columbia	44	43.7	34	33.2	38	34.8	15	13.8
Saskatchewan	1,150	1,090.9	1,363	1,259.9	40	35.9	125	111.4
North Dakota	106	42.7	1	1.0	-	-	-	-
Wyoming	5	2.7	5	3.2	-	-	-	-
Total	2,227	1,799.3	2,441	1,895.0	540	414.8	633	503.3

Undeveloped Land Holdings

The following table sets forth our undeveloped land holdings as at December 31, 2013.

	Undeveloped Acres	
	Gross	Net
Canada		
Alberta	587,319	512,682
British Columbia	38,239	29,629
Saskatchewan	178,918	169,934
Total Canada	804,476	712,245
United States		
New Mexico	14,313	14,313
North Dakota	39,845	23,610
Wyoming	100,542	63,983
Total United States	154,700	101,906
Grand Total	959,176	814,151

We estimate the value of our net undeveloped land holdings at December 31, 2013 to be approximately $282 million, as compared to $354 million at December 31, 2012. This internal evaluation generally represents the estimated replacement cost of our undeveloped land. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown and State land sales for the properties in the vicinity of our undeveloped land holdings, less an allowance for near-term expiries.

We expect that rights to explore, develop and exploit approximately 89,736 net acres of our undeveloped land holdings may expire on or before December 31, 2014. There are no material drilling commitments associated with the land holdings expiring by December 31, 2014.

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, 2013.

	Exploratory Wells		Development Wells		Total Wells	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Oil	-	-	237	182.8	237	182.8
Natural Gas	-	-	3	3.0	3	3.0
Evaluation	-	-	29	29.0	29	29.0
Service	-	-	10	10.0	10	10.0
Dry	-	-	2	2.0	2	2.0
Total	-	-	281	226.8	281	226.8

Forward Contracts

For details on our contractual commitments to sell natural gas and crude oil which were outstanding at December 31, 2013, see Note 20 to our audited consolidated financial statements for the year ended December 31, 2013.

Tax Horizon

Based on the current tax regime and Baytex's available tax pools and anticipated level of funds from operations and capital spending, Baytex does not expect to pay material amounts of cash income taxes prior to 2015. This estimate is highly sensitive to assumptions regarding commodity prices, production, funds from operations and capital expenditure levels. As at December 31, 2013, Baytex's total Canadian tax pools were estimated to be $1.3 billion, including $381 million for tangibles, $790 million for intangibles and $160 million in non-capital loss carryforwards. In addition, as at December 31, 2013, Baytex's total United States tax pools were estimated to be $145 million, including $19 million for tangibles, $54 million for intangibles, $65 million in net operating losses, and $7 million of Alternative Minimum Tax carryforward.

Additional Information Concerning Abandonment and Reclamation Costs

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

Period	Abandonment and Reclamation Costs Escalated at 2% Undiscounted ($ thousands)	Abandonment and Reclamation Costs Escalated at 2% Discounted at 10% ($ thousands)
Total liability as at December 31, 2013	333,424	44,122
Anticipated to be paid in 2014	2,081	2,003
Anticipated to be paid in 2015	2,271	2,028
Anticipated to be paid in 2016	1,953	1,618

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

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

The number of net wells for which we estimated we will incur reclamation and abandonment costs is 4,625 wells. This estimate includes all producing wells, all non-producing wells, all standing cased wells and all suspended wells. The number of net wells for which Sproule estimated we will incur reclamation and abandonment costs is 940 wells which are all the proved undeveloped and probable undeveloped wells. The latter two well groups had not been drilled as of December 31, 2013. Abandonment and reclamation costs have been estimated over a 50-year period. Facility reclamation costs are scheduled to be incurred two years following the end of the reserve life of its associated producing area. Only well abandonment costs, net of downhole salvage value, were deducted by Sproule in estimating future net revenue in the Sproule Report. The additional liability associated with our existing wells, pipelines and facility reclamation costs, net of salvage, which was estimated to be $333.4 million ($44.1 million discounted at 10 percent), was not deducted in estimating future net revenue.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2014, which is reflected in the estimate of future net revenue disclosed in the forecast price tables contained under "*Description of Our Business and Operations – Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Reserves Data and Oil and Natural Gas Information*".

	Light and Medium Oil (bbl/d)	Heavy Oil (bbl/d)	Natural Gas Liquids (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
CANADA					
Total Proved	2,569	43,758	1,396	33,400	53,290
Total Proved plus Probable	2,735	48,165	1,756	40,594	59,422
UNITED STATES					
Total Proved	3,355	-	-	4,322	4,075
Total Proved plus Probable	3,455	-	-	4,460	4,199
TOTAL					
Total Proved	5,924	43,758	1,396	37,721	57,365
Total Proved plus Probable	6,191	48,165	1,756	45,054	63,621

The only property that accounts for 20% or more of the estimated 2014 production volumes is Peace River (cold primary production). Estimated 2014 production volumes for Peace River (cold primary production) are 22,449 boe/d on a total proved basis and 24,041 boe/d on a total proved plus probable basis. Note: these production volumes do not include production from the adjacent Reno area.

Production History

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

	Three Months Ended				Year Ended
	Dec. 31, 2013	**Sept 30, 2013**	**June 30, 2013**	**Mar. 31, 2013**	**Dec. 31, 2013**
Average Daily Production (1)					
Light Oil and NGL (bbl/d) (2)	8,047	8,366	8,202	7,920	8,134
Heavy Oil (bbl/d)	43,254	44,908	42,510	37,486	42,064
Natural Gas (Mcf/d)	42,018	41,460	45,148	39,305	41,989
Total (boe/d)	58,304	60,184	58,236	51,957	57,196
Average Net Production Prices Received					
Light Oil and NGL($/bbl) (2)	74.73	88.63	77.85	76.72	79.61
Heavy Oil ($/bbl)	61.89	79.29	63.92	53.47	65.24
Natural Gas ($/Mcf)	3.52	2.72	3.59	3.46	3.32
Total ($/boe)	58.75	73.36	60.42	52.89	61.74
Royalties Paid					
Light Oil and NGL($/bbl) (2)	19.34	22.01	20.82	22.42	21.14
Heavy Oil ($/bbl)	12.26	16.30	12.54	8.41	12.57
Natural Gas ($/Mcf)	(0.37)	(0.26)	(0.55)	0.26	(0.24)
Total ($/boe)	11.49	15.04	11.66	9.68	12.07
Operating Expenses (3)(4)					
Light Oil and NGL($/bbl) (2)	16.60	16.17	13.57	13.00	14.86
Heavy Oil ($/bbl)	12.17	12.22	12.74	13.94	12.72
Natural Gas ($/Mcf)	2.15	2.50	2.28	2.52	2.36
Total ($/boe)	12.87	13.09	12.97	13.95	13.20
Transportation Expenses					
Light Oil and NGL($/bbl) (2)	0.45	0.59	0.56	0.35	0.49
Heavy Oil ($/bbl)	5.08	3.87	5.32	5.83	4.98
Natural Gas ($/Mcf)	0.13	0.17	0.17	0.15	0.15
Total ($/boe)	3.94	3.09	4.08	4.38	3.85
Netback Received (5)					
Light Oil and NGL($/bbl) (2)	38.34	49.86	42.91	40.96	43.12
Heavy Oil ($/bbl)	32.38	46.90	33.33	25.28	34.97
Natural Gas ($/Mcf)	1.61	0.31	1.70	0.53	1.05
Total ($/boe)	30.45	42.14	31.71	24.88	32.62
Financial Derivatives gain (loss) ($/boe) (6)	1.03	(2.88)	1.62	1.68	0.29
Netback Received after hedging ($/boe)	31.48	39.26	33.33	25.56	32.91

Notes:
(1) Before deduction of royalties.
(2) Our NGL volumes are not material, and have been grouped with light oil for reporting purposes.
(3) Operating expenses are composed of direct costs incurred to operate both oil and gas wells. A number of assumptions are required to allocate these costs between oil, natural gas and natural gas liquids production.
(4) Operating recoveries associated with operated properties are charged to operating costs and accounted for as a reduction to general and administrative costs.
(5) Netback is calculated by subtracting royalties, operating expenses, transportation expenses and losses/gains on commodity and foreign exchange contracts from revenues.
(6) Financial derivatives reflect realized gains (losses) on commodity-related contracts only and exclude the impact of interest rate swaps.

Marketing Arrangements

Baytex markets its oil and natural gas production with attention to maximizing value and counterparty performance. We maintain a portfolio of sales contracts with a variety of pricing mechanisms, term commitments and customers. We engage a number of reputable counterparties in our bid process to ensure competitiveness, while also managing counterparty credit exposure. In response to market conditions, sales of undiluted bitumen to rail loading facilities continued to expand in 2013, representing a significant position within Baytex's market access portfolio.

Oil and NGL

For the year ended December 31, 2013, the prompt price of West Texas Intermediate crude oil fluctuated between a low of US$85.61/bbl and a high of US$112.24/bbl, with an average price of US$97.97/bbl. The volatile price range seen in 2013 reflected both uneven sentiment over global economic conditions and several periods of geopolitical tension.

The discount for Canadian heavy oil, as measured by the Western Canadian Select ("**WCS**") price differential to WTI, averaged 26% for the year ended December 31, 2013, as compared to a 22% average for the year ended December 31, 2012. WCS price differential volatility remained high in 2013 due to several factors, including export pipeline capacity problems, which at times constrained access to U.S. refineries, continued Canadian heavy oil production growth, which reduced spare export capacity, and periodic planned and unplanned maintenance at refineries using Canadian heavy oil. Concurrence of these factors at times exacerbated the impact on heavy oil pricing, with the monthly WCS price differential exceeding 30% in four months of 2013. However, in periods when these factors were not present, the monthly WCS price differential was tight, averaging 15% or less in three months of 2013.

For 2013, Baytex's heavy oil sales prices averaged $65.24/bbl (net of physical forward sales gains of $1.07/bbl), while light oil and NGL prices averaged $79.61/bbl. In contrast, for 2012 Baytex averaged $59.44/bbl for heavy oil sales (net of physical forward sales gains of $0.84/bbl) and $74.07/bbl for light oil and NGL sales. Baytex's total oil and NGL price in 2013 was $67.57/bbl (net), as compared with $61.74/bbl (net) in 2012.

Natural Gas

For the year ended December 31, 2013, the average AECO natural gas price was $3.13/Mcf, as compared to $2.40/Mcf in the same period of 2012. The increase in the natural gas price was due to colder than normal weather driving up natural gas demand in the fourth quarter of 2013, which resulted in significant U.S. and western Canada storage draws. For 2013, Baytex's average physical natural gas sales price (inclusive of physical forward sales contracts) was $3.32/Mcf, as compared to $2.45/Mcf in 2012.

Environmental Policies

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

DIRECTORS AND OFFICERS

The following table sets forth the name, municipality of residence, age as at December 31, 2013, position held with Baytex and principal occupation of each of the directors and officers of Baytex.

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
James L. Bowzer Calgary, Alberta	53	Director, President and Chief Executive Officer	President and Chief Executive Officer of Baytex
John A. Brussa (3) (4) Calgary, Alberta	56	Director	Vice Chairman of Burnet, Duckworth & Palmer LLP
Raymond T. Chan Calgary, Alberta	58	Director and Executive Chairman	Executive Chairman of Baytex

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
Edward Chwyl (2) (3) (4) Victoria, B.C.	70	Director	Independent Businessman
Naveen Dargan (1) (2) Calgary, Alberta	56	Director	Independent Businessman
R.E.T. (Rusty) Goepel (4) Vancouver, B.C.	71	Director	Senior Vice President of Raymond James Ltd.
Gregory K. Melchin (1) Calgary, Alberta	60	Director	Independent Businessman
Mary Ellen Peters (1) (2) Highland, Michigan	57	Director	Independent Businesswoman
Dale O. Shwed (3) Calgary, Alberta	55	Director	President and Chief Executive Officer of Crew Energy Inc.
Daniel G. Anderson Denver, Colorado	51	Vice President, U.S. Business Unit	President of Baytex USA
Kendall D. Arthur Calgary, Alberta	33	Vice President, Saskatchewan Business Unit	Vice President, Saskatchewan Business Unit of Baytex
W. Derek Aylesworth Calgary, Alberta	51	Chief Financial Officer	Chief Financial Officer of Baytex
Geoffrey J. Darcy Calgary, Alberta	51	Vice President, Marketing	Vice President, Marketing of Baytex
Murray J. Desrosiers Calgary, Alberta	44	Vice President, General Counsel and Corporate Secretary	Vice President, General Counsel and Corporate Secretary of Baytex
Brian G. Ector Calgary, Alberta	45	Vice President, Investor Relations	Vice President, Investor Relations of Baytex
Cameron A. Hercus Calgary, Alberta	44	Vice President, Corporate Development	Vice President, Corporate Development of Baytex
Mark A. Montemurro Calgary, Alberta	53	Vice President, Thermal Projects	Vice President, Thermal Projects of Baytex
Timothy R. Morris Denver, Colorado	57	Vice President, US Business Development	Vice President of Baytex USA
Marty L. Proctor Calgary, Alberta	53	Chief Operating Officer	Chief Operating Officer of Baytex
Richard P. Ramsay Calgary, Alberta	50	Vice President, Alberta/B.C. Business Unit	Vice President, Alberta/B.C. Business Unit of Baytex

Name and Municipality of Residence	Age	Position with Baytex	Principal Occupation
Gregory A. Sawchenko Calgary Alberta	41	Vice President, Land	Vice President, Land of Baytex

Notes:
(1) Member of our Audit Committee.
(2) Member of our Compensation Committee.
(3) Member of our Reserves Committee.
(4) Member of our Nominating and Governance Committee.
(5) Baytex's directors hold office until the next annual general meeting of Shareholders or until each director's successor is appointed or elected pursuant to the *Business Corporations Act* (Alberta).

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

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

John A. Brussa became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since October 8, 1997. He is the Vice Chairman of Burnet, Duckworth & Palmer LLP and focuses on tax law. He was admitted to the Alberta bar in 1982. Mr. Brussa is a director of the following public companies: Argent Energy Ltd. (the administrator of Argent Energy Trust); Crew Energy Inc.; Enseco Energy Services Corp.; Just Energy Group Inc.; Long Run Exploration Ltd.; Penn West Petroleum Ltd.; Pinecrest Energy Inc.; RMP Energy Inc.; Storm Resources Ltd.; TORC Oil & Gas Ltd.; Twin Butte Energy Ltd.; and Yoho Resources Inc. 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 Executive Chairman of Baytex on December 31, 2010 and has held the same position with Baytex Energy since January 1, 2009. He served as the Interim Chief Executive Officer of Baytex and Baytex Energy from May to September 2012. He originally joined Baytex Energy in October 1998 and has held the following positions: Senior Vice President and Chief Financial Officer (October 1998 to August 2003); President and Chief Executive Officer (September 2003 to November 2007); and Chief Executive Officer (November 2007 to December 2008). Mr. Chan has been a director of Baytex Energy since October 1998. Mr. Chan has held senior executive positions in the Canadian oil and gas industry since 1982, including chief financial officer titles at Tarragon Oil and Gas Limited, American Eagle Petroleums Ltd. and Gane Energy Corporation. Mr. Chan holds a Bachelor of Commerce degree and is a Chartered Accountant.

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

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

R.E.T. (Rusty) Goepel became a Director of Baytex on December 31, 2010 and has been a director of Baytex Energy since May 11, 2005. He is currently Senior Vice President for Raymond James Ltd. He commenced his career in investment banking in 1968 and was President and co-founder of Goepel Shields & Partners, which later became Goepel McDermid Ltd. and was acquired by Raymond James Ltd. in 2001. Mr. Goepel is a director of Telus Corporation and Amerigo Resources Ltd. He is past Chairman of the Vancouver 2010 Winter Olympics and The Business Council of British Columbia. He is a recipient of the Queen's Gold and Diamond Jubilee Medals for service to the community, financial industry and business. Mr. Goepel holds a Bachelor of Commerce (Honours) degree from the University of British Columbia.

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

Mary Ellen Peters became a Director of Baytex and Baytex Energy on July 1, 2013. She holds a Bachelor of Science degree (major in finance) and a Master of Business Administration degree. She has also completed executive management programs at Penn State University and Indiana University and the Oxford Energy Seminar. She is a retired businesswoman with over 30 years of experience in the petroleum industry, most notably as Senior Vice President, Transportation and Logistics from 2009-2010 and Senior Vice President, Marketing from 1998-2009 at Marathon Petroleum Company LP. Prior thereto, she held various technical and management positions with Marathon. Peters' previous board experience includes acting as Chairman of the Board of Managers for Louisiana Offshore Oil Port and as a director of Colonial Pipeline Company.

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

Daniel G. Anderson was appointed Vice President, U.S. Business Unit on September 13, 2011. In this role he is also President of Baytex's wholly-owned subsidiary, Baytex Energy USA Ltd., which is based in Denver, Colorado. Mr. Anderson has over 25 years of experience in the upstream and mid-stream energy industry in the U.S. He was formerly Vice President of Rocky Mountain and Mid-Continent Production with Berry Petroleum Company. Mr. Anderson previously held a variety of technical and management positions with Williams, Barrett Resources, Santa Fe Snyder and Conoco. His work has involved both operating and business development activities in the Williston Basin, U.S. Rockies, Mid-Continent and Gulf Coast regions. Mr. Anderson received a Bachelor of Science degree in Petroleum Engineering from the Colorado School of Mines and is a practicing member of the Society of Petroleum Engineers (SPE).

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

W. Derek Aylesworth was appointed Chief Financial Officer of Baytex on October 22, 2010 and has held the same position with Baytex Energy since November 2005. He is responsible for Baytex's capital markets, financial reporting and compliance, financial risk management, tax and treasury functions. Prior to joining Baytex Energy, Mr. Aylesworth held the position of Commercial Manager of the Ecuador Region business unit at EnCana Corporation. Prior thereto, he was the Division Vice President for the International New Ventures Exploration business unit of the same company. Mr. Aylesworth has over 25 years of experience in the Canadian oil and gas industry. Mr. Aylesworth holds a Bachelor of Commerce degree and is a Chartered Accountant with expertise in taxation and has experience as a tax advisor in both the oil and gas industry and public practice in Calgary.

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

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

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

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

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

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

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

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

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.

Ownership of Securities by Management

As at March 3, 2014, the directors and executive officers of Baytex, as a group, beneficially owned, or controlled or directed, directly or indirectly, 1,730,093 Common Shares, representing approximately 1.4 percent of the issued and outstanding Common Shares, 118,000 Subscription Receipts and $80,000 principal amount of 2022 Debentures.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

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

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

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

Conflicts

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

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

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

Composition of the Audit Committee

The members of our Audit Committee are Naveen Dargan, Gregory K. Melchin and Mary Ellen Peters, each of whom is "independent" and "financially literate", with the meaning of National Instrument 52-110 "Audit Committees". The relevant education and experience of each Audit Committee member is outlined below:

Name	Independent	Financially Literate	Relevant Education and Experience
Naveen Dargan	Yes	Yes	Bachelor of Arts (Honours) degree in Mathematics and Economics, Master of Business Administration degree and Chartered Business Valuator designation. Independent businessman since June 2003; prior thereto Senior Managing Director and Head of Energy Investment Banking of Raymond James Ltd.
Gregory K. Melchin	Yes	Yes	Bachelor of Science degree (major in accounting) and a Fellow Chartered Accountant designation from the Institute of Chartered Accountants of Alberta. Also completed the Directors Education Program with the Institute of Corporate Directors. Member of the Legislative Assembly of Alberta from March 1997 to March 2008. Prior to being elected to the Legislative Assembly of Alberta, served in various management positions for 20 years in the Calgary business community.
Mary Ellen Peters	Yes	Yes	Bachelor of Science degree (major in finance) and a Master of Business Administration degree. Also completed the Penn State Executive Leadership Program. Retired businesswoman with over 30 years of experience in the petroleum industry, most notably as Senior Vice President, Transportation and Logistics (2009-2010) and Senior Vice President, Marketing (1998-2009) at Marathon Petroleum Company, LP.

Pre-Approval of Policies and Procedures

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

External Auditor Service Fees

The following table provides information about the fees billed to us and our subsidiaries for professional services rendered by Deloitte LLP, our external auditors, during fiscal 2013 and 2012:

	Aggregate fees billed ($000s)	
	2013	**2012**
Audit Fees	$1,056	$1,031
Audit-Related Fees	-	-
Tax Fees	21	364
All Other Fees	-	-
	$1,077	$1,395

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 2013 and 2012 also include amounts for audit work performed in relation to the requirements of Section 404 of the

Sarbanes-Oxley Act of 2002 relating to internal control over financial reporting and review of prospectuses related to debt issuances.

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

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

DESCRIPTION OF CAPITAL STRUCTURE

Share Capital

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

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

Common Shares

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

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

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

Preferred Shares

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

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

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

Debentures

On February 17, 2011, we issued US$150 million principal amount of 6.75% series B senior unsecured debentures. The 2021 Debentures pay interest semi-annually and mature on February 21, 2021 at which time they are due and payable. The 2021 Debentures are unsecured and therefore, for all practical purposes, are subordinate to the Credit Facilities. After February 17 of each of the following years, the 2021 Debentures are redeemable at our option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the 2021 Debentures) plus accrued and unpaid interest thereon, if any: 2016 at 103.375%; 2017 at 102.250%; 2018 at 101.125%; and 2019 at 100%.

On July 19, 2012, we issued $300 million principal amount of 6.625% series C senior unsecured debentures. The 2022 Debentures pay interest semi-annually and mature on July 19, 2022 at which time they are due and payable. The 2022 Debentures are unsecured and therefore, for all practical purposes, are subordinate to the Credit Facilities. After July 19 of each of the following years, the 2022 Debentures are redeemable at our option, in whole or in part, with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the 2022 Debentures) plus accrued and unpaid interest thereon, if any: 2017 at 103.313%; 2018 at 102.208%; 2019 at 101.104%; and 2020 at 100%.

For a complete description of the Debentures, reference should be made to the Debenture Indenture, a copy of which is accessible on the SEDAR website at *www.sedar.com* (filed on January 10, 2011, February 22, 2011, July 19, 2012 and January 14, 2013).

Credit Facilities

As at March 1, 2014, Baytex Energy had a $40 million extendible operating loan facility with a chartered bank and a $810 million extendible syndicated loan facility with a syndicate of chartered banks, each of which constitute a revolving credit facility that is extendible annually for a 1, 2, 3 or 4 year period (subject to a maximum four-year term at any time). In the event that the Credit Facilities are not extended before June 14, 2017, indebtedness under the Credit Facilities will be repayable on June 14, 2017. The Credit Facilities contain standard commercial covenants for facilities of this nature. The Credit Facilities do not require any mandatory principal payments prior to maturity. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offer Rates, plus applicable margins. The Credit Facilities are secured by a floating charge over all of Baytex Energy's assets and are guaranteed by Baytex and certain material restricted subsidiaries. The Credit Facilities do not include a term-out feature or a borrowing base restriction. In the event that we do not comply with covenants under the Credit Facilities, our ability to pay dividends to Shareholders may be restricted. See *"Dividends – Dividend Policy"*.

The Credit Facilities contain restrictions on Baytex Energy's ability to make distributions to us, including the declaration or payment of any dividend or distribution to us as the holder of the capital stock of Baytex Energy and the payment of interest or principal on subordinated debt owed to us. Baytex Energy and its subsidiaries are restricted from making distributions to us when (i) a default or event of default under the Credit Facilities has occurred and is continuing, or (ii) distributions would be reasonably expected to have a material adverse effect on or impair the ability of Baytex Energy to fulfill its financial obligations to its lenders under the Credit Facilities. See also "*Risk Factors – Risks Related to our Business and Operations – Our bank credit facilities will need to be renewed prior to June 14, 2017 and failure to renew, in whole or in part, or higher interest charges will adversely affect our financial condition*".

DIVIDENDS

Dividend Policy

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

The amount of future cash dividends, if any, will be subject to the discretion of the Board of Directors and may vary depending on a variety of factors and conditions existing from time to time, including fluctuations in commodity prices, production levels, capital expenditure requirements, debt service requirements, operating costs, royalty burdens and foreign exchange rates. In addition, the payment of dividends by a corporation is governed by the liquidity and insolvency tests described in the ABCA. Pursuant to the ABCA, after the payment of a dividend, we must be able to pay our liabilities as they become due and the realizable value of our assets must be greater than our liabilities and the legal stated capital of our outstanding securities. As at December 31, 2013, our legal stated capital was approximately $2.0 billion. Cash dividends to Shareholders are not assured or guaranteed and there can be no guarantee that Baytex will maintain its dividend policy. See " *– Record of Dividends and Distributions*" and "*Risk Factors*".

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

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

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

Record of Dividends and Distributions

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

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

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

	Distributions per Trust Unit ($)							
Month	**2010**	**2009**	**2008**	**2007**	**2006**	**2005**	**2004**	**2003**
January	0.18	0.18	0.18	0.18	0.15	0.15	0.15	-
February	0.18	0.18	0.18	0.18	0.18	0.15	0.15	-
March	0.18	0.12	0.18	0.18	0.18	0.15	0.15	-
April	0.18	0.12	0.20	0.18	0.18	0.15	0.15	-
May	0.18	0.12	0.20	0.18	0.18	0.15	0.15	-
June	0.18	0.12	0.20	0.18	0.18	0.15	0.15	-
July	0.18	0.12	0.25	0.18	0.18	0.15	0.15	-
August	0.18	0.12	0.25	0.18	0.18	0.15	0.15	-
September	0.18	0.12	0.25	0.18	0.18	0.15	0.15	-
October	0.18	0.12	0.25	0.18	0.18	0.15	0.15	0.15
November	0.18	0.12	0.25	0.18	0.18	0.15	0.15	0.15
December	0.18	0.12	0.25	0.18	0.18	0.15	0.15	0.15
Total	$2.16	$1.56	$2.64	$2.16	$2.13	$1.80	$1.80	$0.45

Dividend Reinvestment Plan

Baytex has a Dividend Reinvestment Plan (the "**DRIP**") that provides a convenient and cost-effective method for eligible holders in Canada to maximize their investment in Baytex by reinvesting their monthly cash dividends to acquire additional Common Shares. At the discretion of Baytex, Common Shares will either be issued from treasury or acquired in the open market at prevailing market prices. Pursuant to the terms of the DRIP, Common Shares issued from treasury are currently issued at a three percent discount to the "average market price" (as defined in the DRIP). Baytex reserves the right at any time to change or eliminate the discount on Common Shares acquired from treasury. Shareholders are not required to participate in the DRIP. A Shareholder who does not participate will continue to receive monthly cash dividends on their Common Shares in the normal manner.

MARKET FOR SECURITIES

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

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
2011[(1)]	58.77	39.18	158,199,516	61.96	36.89	79,445,292
2012	59.40	38.54	153,598,017	59.50	37.40	56,366,309
2013						
January	47.04	43.17	11,685,057	47.09	43.79	2,949,901
February	47.61	42.22	13,235,046	47.47	41.04	3,233,303
March	45.38	42.00	14,229,551	44.21	41.10	3,474,977
April	43.05	36.37	17,625,019	42.50	35.42	4,994,797
May	41.60	37.75	16,525,672	41.47	37.04	5,052,109
June	39.51	36.56	10,374,749	38.22	34.71	3,190,546

	Canada Composite Trading			United States Composite Trading		
	Price Range			Price Range		
	High ($)	Low ($)	Volume Traded	High (US$)	Low (US$)	Volume Traded
July	44.44	37.65	16,395,772	43.08	35.70	3,634,313
August	43.72	40.51	9,083,228	42.34	38.76	3,530,714
September	43.44	40.76	9,125,099	42.20	39.18	3,169,676
October	44.74	40.82	13,112,997	42.84	39.26	2,807,133
November	43.75	41.19	11,651,629	41.84	39.25	4,840,744
December	42.73	40.21	11,807,054	40.16	37.76	3,056,178
2014						
January	42.50	39.18	13,653,728	39.42	35.51	4,269,728
February	41.77	38.80	37,505,330	37.81	35.30	5,612,392

Note:

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

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

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

RATINGS

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

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

Baytex Energy has been assigned a corporate family credit rating of Ba3 and our Debentures have been assigned a credit rating of B1, each with a developing outlook by Moody's Investor Service Inc. ("**Moody's**"). Moody's credit ratings are on a long-term debt rating scale that ranges from AAA to C, which represents the range from highest to lowest quality of such securities rated. According to the Moody's rating system, securities rated "B" are considered speculative and are subject to high credit risk. Moody's appends numerical modifiers 1, 2 and 3 to each generic rating classification from AA through C. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category.

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

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

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

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

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

INTEREST OF INSIDERS AND OTHERS IN MATERIAL TRANSACTIONS

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

AUDITORS, TRANSFER AGENT AND REGISTRAR

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

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

INTERESTS OF EXPERTS

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

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

MATERIAL CONTRACTS

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

(a) the credit agreement in respect of the Credit Facilities (filed on SEDAR on July 22, 2011, July 10, 2012, January 14, 2013 and August 9, 2013);

(b) the Debenture Indenture (filed on SEDAR on January 10, 2011, February 22, 2011, July 19, 2012 and January 14, 2013);

(c) our share award incentive plan (filed on SEDAR on March 14, 2013);

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

(e) the scheme implementation deed between us and Aurora dated February 6, 2014 (filed on SEDAR on February 14, 2014);

(f) the underwriting agreement among us and a syndicate of underwriters co-led by Scotia Capital Inc. and RBC Dominion Securities Inc. dated February 7, 2014 in respect of the issuance of 38,433,000 Subscription Receipts (filed on SEDAR on February 7, 2014); and

(g) the subscription receipt agreement among us, Scotia Capital Inc., RBC Dominion Securities Inc. and Valiant Trust Company dated February 24, 2014 (filed on SEDAR on February 24, 2014).

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

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, Saskatchewan, the United States, North Dakota and Wyoming, all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is 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

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Worldwide supply and demand factors primarily determine oil prices; however, prices are also influenced by regional market 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 exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB. The NEB is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* which received Royal Assent on June 29, 2012 (the "**Prosperity Act**"). In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications under Part VI of the *National Energy Board Act*".

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), 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 exporter to obtain an export licence from the NEB.

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 contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

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

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

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. The maximum royalty payable under the royalty regime is 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula with the maximum royalty payable under the royalty regime set at 36%

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

Producers of oil and natural gas from freehold lands in Alberta are required to pay freehold mineral tax. The freehold mineral tax is a tax levied by the Government of Alberta on the value of oil and natural gas production from non-Crown lands and is derived from the *Freehold Mineral Rights Tax Act* (Alberta). The freehold mineral tax is levied on an annual basis on calendar year production using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. The basic formula for the assessment of freehold mineral tax is: revenue less allocable costs equals net revenue divided by wellhead production equals the value based upon unit of production. If payors do not wish to file individual unit values, a default price is supplied by the Crown. On average, the tax levied is 4% of revenues reported from fee simple mineral title properties.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage oil and gas development and new drilling. For example, the Innovative Energy Technologies Program (the "**IETP**") has the stated objectives of increasing recovery from oil and gas deposits, finding technical solutions to the gas over bitumen issue, improving the recovery of bitumen by in-situ and mining techniques and improving the recovery of natural gas from coal seams. The IETP provides royalty adjustments to specific pilot and demonstration projects that utilize new or innovative technologies to increase recovery from existing reserves.

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;

- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;

- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and

- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

British Columbia

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

The royalty payable in respect of natural gas produced on Crown lands is determined by a sliding scale formula based on a reference price, which is the greater of the average net price obtained by the producer and a prescribed minimum price. For non-conservation gas (not produced in association with oil), the royalty rate depends on the date of acquisition of the oil and natural gas tenure rights and the spud date of the well and may also be impacted by the select price, a parameter used in the royalty rate formula to account for inflation. Royalty rates are fixed for certain classes of non-conservation gas when the reference price is below the select price. Conservation gas is subject to a lower royalty rate than non-conservation gas. Royalties on natural gas liquids are levied at a flat rate of 20% of the sales volume.

Producers of oil and natural gas from freehold lands in British Columbia are required to pay monthly freehold production taxes. For oil, the level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

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

- *Deep Well Royalty Credit Program* providing a royalty credit for natural gas wells defined in terms of a dollar amount applied against royalties, is well specific and applies to drilling and completion costs for vertical wells with a true vertical depth greater than 2,500 metres and horizontal wells with a true vertical depth greater than 1,900 metres (or 2,300 metres if spud before September 1, 2009) and if certain other criteria are met and is intended to reflect the higher drilling and completion costs. Effective on April 1, 2014, the Deep Well Royalty Credit Program will have two tiers – "tier 1" and "tier 2". The existing Deep Well Royalty Credit Program, as described above, will comprise tier 2 of the program. Tier 1 of the program will apply to shallower horizontal wells with a true vertical depth less than 1,900 metres if spud after March 31, 2014;

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay of the re-entry well event that is greater than 2,300 metres and a re-entry date after November 30, 2003; or if the well was spud on or after January 1, 2009, with a true vertical depth to the completion point of the re-entry well event being greater than 2,300 metres;

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

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

- *Marginal Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m^3 for every metre of marginal well depth in the first 12 months of production. To be eligible, wells must have been spudded after May 31, 1998 and the first month of marketable gas production must have occurred between June 2003 and August 2008. Once a well passes the initial eligibility test, a reduction is realized in each month that average daily production is less than 25,000 m^3;

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17 m^3 per metre of depth for exploratory wildcat wells and less than 11 m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000 $m^{3.}$ Effective on April 1, 2014, the Ultra-Marginal Royalty Reduction Program will no longer apply to horizontal wells due to the potential for overlap with shallower horizontal wells eligible for a royalty credit under the Deep Well Royalty Credit Program; and

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

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

The Government of British Columbia also maintains an Infrastructure Royalty Credit Program that provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to facilitate increased oil and gas exploration and production in under-developed areas and to extend the drilling season.

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 3% minimum royalty on affected wells with deep well/deep re-entry credits. The 3% minimum royalty applies to deep wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

In Saskatchewan, the amount payable as a Crown royalty or a freehold production tax in respect of oil depends on the type and vintage of oil, the quantity of oil produced in a month, the value of the oil produced and specified adjustment factors determined monthly by the provincial government. For Crown royalty and freehold production tax purposes, conventional oil is divided into "types", being "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The vintage of oil, being "fourth tier oil", "third tier oil", "new oil" and "old oil", depends on the finished drilling date of a well and is applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (produced from a vertical well having a finished drilling date on or after January 1, 1994 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1994 and before October 1, 2002), fourth tier oil (having a finished drilling date on or after October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after October 1, 2002) or new oil (conventional oil that is not classified as "third tier oil" or "fourth tier oil"). Southwest designated oil uses the same definition of fourth tier oil but third tier oil is defined as conventional oil produced from a vertical well having a finished drilling date on or after February 9, 1998 and before October 1, 2002 or incremental oil from new or expanded waterflood projects with a commencement date on or after February 9, 1998 and before October 1, 2002 and new oil is defined as conventional oil produced from a horizontal well having a finished drilling date on or after February 9, 1998 and before October 1, 2002. For non-heavy oil other than southwest designated oil, the same classification as heavy oil is used but new oil is defined as conventional oil produced from a vertical well completed after 1973 and having a finished drilling date prior to 1994, conventional oil produced from a horizontal well having a finished drilling date on or after April 1, 1991 and before October 1, 2002, or incremental oil from new or expanded waterflood projects with a commencement date on or after January 1, 1974 and before 1994 whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil. Production tax rates for freehold production are determined by first determining the Crown royalty rate and then subtracting the "Production Tax Factor" ("**PTF**") applicable to that classification of oil. Currently the PTF is 6.9 for "old oil", 10.0 for "new oil" and "third tier oil" and 12.5 for "fourth tier oil". The minimum rate for freehold production tax is zero.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional oil and apply at a reference well production rate of 100 m^3 for "old oil", "new oil" and "third tier oil", and 250 m^3 per month for "fourth tier oil". Where average wellhead prices are below the established base prices of $100 per m^3 for third and fourth tier oil and $50 per m^3 for new oil and old oil, base royalty rates are applied. Base royalty rates are 5% for all fourth tier oil, 10% for heavy oil that is third tier oil or new oil, 12.5% for southwest designated oil that is third tier oil or new oil, 15% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 20% for old oil. Where average wellhead prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base oil price. Marginal royalty rates are 30% for all fourth tier oil, 25% for heavy oil that is third tier oil or new oil, 35% for southwest designated oil that is third tier oil or new oil, 35% for non-heavy oil other than southwest designated oil that is third tier or new oil, and 45% for old oil.

The amount payable as a Crown royalty or a freehold production tax in respect of natural gas production is determined by a sliding scale based on the monthly provincial average gas price published by the Saskatchewan government, the quantity produced in a given month, the type of natural gas, and the classification of the natural gas.

Like conventional oil, natural gas may be classified as "non-associated gas" (gas produced from gas wells) or "associated gas" (gas produced from oil wells) and royalty rates are determined according to the finished drilling date of the respective well. Non-associated gas is classified as new gas (having a finished drilling date before February 9, 1998 with a first production date on or after October 1, 1976), third tier gas (having a finished drilling date on or after February 9, 1998 and before October 1, 2002), fourth tier gas (having a finished drilling date on or after October 1, 2002) and old gas (not classified as either third tier, fourth tier or new gas). A similar classification is used for associated gas except that the classification of old gas is not used, the definition of fourth tier gas also includes production from oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of at least 3,500 m^3 of gas for every m^3 of oil, and new gas is defined as oil produced from a well with a finished drilling date before February 9, 1998 that received special approval, prior to October 1, 2002, to produce oil and gas concurrently without gas-oil ratio penalties.

On December 9, 2010, the Government of Saskatchewan enacted the *Freehold Oil and Gas Production Tax Act, 2010* with the intention to facilitate the efficient payment of freehold production taxes by industry. Two new regulations with respect to this legislation are: (i) *The Freehold Oil and Gas Production Tax Regulations, 2012* which sets out the terms and conditions under which the taxes are calculated and paid; and (ii) *The Recovered Crude Oil Tax Regulations*, 2012 which sets out the terms and conditions under which taxes on recovered crude oil that was delivered from a crude oil recovery facility on or after March 1, 2012 are to be calculated and paid.

As with conventional oil production, base prices based on a well reference rate of 250 10^3 m^3/month are used to establish lower limits in the price-sensitive royalty structure for natural gas. Where average field-gate prices are below the established base prices of $1.35 per gigajoule for third and fourth tier gas and $0.95 per gigajoule for new gas and old gas, base royalty rates are applied. Base royalty rates are 5% for all fourth tier gas, 15% for third tier or new gas, and 20% for old gas. Where average well-head prices are above base prices, marginal royalty rates are applied to the proportion of production that is above the base gas price. Marginal royalty rates are 30% for all fourth tier gas, 35% for third tier and new gas, and 45% for old gas**.** The current regulatory scheme provides for **c**ertain differences with respect to the administration of "fourth tier gas" which is associated gas.

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

- *Royalty/Tax Incentive Volumes for Vertical Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 8,000 m^3 for deep development vertical oil wells, 4,000 m^3 for non-deep exploratory vertical oil wells and 16,000 m^3 for deep exploratory vertical oil wells (more than 1,700 metres or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for qualifying exploratory gas wells;

- *Royalty/Tax Incentive Volumes for Horizontal Oil Wells Drilled on or after October 1, 2002* providing reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 6,000 m^3 for non-deep horizontal oil wells and 16,000 m^3 for deep horizontal oil wells (more than 1,700 metres total vertical depth or within certain formations) and after the incentive volume is produced, the oil produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing for a classification of the well as a qualifying exploratory gas well and resulting in a reduced Crown royalty (a Crown royalty rate of the lesser of "fourth tier oil" Crown royalty rate and 2.5%) and freehold tax rates (a freehold production tax rate of 0%) on incentive volumes of 25,000,000 m^3 for horizontal gas wells and after the incentive volume is produced, the gas produced will be subject to the "fourth tier" royalty tax rate;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* whereby incremental production from approved waterflood projects is treated as fourth tier oil for the purposes of Crown royalty and freehold tax calculations;

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

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

- *Royalty/Tax Regime for High Water-Cut Oil Wells* designed to extend the product lives and improve the recovery rates of high water-cut oil wells and granting "third tier oil" royalty/tax rates with a Saskatchewan Resource Credit of 2.5% for oil produced prior to April 2013 and 2.25% for oil produced on or after April 1, 2013 to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

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

Land Tenure

The respective provincial governments predominantly own the rights to crude oil and natural gas located in the western provinces. 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. Private ownership of oil and natural gas also exists in such provinces and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

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

Alberta also has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for all leases and licenses. For leases and licenses issued subsequent to January 1, 2009, shallow rights reversion will be applied at the conclusion of the primary term of the lease or license.

Environmental Regulation

The oil and natural gas industry is currently subject to regulation pursuant to a variety of provincial and federal environmental legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability and the imposition of material fines and penalties.

Federal

Pursuant to the *Prosperity Act*, the Government of Canada amended or repealed several pieces of federal environmental legislation and in addition, created a new federal environment assessment regime that came in to force on July 6, 2012. The changes to the environmental legislation under the *Prosperity Act* are intended to provide for more efficient and timely environmental assessments of projects that previously had been subject to overlapping legislative jurisdiction.

Alberta

The regulatory landscape in Alberta has undergone a transformation from multiple regulatory bodies to a single regulator for upstream oil and gas, oil sands and coal development activity. On June 17, 2013, the Alberta Energy Regulator (the "**AER**") assumed the functions and responsibilities of the former Energy Resources Conservation Board, including those found under the *Oil and Gas Conservation Act* ("**ABOGCA**"). On November 30, 2013, the AER assumed the energy related functions and responsibilities of Alberta Environment and Sustainable Resource Development ("**AESRD**") in respect of the disposition and management of public lands under the *Public Lands Act*. On March 29, 2014, the AER is expected to assume the energy related functions and responsibilities of AESRD in the areas of environment and water under the *Environmental Protection and Enhancement Act* and the *Water Act*, respectively. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as Alberta Energy's responsibility for mineral tenure. The objective behind the transformation to a single regulator is the creation of an enhanced regulatory regime that is efficient, attractive to business and investors, and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size.

The region includes a substantial portion of the Athabasca oilsands area, which contains approximately 82% of the province's oilsands resources and much of the Cold Lake oilsands area.

LARP establishes six new conservation areas and nine new provincial recreation areas. In conservation and provincial recreation areas, conventional oil and gas companies with pre-existing tenure may continue to operate. Any new petroleum and gas tenure issued in conservation and provincial recreation areas will include a restriction that prohibits surface access. In contrast, oilsands companies' tenure has been (or will be) cancelled in conservation areas and no new oilsands tenure will be issued. While new oil sands tenure will be issued in provincial recreation areas, new and existing oil sands tenure will prohibit surface access.

The next regional plan to take effect is the South Saskatchewan Regional Plan ("**SSRP**") which covers approximately 83,764 square kilometres and includes 45% of the provincial population. The SSRP was released in draft form in 2013 and is expected to come into force on April 1, 2014.

With the implementation of the new Alberta regulatory structure under the AER, AESRD will remain responsible for development and implementation of regional plans. However, the AER will take on some responsibility for implementing regional plans in respect of energy related activities.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act* requires proponents to obtain various approvals before undertaking exploration or production work, such as geophysical licences, geophysical exploration project approvals, permits for the exclusive right to do geological work and geophysical exploration work, and well, test hole and water-source well authorizations. Such approvals are given subject to environmental considerations and licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

Saskatchewan

In May 2011, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER implements the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream oil and gas wells, facilities and pipelines. The ABOGCA establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes defunct. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licences and prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month and failure to post the required security deposit may result in the initiation of enforcement action by the AER.

Effective May 1, 2013, the AER implemented important changes to the AB LLR Program that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. Some of the important changes include:

- a 25% increase to the prescribed average reclamation cost for each individual well or facility (which will increase a licensee's deemed liabilities);

- a $7,000 increase to facility abandonment cost parameters for each well equivalent (which will increase a licensee's deemed liabilities);

- a decrease in the industry average netback from a five-year to a three-year average (which will affect the calculation of a licensee's deemed assets, as the reduction from five to three years means the average will be more sensitive to price changes); and

- a change to the present value and salvage factor, increasing to 1.0 for all active facilities from the current 0.75 for active wells and 0.50 for active facilities (which will increase a licensee's deemed liabilities).

These changes will be implemented over a three-year period. The first phase was implemented in May 2013, the second phase will be implemented in May 2014 and the final phase will be implemented in May 2015. The changes to the LLR Program stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

British Columbia

In British Columbia, the Commission implements the Liability Management Rating ("**LMR**") Program, designed to manage public liability exposure related to oil and gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under the LMR Program, the Commission determines the required security deposits for permit holders under the OGAA. The LMR is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed deemed assets will be considered high risk and reviewed for a security deposit. Permit holders who fail to submit the required security deposit within the allotted timeframe may be in non-compliance with the OGAA.

Saskatchewan

In Saskatchewan, the Ministry of Economy implements the Licensee Liability Rating Program (the "**SK LLR Program**"). The SK LLR Program is designed to assess and manage the financial risk that a licensee's well and facility abandonment and reclamation liabilities pose to an orphan fund (the "**Oil and Gas Orphan Fund**") established under the SKOGCA. The Oil and Gas Orphan Fund is responsible for carrying out the abandonment and reclamation of wells and facilities contained within the SK LLR Program when a licensee or WIP is defunct or missing. The SK LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to post a security deposit. The ratio of deemed liabilities to deemed assets is assessed once each month for all licensees of oil, gas and service wells and upstream oil and gas facilities.

Climate Change Regulation

Federal

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

On April 26, 2007, the Government of Canada released "Turning the Corner: An Action Plan to Reduce Greenhouse Gases and Air Pollution" (the "**Action Plan**") which set forth a plan for regulations to address both GHGs and air pollution. An update to the Action Plan, "Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions" was released on March 10, 2008 (the "**Updated Action Plan**"). The Updated Action Plan outlines emissions intensity-based targets, for application to regulated sectors on a facility-specific, sector-wide basis or company-by-company basis. Although the intention was for draft regulations aimed at implementing the Updated Action Plan to become binding on January 1, 2010, the only regulations being implemented are in the transportation and electricity sectors. The federal government indicates that it is taking a sector-by-sector regulatory approach to reducing GHG emissions and is working on regulations for other sectors. Representatives of the Government of Canada have indicated that the proposals contained in the Updated Action Plan will be modified to ensure consistency with the direction ultimately taken by the United States with respect to GHG emissions regulation. In June 2012, the second US-Canada Clean Energy Dialogue Action Plan was released. The plan renewed efforts to enhance bilateral collaboration on the development of clean energy technologies to reduce GHG emissions.

Alberta

As part of Alberta's 2008 Climate Change Strategy, the province committed to taking action on three themes: (a) conserving and using energy efficiently (reducing GHG emissions); (b) greening energy production; and (c) implementing carbon and capture storage.

As part of its efforts to reduce GHG emissions, Alberta introduced legislation to address GHG emissions: the *Climate Change and Emissions Management Act* (the "**CCEMA**") enacted on December 4, 2003 and amended through the *Climate Change and Emissions Management Amendment Act*, which received royal assent on November 4, 2008. The CCEMA is based on an emissions intensity approach and aims for a 50% reduction from 1990 emissions relative to GDP by 2020. The accompanying regulations include the *Specified Gas Emitters Regulation* ("**SGER**"), which imposes GHG limits, and the *Specified Gas Reporting Regulation*, which imposes GHG emissions reporting requirements. Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Alberta is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions.

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of their baseline in the fifth year, 6% of their baseline in the sixth year, 8% of their baseline in the seventh year and 10% of their baseline in the eighth year. The CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of carbon dioxide equivalent. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta will invest $2 billion into demonstration projects that will begin commercializing the technology on the scale needed to be successful. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been, the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

As at year-end 2013, we did not operate any facilities in Alberta that emit more than 100,000 tonnes of carbon dioxide equivalent per year.

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of carbon dioxide equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

In the 2012 Budget, British Columbia announced that the government would undertake a comprehensive review of the carbon tax and its impact on British Columbians. The review covered all aspects of the carbon tax, including revenue neutrality, and considered the impact on the competitiveness of British Columbia businesses such as those in the agriculture sector, and in particular, British Columbia's food producers. After the review last year, British Columbia confirmed that it will keep its revenue-neutral carbon tax, the current carbon tax rates and tax base will be maintained and revenues will continue to be returned through tax reductions.

On April 3, 2008, British Columbia introduced the *Greenhouse Gas Reduction (Cap and Trade) Act* (the "**Cap and Trade Act**"), which received royal assent on May 29, 2008 and partially came into force by regulation of the Lieutenant Governor in Council. It sets a province-wide target of a 33% reduction in the 2007 level of GHG emissions by 2020 and an 80% reduction by 2050. Unlike the emissions intensity approach taken by the federal government and the Government of Alberta, the Cap and Trade Act establishes an absolute cap on GHG emissions. The *Reporting Regulation*, implemented under the authority of the Cap and Trade Act, sets out the requirements for the reporting of the GHG emissions from facilities in British Columbia emitting 10,000 tonnes or more of carbon dioxide equivalent emissions per year beginning on January 1, 2010. Those reporting operations with emissions of 25,000 tonnes or greater are required to have emissions reports verified by a third party. Recent amendments to the Cap and Trade Act repealed past requirements on public-sector organizations, including Crown corporations, to be carbon neutral by 2010, and they are now only required to produce annual carbon reduction plans and reports. Additional regulations that will further enable British Columbia to implement a cap and trade system are currently under development.

As at year-end 2013, we did not operate any facilities in British Columbia that emit more than 10,000 tonnes of carbon dioxide equivalent per year.

Saskatchewan

On May 11, 2009, the Government of Saskatchewan announced *The Management and Reduction of Greenhouse Gases Act* (the "**MRGGA**") to regulate GHG emissions in the province. The MRGGA received Royal Assent on May 20, 2010 and will come into force on proclamation. The MRGGA establishes a framework for achieving the provincial target of a 20% reduction in GHG emissions from 2006 levels by 2020. The MRGGA and related regulations have yet to be proclaimed in force.

United States

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

In addition to regulations governing operations, the federal government and each state have statutes and regulations which govern oil and gas lease terms, including tenure, royalties, production rates and other provisions. Oil and gas lessees are often required to pay annual rental payments to comply with federal, state and private oil and gas lease provisions until production begins or the leases term expires. Upon commencement of production, royalties and production taxes are paid on revenue received from oil and natural gas produced from federal, state and private lands. The royalty and production tax regime is a significant factor in the profitability of oil and natural gas production. Royalties payable on production from lands, other than federal and state lands in the U.S., are determined by negotiations between the private mineral owner and the lessee. Federal, U.S. Indian and state royalties and production taxes in the U.S. are determined by government regulation and are generally calculated as a percentage of the value of the gross production less approved marketing and transportation deductions. The royalty rate payable for federal leases is generally fixed at 1/8th and varies from state to state for leases covering state-owned minerals. State minerals are currently being leased subject to a 3/16th royalty rate in North Dakota and a 1/6th royalty rate in Wyoming. Other royalties and royalty-like interests are from time to time carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalty interests, or net profits interests.

Private mineral ownership in the U.S. is prevalent and generally on lands settled and patented before the early 1900's. The federal government and the state in which the minerals are located also hold ownership to mineral rights. The federal mineral rights are administered by the Bureau of Land Management under the Department of the Interior (the "**BLM**"). These owners, from governmental bodies to private individuals, grant rights to explore for and produce oil and gas pursuant to oil and gas leases, providing for varying consideration, term and royalties. As to those rights held by private owners, all terms and conditions may be negotiated. For those rights held by governmental agencies, typically the terms and conditions of the oil and gas lease have been predetermined by each governing or regulatory body and the consideration is determined by oral bidding. Substantially all of the oil and gas leasehold currently owned by Baytex USA in North Dakota has been granted by private mineral owners and the State of North Dakota. In Wyoming, the largest mineral owner under Baytex USA's oil and gas leasehold is the federal government.

A lease may generally be continued after the primary term 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, the mineral estate is considered the "dominant" estate with the right to extract minerals subject to reasonable use of the surface. Each state has developed and adopted their own statutes that operators must follow both prior to drilling and following drilling including notification requirements and to provide 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.

In the U.S., oil and gas operations are regulated at the federal, state and to a lesser degree county levels of government. At the federal level, well planning and permitting is primarily regulated by the BLM and Bureau of Indian Affairs for operations on public and tribal lands under the *Federal Land Policy and Management Act* and the *National Environmental Policy Act* (the "**NEPA**"). Environmental conservation, cultural and natural resources protection at the federal level are administered by numerous agencies under multiple statutes. The BLM can suspend permit approvals in specific areas while environmental analyses are being conducted and compliance documents required by the NEPA are being prepared (e.g., environmental assessments and environmental impact statements). Environmental planning, permitting and compliance related to media protection and contaminants at the federal level are administered by its Environmental Protection Agency (the "**EPA**") or by various states whose programs have been granted primacy by the EPA. The EPA governs federal legislation, including the *Clean Air Act*, the *Clean Water Act*, the *Resource Conservation and Recovery Act* (other than oil and gas exempt wastes), the *Comprehensive Environmental Response, Compensation and Liability Act*, the *Oil Pollution Act*, the *Emergency Planning and Community Right-to-Know Act*, the *Safe Drinking Water Act* and *Federal Executive Orders*. Baytex USA's operations are subject to various regulations, including those relating to well permits, linear facilities, hydraulic fracturing, underground injection and setbacks (buffers) for environmental protection, including a number of state agencies regulating oil and gas activities.

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

Additional regulations affecting Baytex USA's operations include the following: the approval and promulgation of the Federal Implementation Plan for Oil and Natural Gas Well Production Facilities and the Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution. These regulations provide emission control requirements for Baytex USA's assets, as well as increased monitoring, recordkeeping, reporting, and regulatory oversight.

At the request of Congress, in 2011, the EPA began research under its *Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources*. The purpose of the study is to assess the potential impacts of hydraulic fracturing on drinking water resources, and to identify the driving factors that may affect the severity and frequency of such impacts. The focus is primarily on hydraulic fracturing of shale formations to extract natural gas, with some study of other oil-and gas-producing formations, including tight sands, and coalbeds. The BLM, which regulates oil and gas operations located on federal and tribal lands, published its latest proposed hydraulic fracturing rules on May 16, 2013. The BLM is reportedly in the process of sorting through approximately 1.7 million comments received in response to the proposed rule. The BLM has provided no update regarding a schedule for finalizing the rule.

Congress has also initiated various countermeasures aimed at restricting federal agencies' authority to impose new hydraulic fracturing regulations. The political response from Congress is largely in reaction to the BLM's proposed rules, the lingering EPA study and several other federal agency efforts to study the issue. The intent of these countermeasures is to limit federal over-reach on an issue that is considered best managed at the state level.

North Dakota has updated their regulation on hydraulic fracturing disclosure. The requirements fall within two basic categories: (i) design and operational requirements; and (ii) information disclosure. North Dakota requires operators to disclose information about the chemicals used in their completions. North Dakota requires the posting of this information on the internet-based chemical registry FracFocus. FracFocus is operated by the Ground Water Protection Council, a group of state water officials, and the Interstate Oil and Gas Compact Commission, an association of oil and gas producing states. The online registry was created in 2011, in response, at least in part, to concerns from landowners about the chemical content of fracturing fluids that were being injected into oil and gas wells on their land as well as adjacent properties. FracFocus is widely accepted among the petroleum industry, and Baytex USA has determined to utilize the registry in all four states in which it operates. Currently, FracFocus lists over 700 companies as registry participants.

Implementation of more stringent environmental regulations on Baytex USA's operations could affect the capital and operating expenditures and plans for Baytex USA's operations. Baytex USA minimizes the potential of these impacts to its operations in many ways, including through the participation and membership in trade organizations, such as North Dakota Petroleum Council, Independent Petroleum Association of America and Western Energy Alliance. In addition, to the agencies that directly regulate oil and gas operations, there are other state and local conservation and environmental protection agencies that regulate air quality, state water quality, fish, wildlife, visual quality, transportation, noise, spills, incidents and transportation.

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

ADDITIONAL INFORMATION

Additional information relating to us can be found on the SEDAR website at *www.sedar.com* and on our website at *www.baytexenergy.com.* Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our Information Circular - Proxy Statement for the annual meeting of Shareholders to be held on May 15, 2014. Additional financial information is contained in our consolidated financial statements for the year ended December 31, 2013 and the related management's discussion and analysis which are accessible on the SEDAR website at *www.sedar.com*. For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

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Website: *www.baytexenergy.com*

APPENDIX A

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

Management of Baytex Energy Corp. ("**Baytex**") is responsible for the preparation and disclosure of information with respect to Baytex's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

The Reserves Committee of the Board of Directors of Baytex (the "**Reserves Committee**") has:

(a) reviewed Baytex's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

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

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

(c) the content and filing of this report.

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

(signed) "*James L. Bowzer*"
James L. Bowzer
President and Chief Executive Officer

(signed) "*W. Derek Aylesworth*"
W. Derek Aylesworth
Chief Financial Officer

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

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

March 25, 2014

APPENDIX B

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

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

1. We have evaluated Baytex's reserves data as at December 31, 2013. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2013, estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Baytex evaluated by us for the year ended December 31, 2013, 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 Associates Limited	Evaluation of the P&NG Reserves of Baytex Energy Corp. (As of December 31, 2013). Preparation Date: February 28, 2014	Canada	Nil	$3,592,872	Nil	$3,592,872
		United States	Nil	716,907	Nil	716,907
		Total	Nil	$4,309,779	Nil	$4,309,779

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not evaluate.

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

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

Executed as to our report referred to above on February 28, 2014.

Sproule Associates Limited

(signed) "*Cameron P. Six*"
Cameron P. Six, P.Eng.
Vice-President, Unconventional and Director

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

(signed) "*Harry J. Helwerda*"
Harry J. Helwerda, P.Eng., FEC, FGC (Hon.)
President, Chief Operating Officer and Director

(signed) "*Steven J. Golko*"
Steven J. Golko, P.Eng.
Partner

(signed) "*Matthew J. Tymchuk*"
Matthew J. Tymchuk, P.Eng.
Petroleum Engineer and Partner

(signed) "*Jason E. Robottom*"
Jason E. Robottom, P.Eng.
Petroleum Engineer and Partner

APPENDIX C

BAYTEX ENERGY LTD.

AUDIT COMMITTEE

MANDATE AND TERMS OF REFERENCE

ROLE AND OBJECTIVE

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

The objectives of the Committee are to:

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