ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2016

March 17, 2017

TABLE OF CONTENTS

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids

Natural Gas

Mcf	thousand cubic feet
MMcf	million cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
MMbtu	million British Thermal Units
Bcf	billion cubic feet
GJ	gigajoule
GJ/d	gigajoules per day
MM	Million

Other

AECO	the natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 Mcfe of natural gas
BOE/d	barrel of oil equivalent per day
m^3	cubic metres
MBOE	1,000 barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent
Mcfe/d	thousand cubic feet of gas equivalent per day
MMcfe/d	million cubic feet of gas equivalent per day
$000s or $M	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

OIL AND GAS INFORMATION ADVISORIES

Where any disclosure of reserves data is made in this Annual Information Form that does not reflect all of the reserves of Bellatrix, the reader should note that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

All production and reserves quantities included in this Annual Information Form (including the Appendices hereto) have been prepared 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 United States companies. Nevertheless, as part of Bellatrix's Annual Report on Form 40-F for the year ended December 31, 2016 filed with the SEC, Bellatrix has disclosed proved reserves quantities using the standards contained in SEC Regulation S-X, and the standardized measure of discounted future net cash flows relating to proved oil and gas reserves determined in accordance with the U.S. Financial Accounting Standards Board, "Extractive Activities – Oil and Gas", which disclosure complies with the SEC's rules for disclosing oil and gas reserves.

Disclosure provided herein in respect of BOEs or Mcfes may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 Bbl:6 Mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6Mcf:1Bbl, utilizing a conversion on a 6Mcf:1Bbl basis may be misleading as an indication of value.

CONVERSIONS

To Convert From	To	Multiply By
Mcf	Cubic metres	28.174
Cubic metres	Cubic feet	35.494
Bbls	Cubic metres	0.159
Cubic metres	Bbls oil	6.292
Feet	Metres	0.305
Metres	Feet	3.281
Miles	Kilometres	1.609
Kilometres	Miles	0.621
Acres (Alberta)	Hectares	0.400
Hectares (Alberta)	Acres	2.500
Acres (British Columbia)	Hectares	0.405
Hectares (British Columbia)	Acres	2.471

CERTAIN DEFINITIONS

In this Annual Information Form, the following words and phrases have the following meanings, unless the context otherwise requires:

"**2017 net capital budget**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2017 Capital Budget*";

"**ABCA**" means the *Business Corporations Act* (Alberta), R.S.A. 2000, c. B-9, as amended, including the regulations in respect thereof;

"**Applicable Securities Laws**" means all applicable securities laws, the respective regulations, rules and orders made thereunder, and all applicable policies and notices issued by the securities regulatory authorities of Canada;

"**Bellatrix**", the "**Corporation**", "**we**", "**us**" or "**our**" means Bellatrix Exploration Ltd.;

"**Bellatrix Alder Flats Gas Plant**" means the O'Chiese Ness-Ohpawganu'ck deep-cut gas plant in the Alder Flats area of Alberta;

"**Board**" means the board of directors of Bellatrix;

"**CNOR**" means Canadian Non-Operated Resources Corp.;

"**CNOR Joint Venture**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2014 Joint Ventures and Asset Acquisitions and Divestures*";

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum;

"**Common Shares**" means the common shares in the capital of Bellatrix;

"**Consolidated Total Debt**" means all debt of the Corporation on a consolidated basis determined in accordance with Canadian generally accepted accounting principles and without duplication. The Corporation's calculation of Consolidated Total Debt excludes decommissioning liabilities and deferred tax liability. The calculation includes outstanding letters of credit, bank debt, Senior Notes, finance lease obligations, deferred lease inducements and net working capital deficiency (excess), calculated as working capital deficiency excluding current commodity contract assets and liabilities;

"**Convertible Debentures**" has the meaning ascribed to such term under the heading "*General Development of our Business – Convertible Debenture and Subscription Receipt Offering*";

"**Convertible Debenture and Subscription Receipt Offering**" has the meaning ascribed to such term under the heading "*General Development of our Business – Convertible Debenture and Subscription Receipt Offering*";

"**Credit Facilities**" has the meaning ascribed to such term under the heading "*Borrowings*";

"**Debenture Indenture**" means the indenture dated August 9, 2016 between Bellatrix and Computershare Trust Company of Canada, as trustee, pursuant to which the Convertible Debentures were issued;

"**EBITDA**" means earnings before interest, taxes, depreciation and amortization. EBITDA is calculated based on terms and definitions set out in the agreement governing the Credit Facilities, which adjusts net income for financing costs, certain specific unrealized and non-cash transactions, acquisition and disposition activity and is calculated based on a trailing twelve month basis;

"**GORR**" means gross overriding royalty;

"**Grafton**" means Grafton Energy Co I Ltd.;

"**Grafton Joint Venture**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2014 Joint Ventures and Asset Acquisitions and Divestures*";

"**gross**" means:

(a) in relation to our interest in production and reserves, our "company gross" reserves, which are our working 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;

"**Harmattan Transaction**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2016 Joint Ventures and Asset Acquisitions and Divestures*";

"**InSite**" means InSite Petroleum Consultants Ltd., independent oil and gas reservoir engineers;

"**InSite Report**" means the report prepared by InSite dated March 7, 2017 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2016;

"**Keyera**" means Keyera Partnership;

"**Keyera Transaction**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2016 Joint Ventures and Asset Acquisitions and Divestures*";

"**net**" means:

(a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalties 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 the working interest we own;

"**NI 51-101**" means National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities*;

"**NI 51-102**" means National Instrument 51-102 - *Continuous Disclosure Obligations*;

"**NYSE**" means the New York Stock Exchange;

"**NYSE MKT**" means the NYSE MKT stock exchange;

"**O'Chiese**" means O'Chiese Gas Plant GP Inc.;

"**OPEC**" means the Organization of the Petroleum Exporting Countries;

"**Orange Capital**" means Orange Capital LLC;

"**Pembina Cardium Transaction**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2016 Joint Ventures and Asset Acquisitions and Divestures*";

"**Preferred Shares**" means the preferred shares issuable pursuant to the Corporation's articles;

"**SEC**" means the U.S. Securities and Exchange Commission;

"**Senior Debt**" means Consolidated Total Debt, excluding any unsecured or subordinated debt (Senior Notes and the liability component of the Convertible Debentures). Senior Debt is calculated based on terms and definitions set out in the agreement governing the Credit Facilities;

"**Senior Notes**" means the 8.500% senior unsecured notes due 2020 issued by the Corporation pursuant to the Senior Note Indenture;

"**Senior Note Indenture**" means the indenture dated May 21, 2015 Between Bellatrix and U.S. Bank National Association, as trustee, pursuant to which the Senior Notes were issued;

"**Sproule**" means Sproule Associates Limited;

"**Subscription Receipt Agreement**" means the subscription receipt agreement dated August 9, 2016 between Bellatrix and National Bank Financial Inc. and Computershare Trust Company of Canada, providing for the issue of subscription receipts pursuant to the Convertible Debenture and Subscription Receipt Offering;

"**Subscription Receipts**" has the meaning ascribed to such term under the heading "*General Development of our Business – Convertible Debenture and Subscription Receipt Offering*";

"**TSX**" means the Toronto Stock Exchange; and

"**U.S. or United States**" means the United States of America, its territories and possessions, any states of the United States and the District of Columbia.

Certain other terms used herein but not defined herein are defined in NI 51-101 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101.

Unless otherwise specified, information in this Annual Information Form is as at the end of the Corporation's most recently completed financial year, being December 31, 2016.

All dollar amounts herein are in Canadian dollars, unless otherwise stated.

FORWARD-LOOKING STATEMENTS

Certain of the statements contained herein including, without limitation, management plans and assessments of future plans and operations, the Corporation's expected 2017 capital budget, expected timing for spending capital associated with certain joint venture arrangements, expected costs and timing of bringing on stream of certain plants and facilities, the expected increase in operating costs relating to the Keyera Transaction, Bellatrix's future business plan and strategy, Bellatrix's criteria for evaluating acquisitions and other opportunities, Bellatrix's intentions with respect to future acquisitions and other opportunities, timing of bringing new wells on stream, production estimates, plans with respect to the Corporation's facilities, drilling and completion plans, plans and timing for development of undeveloped and probable reserves, timing of when the Corporation may be taxable, estimated abandonment and reclamation costs, plans regarding hedging, wells to be drilled, the weighting of commodity expenses, and capital expenditures and the nature of capital expenditures and the timing and method of financing thereof, may constitute "forward-looking statements" or "forward-looking information" within the meaning of Applicable Securities Laws (as defined herein) (collectively "**forward-looking statements**"). Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue", "shall", "estimate", "expect", "propose", "might", "project", "predict", "forecast" and similar expressions may be used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources and the risk factors outlined under "Risk Factors" and elsewhere herein. The recovery and reserve estimates of Bellatrix's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements.

Forward-looking statements are based on a number of factors and assumptions which have been used to develop such forward-looking statements but which may prove to be incorrect. Although Bellatrix believes that the expectations reflected in such forward-looking statements are reasonable, undue reliance should not be placed on forward-looking statements because Bellatrix can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified in this document, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which Bellatrix operates; the timely receipt of any required regulatory approvals; the ability of Bellatrix to obtain qualified staff, equipment and services in a timely and cost efficient manner; drilling results; the ability of the operator of the projects which Bellatrix has an interest in, to operate the field in a safe, efficient and effective manner; the ability of Bellatrix to obtain financing on acceptable terms; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; the timing and costs of pipeline, storage and facility construction and expansion and the ability of Bellatrix to secure adequate product transportation; future oil and natural gas prices; currency, exchange and interest rates; the regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which Bellatrix operates; and the ability of Bellatrix to successfully market its oil and natural gas products.

Readers are cautioned that the foregoing list of factors is not exhaustive. Additional information on these and other factors that could affect Bellatrix's operations and financial results are included in reports on file with Canadian and United States securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), through the SEC website (www.sec.gov), and at Bellatrix's website (www.bellatrixexploration.com). Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and Bellatrix assumes no obligation to update or review them to reflect new events or circumstances except as required by Applicable Securities Laws.

Forward-looking statements contained herein concerning the oil and gas industry and Bellatrix's general expectations concerning this industry are based on estimates prepared by management using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which Bellatrix believes to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While Bellatrix is not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

BACKGROUND

General

Bellatrix is a growth oriented oil and gas exploration company based in Calgary which owns and assumed, directly or indirectly, all of the assets and liabilities, respectively, of True Energy Trust pursuant to a plan of arrangement completed on November 1, 2009. Under the plan of arrangement, True Energy Inc. and True Newco Inc. were amalgamated under the ABCA to form a new corporation which was subsequently amalgamated under the ABCA with 1485166 Alberta Ltd. to form Bellatrix.

On December 11, 2013, Bellatrix was amalgamated with Angle and its subsidiary, Angle Resources Inc., under the ABCA and continued under the name "Bellatrix Exploration Ltd." pursuant to the Angle Arrangement.

Bellatrix does not have, and at December 31, 2016 did not have, any material subsidiaries.

Bellatrix's principal, head office and registered office is located at 1920, 800 – 5th Avenue S.W., Calgary, Alberta T2P 3T6.

The Common Shares trade on the TSX and the NYSE under the symbol "BXE".

GENERAL DEVELOPMENT OF OUR BUSINESS

The following is a summary description of the development of our business since January 1, 2014.

2014 Joint Ventures and Asset Acquisitions and Divestures

Grafton Joint Venture

In 2013, Bellatrix entered into a joint venture with Grafton to accelerate the development of a portion of Bellatrix's undeveloped land holdings in the Willesden Green and Brazeau areas of West-Central Alberta (the "**Grafton Joint Venture**"). Pursuant to the Grafton Joint Venture, Grafton was to contribute 82%, or $200 million, to participate in an expected 58 Spirit River and Cardium well program. On April 10, 2014, Bellatrix announced that Grafton elected to exercise an option to increase its committed capital investment pursuant to the Grafton Joint Venture by an additional $50 million, for a total commitment of $250 million. Grafton's increased capital investment supported the accelerated development of a portion of the Corporation's undeveloped land holdings. Under the agreement, Grafton earned 54% of Bellatrix's working interest in each well drilled in the well program until payout (being recovery of Grafton's capital investment plus an 8% return) on the total program, reverting to 33% of the Corporation's working interest after payout. At any time after payout of the entire program, Grafton has the option to elect to convert all wells from the 33% working interest to a 17.5% GORR on Bellatrix's pre-joint venture working interest. If there is a change of control of Bellatrix, Grafton has the right to cause the Corporation to acquire Grafton's earned working interest or GORR, as applicable, at the same price attributable to those particular assets as the transaction resulting in the change of control.

CNOR Joint Venture

On September 29, 2014, the Corporation entered into a new multi-year joint venture arrangement with CNOR, a non-operated oil and gas company managed by Grafton Asset Management Inc. pursuant to which CNOR has committed $250 million in capital towards future accelerated development of a portion of the Corporation's undeveloped land holdings (the "**CNOR Joint Venture**"). Under the terms of the agreement, commencing on or before October 1, 2015 Bellatrix was to propose development plans for approval by a management committee comprised of representatives of Bellatrix and CNOR. The deadline to propose an initial development plan was subsequently extended to October 1, 2017. See "*2016 Joint Ventures and Asset Acquisitions and Divestures*".

Unless otherwise specified in an approved development plan, CNOR will pay 50% of the drilling, completion, equipping and tie-in capital expenditures in order to earn 33% of the Corporation's working interest before payout and automatically converting to a 10.67% GORR on Bellatrix's pre-joint venture working interest after payout (being recovery of CNOR's capital investment plus an 8% return on investment). If any development plan Bellatrix proposes is not approved within 60 days of the Corporation's submission, such plan will not be funded under the CNOR Joint Venture arrangement, and thereafter neither party will have any obligation to propose, consider or fund any additional proposed development plans.

Tuck-In Acquisitions

In September 2014, the Corporation completed a tuck-in acquisition of working-interests in its core Ferrier area in West Central Alberta, extending the Corporation's Cardium light oil resource play. The acquired assets included current low decline rate net production of approximately 300 BOE/d (24% oil and liquids and 76% natural gas) (current at the time of the acquisition) and included 8 gross (7.0 net) sections of Cardium mineral rights and 3 gross (1.2 net) sections of Mannville prospective lands. Bellatrix acquired the assets for a net purchase price of $13.9 million, which was funded using the Credit Facilities.

The Corporation also entered into a farmin arrangement encompassing 12 gross (9.4 net) sections of Mannville rights and 6 gross (3.5 net) sections Cardium rights in the Ferrier area of West Central Alberta. Under the farmin arrangement, the Corporation committed to drill a minimum of 6 wells into the Cardium interval and 6 wells into the Mannville interval. By drilling these wells, Bellatrix earned, or will earn, the farmor's entire working interest in either the Cardium or Mannville for each section drilled, but reserving a 15% GORR payable on Mannville wells and a 7.5% to 12% GORR payable on Cardium wells to the farmee. After drilling all commitment wells, Bellatrix has the right to drill additional option wells to earn the remaining sections of Cardium and Mannville rights on similar terms. The balance of this farm-in arrangement has been completed with only 2 Cardium wells remaining to be drilled. The Corporation was also active in Alberta land sales in 2014 acquiring 2 gross (2 net) sections of mineral rights in the Mannville and Cardium intervals in the highly prospective Alder Flats area in Central Alberta for $4.3 million. In connection with the aforementioned tuck-in acquisition and farmin arrangement, the Corporation increased its 2014 net capital budget to $530 million.

Alder Flats Acquisitions

During the fourth quarter of 2014, the Corporation completed the acquisition of complementary assets within its core Alder Flats area of west central Alberta (greater Ferrier region) for total adjusted cash consideration of $33.0 million. Approximately 720 BOE/d of unrestricted production (77% natural gas, 23% liquids) (current at the time of acquisition) was acquired in the transaction from approximately 33 gross (5 net) sections of land at Alder Flats, representing largely joint interest lands where Bellatrix currently maintains existing working interest rights. Production at the time of acquisition was largely from the Mannville formation, with minor contributions from the Belly River, Rock Creek and other formations. The effective date of the transaction was September 1, 2014.

Also during the fourth quarter of 2014, the Corporation completed the acquisition of assets in the Alder Flats area of west central Alberta (greater Ferrier region) from a senior oil and gas producer for total cash consideration of approximately $118 million with an effective date of November 1, 2014. The acquisition added approximately 2,200 BOE/d of unrestricted production (80% natural gas, 20% liquids) (current at the time of the acquisition), and largely represented the consolidation of working interest ownership from existing wellbores and Mannville formation rights.

Transfer of Interests in Bellatrix Alder Flats Gas Plant

During the fourth quarter of 2014, Bellatrix completed the transfer at cost of minority interests in the Bellatrix Alder Flats Gas Plant and related pipeline infrastructure to Keyera and O'Chiese. Under the agreed upon terms, Keyera and O'Chiese Energy Limited Partnership (as successor to O'Chiese) participate as 35% and 5%, respectively, minority interest owners in the two proposed phases of the Bellatrix Alder Flats Gas Plant and related plant infrastructure. Following the transaction, the Corporation retained a 60% ownership interest in and remained the operator of the Bellatrix Alder Flats Gas Plant.

2014 Public Offering of Common Shares

On June 5, 2014, the Corporation closed a bought deal offering of 18,170,000 Common Shares at a price of $9.50 per Common Share for aggregate gross proceeds of $172,615,000.

Listing on the NYSE

On October 6, 2014, Bellatrix transferred the listing of the Common Shares from NYSE MKT to the NYSE.

2014 Firm Processing Agreement

On December 2, 2014, the Corporation announced that it had entered into an agreement with Keyera for 19 MMcf/d of firm service processing capacity beginning on such date, increasing to 30 MMcf/d on April 1, 2016, at Keyera's Strachan deep-cut gas plant. The Keyera Strachan plant is well connected to multiple gathering pipelines and has inlet compression, gas dehydration and deep-cut natural gas liquids recovery.

2014 Appointment of Directors and Agreement with Orange Capital

On December 15, 2014, Bellatrix announced that Daniel Lewis and Steven J. Pully would be appointed directors of the Corporation, effective January 1, 2015. In connection with the appointment of Messrs. Lewis and Pully, Bellatrix entered into an agreement with Orange Capital, pursuant to which Orange Capital agreed to abide by certain standstill provisions until November 30, 2015. In addition pursuant to the agreement, the Corporation agreed to nominate Messrs. Lewis and Pully (or two other nominees of Orange Capital acceptable to the Board, acting reasonably) at the 2015 annual shareholders meeting of the Corporation.

2015 Joint Ventures and Asset Acquisitions and Divestures

Grafton Joint Venture

During the second quarter of 2015 the funding period for the initial $200 million commitment under the Grafton Joint Venture was extended to December 31, 2015 (from June 26, 2015) which funding obligation was satisfied by Bellatrix and Grafton by that date.

TCA Joint Venture

In 2013, Bellatrix entered into a joint venture partnership with TCA Energy Ltd., a Canadian incorporated special purpose vehicle for Troika Resources Private Equity Fund based in Seoul, South Korea. Pursuant to the agreement forming the joint venture, Bellatrix and TCA Energy Ltd. agreed to drill and develop lands in the Ferrier Cardium area of West Central Alberta. Effective November 10, 2015, Bellatrix and TCA Energy Ltd. agreed to discharge the remainder of the drilling program under the joint venture. As a result, Bellatrix has no further obligations to drill additional wells thereunder. A total of 49 gross wells (24.5 net), including 3 megabores that each earned two sections of land were successfully drilled under the joint venture.

Pipeline Dispositions

In the second quarter of 2015, Bellatrix disposed of its 100% working interest in a newly constructed condensate pipeline to a midstream purchaser for gross proceeds of approximately $8.6 million. In the third quarter of 2015, the Corporation disposed of its 80% working interest in a 7.1 km pipeline in the west Pembina area of Alberta to a midstream purchaser for gross proceeds of approximately $8.4 million. Under the terms of the sale agreement Bellatrix agreed to an extension of its firm service at a certain processing facility owned by the purchaser by an additional 12 months with a volume commitment in the extension period of 50 MMcf/d.

2015 Senior Note Offering

On May 21, 2015, Bellatrix completed a private offering of US$250 million of 8.500% senior unsecured notes due 2020 (the "**Senior Notes**"). Bellatrix used the net proceeds of approximately $293 million from the Senior Note offering to partially repay borrowings outstanding under the Credit Facilities. For additional information relating to the Senior Notes, see "*Borrowings – Senior Notes*".

Commissioning and Operation of Phase 1 of the Bellatrix Alder Flats Gas Plant

During the second quarter of 2015, Bellatrix successfully completed construction of phase 1 of the Bellatrix Alder Flats Gas Plant ahead of schedule and on budget. Initial start-up of the Bellatrix Alder Flats Gas Plant commenced on May 22, 2015. The Bellatrix Alder Flats Gas Plant successfully averaged 101% utilization through its first two full quarters of operation, providing significant benefits including reduced costs, enhanced gas liquids extraction, and improved operational reliability.

Mutual Expiration of the Shareholder Agreement with Orange Capital

On December 1, 2015, Bellatrix announced that the Corporation and Orange Capital mutually agreed to allow the expiration, as of November 30, 2015, of the shareholder agreement entered into on December 12, 2014.

2016 Joint Ventures and Asset Acquisitions and Divestures

Grafton Joint Venture and Asset Acquisition

On January 18, 2016, Bellatrix and Grafton agreed to extend the funding period for the remaining $50 million commitment under the Grafton Joint Venture to December 31, 2016 (from June 26, 2016).

In the second quarter of 2016, Bellatrix entered into an agreement with Grafton to acquire producing assets within the Corporation’s core Ferrier area for $29.2 million with consideration payable in Common Shares (the "**Grafton Issuance**"). The acquired assets were originally earned by Grafton pursuant to the Grafton Joint Venture and consisted of Grafton’s interest in 18 gross wells and related lands, which were already operated by Bellatrix. The acquired assets produced an average of approximately 2,000 boe/d net to Grafton in May, 2016.

On December 5, 2016, and pursuant to the terms of the Grafton Joint Venture, Grafton provided notice to Bellatrix to terminate the funding period and as a result Bellatrix and Grafton have no further obligations to drill any additional wells pursuant to the Grafton Joint Venture.

CNOR Joint Venture

On September 29, 2016, the parties amended the terms of the CNOR Joint Venture to extend the funding period to December 31, 2020. As a result, Bellatrix is required to propose a joint development plan on or before October 1, 2017 with the expectation that the funds will be primarily spent between 2018 through 2020.

Facilities Monetization

Effective May 3, 2016, Bellatrix monetized certain production facilities for cash proceeds of $75 million. The Corporation maintained operatorship and preferential access to such facilities and will pay an annual rental fee over the duration of the agreement. Bellatrix retained the option to repurchase the facilities at any time during the term of the agreement.

Disposition of Interest in Bellatrix Alder Flats Gas Plant

On August 9, 2016, Bellatrix completed the disposition of a 35% interest in the Bellatrix Alder Flats Gas Plant to Keyera Partnership ("**Keyera**") for total cash consideration of $112.5 million (the "**Keyera Transaction**"). A portion of the cash consideration paid by Keyera represents a prepayment by Keyera of 35% of the estimated future construction costs of phase 2 of the Bellatrix Alder Flats Gas Plant. As part of the transaction the Corporation and Keyera entered into a midstream services and governance agreement pursuant to which Bellatrix will, for a 10 year term, have exclusive access to approximately 80.5 mmcf/d of post-phase 2 commissioning capacity. In exchange for exclusive access to the purchased capacity during the term, Keyera will be entitled to receive, on an annual basis, a guaranteed fee calculated with reference to the capital fees that Keyera will otherwise receive in accordance with the terms of the construction, ownership and operation agreement governing the Bellatrix Alder Flats Gas Plant. The Corporation remains operator and continues to hold a 25% interest in the Bellatrix Alder Flats Gas Plant with an option to reacquire a 5% interest in the plant near the end of the final year of the agreement with Keyera for a cost of $8 million. The proceeds from the sale were used to reduce the indebtedness of the Corporation under the Credit Facilities.

Asset Dispositions

In the fourth quarter of 2016, the Corporation completed two separate dispositions of non-core assets. In November 2016, Bellatrix completed the sale of certain Cardium focused assets in the greater Pembina area of Alberta for $47 million. The Corporation received $42 million of cash consideration and was issued 2,171,667 common shares of InPlay Oil Corp., the purchaser of the assets (the "**Pembina Cardium Transaction**") (the common shares of InPlay Oil Corp. are listed on the TSX under the symbol "IPO"). In December 2016, Bellatrix completed the sale of certain non-core assets in the greater Harmattan area of Alberta for $80 million, comprised of $65 million of net cash proceeds and a $15 million vendor take back loan (the "**Harmattan Transaction**"). The cash proceeds from both asset dispositions were used to reduce the indebtedness of the Corporation under the Credit Facilities.

Shelf Prospectus Renewal

On May 31, 2016, Bellatrix filed a short form base shelf prospectus in each of the Provinces of Canada except Quebec, and in the United States, that will enable the Corporation, from time to time until June 2018, to offer for sale up to $500 million of Common Shares, Preferred Shares, subscription receipts, warrants, or units comprising any combination thereof.

Convertible Debentures and Subscription Receipt Offering

On August 9, 2016, the Corporation completed the issuance and sale of extendible unsecured subordinated convertible debentures for an aggregate principal amount of $50 million (the "**Convertible Debentures**") and 25,000,000 subscription receipts at a price of $1.20 per subscription receipt, for gross proceeds of $80 million (the "**Subscription Receipt Offering**"). In connection with the offering, Bellatrix filed a short-form prospectus in all provinces in Canada, other than Quebec. Pursuant to the Subscription Receipt Agreement, as a result of the closing of the Keyera Transaction, Common Shares were issued on the automatic conversion of the subscription receipts. The net proceeds from the offering were primarily used to reduce the Corporation's indebtedness under the Credit Facilities. For additional information relating to the Convertible Debentures, see "*Borrowings – Convertible Debentures*".

2016 Canadian Development Expenses Flow-Through Financing

In October 2016, the Corporation issued on a private placement "flow-through" basis, in respect of Canadian Development Expenses, Common Shares at a price of $1.18 per Common Share resulting in gross proceeds of $10 million (the "**CDE Flow-Through Issuance**"). Proceeds from such private placement were used to partially finance the Corporation's drilling and completion expenditures during 2016.

2016 Borrowing Base Reductions and Financial Covenants Amendments

In connection with the monetization of certain production facilities, as described above, on May 3, 2016 Bellatrix agreed to an interim reduction in its borrowing base to $460 million, with a resulting $65 million operating facility and a $395 million syndicated facility. On July 18, 2016, the Corporation announced the completion of its semi-annual borrowing base redetermination and the renewal of its syndicated credit facilities (the semi-annual redetermination was initially scheduled to be completed in May but was deferred to July). As a result of the redetermination, Bellatrix's borrowing base was reduced to $365 million, with a resulting $210 million revolving facility (maturity date initially set at July 1, 2017 but revised on September 30, 2016 to a maturity date of October 1, 2017), and a $155 million non-revolving facility (maturity date set at November 11, 2016). Following the completion of the Keyera Transaction and the Convertible Debenture and Subscription Receipt Offering, the revolving facility was reduced to $160 million and the amount outstanding under the non-revolving facility was reduced to $13 million. Concurrent with the closing of the Pembina Cardium Transaction, the Corporation repaid in full the non-revolving facility and Bellatrix completed the November semi-annual borrowing base redetermination and the renewal of the Credit Facilities. As a result, total commitments under the Credit Facilities were reduced to $130 million. Upon the closing of the Pembina Cardium Transaction, the Corporation repaid in full the non-revolving facility. Following the closing of the Harmattan Transaction in December 2016, the borrowing base under the Credit Facilities was redetermined at $100 million with approximately $80 million of available liquidity (excluding letters of credit). For additional information relating to the Credit Facilities, see "*Borrowings – Credit Facilities*".

NYSE Continued Listing Standards Notice

In August 2016, Bellatrix received a continued listing standards notice from the NYSE as a result of the average closing price of the Corporation's Common Shares being less than US$1.00 per share over a period of 30 consecutive trading days. Bellatrix had six months following receipt of such notification to regain compliance with the minimum share price requirement. On February 3, 2017, Bellatrix announced that it had received an extension to regain compliance until the Corporation's upcoming 2017 annual shareholder meeting since the Corporation would require shareholder approval for any corporate action designed to regain compliance. At Bellatrix's annual shareholder meeting to be held on May 17, 2017 shareholders may be asked to consider a potential proposal to regain compliance.

2017 Capital Budget

On January 5, 2017, the Corporation announced a 2017 net capital budget of $105 million. Bellatrix anticipates directing approximately $70 million of its net budget to drilling and completion activity, $13 million toward its share of the construction of phase 2 of the Bellatrix Alder Flats Gas Plant, $7 million toward other minor infrastructure projects, and $15 million in other capital (including, general and administrative costs, capitalized interest, and other minor capital investments). In addition, pursuant to the Keyera Transaction, Bellatrix will also fund the previously received prepayment portion of Keyera's 35% share of 2017 costs of construction of phase 2 of the Bellatrix Alder Flats Gas Plant during 2017, estimated at approximately $18.8 million.

Significant Acquisitions

The Corporation has not completed any acquisitions that would be considered significant pursuant to NI 51-102 since January 1, 2014.

DESCRIPTION OF BUSINESS

Business Plan and Growth Strategies

Bellatrix is a Western Canadian based growth oriented oil and gas company engaged in the exploration for, and the acquisition, development and production of oil and natural gas reserves in the provinces of Alberta, British Columbia and Saskatchewan. The business plan of Bellatrix is to create sustainable and profitable per share growth in reserves, production and cash flow in the oil and gas industry. To accomplish this, Bellatrix pursues an integrated growth strategy with active development and exploration drilling within its core areas, together with focused acquisitions and strategic joint ventures, and maintenance of a flexible financial position. Bellatrix will continue to target areas and prospects that it believes could result in meaningful reserve and production additions.

Bellatrix will continue to pursue internal and external generation of exploration plays that have low to medium risk and multi-zone potential and intends to maintain a balance between exploration, exploitation and development drilling targeting both oil and natural gas reserves over the course of the next several years. Bellatrix considers asset and corporate acquisition opportunities from time to time that meet Bellatrix's business parameters.

In reviewing potential opportunities, Bellatrix will use the most current methodologies in giving consideration to the following criteria:

- Bellatrix's technical expertise in the opportunity;
- the amount of risk capital required to secure or evaluate the investment opportunity;
- the potential return on the project, if successful;
- the likelihood of success; and
- risked return versus cost of capital.

In general, Bellatrix expects to continue to pursue a portfolio approach in developing a large number of opportunities with a balance of risk profiles and commodity exposure in an attempt to generate high levels of sustainable growth.

The Corporation continues to target areas and prospects that it believes could result in meaningful reserve and production additions. Bellatrix may, however, in its discretion, proceed with asset or corporate acquisitions or investments that do not conform to the guidelines discussed above based upon its consideration of the qualitative aspects of the subject properties, including risk profile, technical upside, reserve life and asset quality. In addition, Bellatrix may from time to time consider seeking joint venture partners, strategic investors or other business arrangements to help accelerate development of its properties.

Bellatrix's management team is comprised of a proven team of professional management in all key operational areas of the organization including a team experienced in providing organic growth through full cycle exploration, exploitation and development. See "*Directors and Officers*".

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices received for our oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and experienced a sharp and continued decline since 2014. Such prices are determined by supply and demand factors, including weather, general economic conditions, and actions taken by OPEC and other oil and gas producing countries, as well as conditions in other oil and natural gas regions. Any decline in oil and natural gas prices could have an adverse effect on our financial condition. We partially mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs. Additionally, we continually review our capital program and implement initiatives to adapt to such price changes.

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

See "*Risk Factors*".

Social and Environmental Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the requirements established for the oil and gas industry. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with such requirements.

A copy of Bellatrix's 2016 Corporate Responsibility Report that addresses Bellatrix's policies and commitment to health and safety, environment, people and culture, and community and stakeholder engagement matters is available on Bellatrix's website at www.bellatrixexploration.com.

Competitive Conditions

The oil and natural gas industry is intensely competitive in all its phases. Bellatrix competes with numerous other participants in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. Bellatrix's competitors include resource companies which have greater financial resources, staff and facilities than those of Bellatrix. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery. Bellatrix believes that its competitive position is equivalent to that of other oil and gas issuers of similar size and at a similar stage of development.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "**Statement**") is dated March 7, 2017. The effective date of the Statement is December 31, 2016.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by InSite with an effective date of December 31, 2016. The Reserves Data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs. The Reserves Data conforms with the requirements of NI 51-101. We engaged InSite to provide an evaluation of proved and proved plus probable reserves. No attempt was made to evaluate possible reserves. All of our reserves are in Canada in the provinces of Alberta, British Columbia and Saskatchewan. Field inspections were not conducted.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by the Corporation's independent qualified reserves evaluator in Form 51-101F2 are attached as Appendix "A" and Appendix "B" respectively, hereto.

It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquid reserves may be greater than or less than the estimates provided herein.

Reserves Data (Forecast Prices and Costs)

**SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS**

Reserves Category	Light And Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas[1]		Natural Gas Liquids	
	Gross (Mbbls)	Net (Mbbls)	Gross (Mbbls)	Net (Mbbls)	Gross (MMcf)	Net (MMcf)	Gross (Mbbls)	Net (Mbbls)
Proved Developed Producing	1,472.5	1,316,6	25.4	24.0	271,384.2	239,688.0	13,593.0	10,054.5
Proved Developed Non-Producing	19.5	16.4	0	0	4,817.1	4,157.0	192.5	136.9
Proved Undeveloped	2,651.3	2,153.5	108.9	94.6	431,439.8	374,654.0	22,397.3	18,135.0
Total Proved	4,143.2	3,486.4	134.3	118.6	707,641.0	618,498.9	36,182.8	28,326.4
Probable	2,189.6	1,738.2	207.8	177.1	310,819.3	264,769.8	15,938.6	12,282.3
Total Proved Plus Probable	6,332.8	5,224.6	342.1	295.7	1,018,460.3	883,268.7	52,121.4	40,608.7

Note:

(1) Includes minor amounts of natural gas from coal bed methane, shale gas reserves and solution gas. Coal bed methane, shale gas and solution gas reserves represent an immaterial portion of the Corporation's natural gas reserves.

Net Present Values of Future Net Revenue

Reserves Category	Before Income Taxes Discounted At (%/year)					After Income Taxes Discounted at (%/year)					Unit Value Before Income Tax Discounted at 10% Year[1]	
	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)	0 ($000s)	5 ($000s)	10 ($000s)	15 ($000s)	20 ($000s)	($/BOE)	($/ Mcfe)
Proved Developed Producing	849,040	628,251	498,861	415,913	358,881	849,040	628,251	498,861	415,913	358,881	9.72	1.62
Proved Developed Non–Producing	12,396	9,069	6,998	5,616	4,641	12,396	9,069	6,998	5,616	4,641	8.27	1.38
Proved Undeveloped	1,382,559	818,585	524,514	354,819	249,188	1,167,808	718,637	474,073	327,704	233,860	6.33	1.06
Total Proved	2,243,995	1,455,905	1,030,372	776,348	612,710	2,029,244	1,355,957	979,932	749,233	597,382	7.63	1.27
Probable	1,434,955	813,236	525,182	369,131	274,666	1,050,606	603,882	397,441	285,361	217,008	9.00	1.50
Total Proved Plus Probable	3,678,950	2,269,141	1,555,554	1,145,479	887,376	3,079,849	1,959,839	1,377,373	1,034,594	814,390	8.05	1.34

Note:

(1) Unit values are based upon net reserves.

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

Reserves Category	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Capital Development Costs ($000s)	Abandonment and Reclamation Costs ($000s)	Future Net Revenue Before Income Taxes ($000s)	Income Tax ($000s)	Future Net Revenue After Income Taxes ($000s)
Proved Reserves	5,332,166.7	688,812.3	1,685,089.8	684,674.5	29,595.6	2,243,994.5	214,750.8	2,029,243.7
Proved Plus Probable	8,068,988.6	1,098,644.4	2,308,453.3	945,052.1	37,889.1	3,678,949.7	599,100.2	3,079,849.4

FUTURE NET REVENUE
BY PRODUCTION GROUP(1)
AS OF DECEMBER 31, 2016
FORECAST PRICES AND COSTS

Reserves Category	Production Group(1)	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value(2) Before Income Tax (discounted at 10%/year)
Proved	Light and Medium Crude Oil (including solution gas and other by–products)	145,371.6	$7.20/BOE
	Heavy Crude Oil (including solution gas and other by-products)	1,183.4	$9.98/BOE
	Conventional Natural Gas (including by–products but excluding solution gas from oil wells)(3)	883,817.3	$7.71/BOE
	Natural Gas Liquids	-	
	Total	1,030,372.4	
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	213,083.6	$7.15/BOE
	Heavy Crude Oil (including solution gas and other by-products)	3,347.2	$11.32/BOE
	Conventional Natural Gas (including by–products but excluding solution gas from oil wells)(3)	1,339,123.6	$8.20/BOE
	Natural Gas Liquids	-	
	Total	1,555,554.4	

Notes:

(1) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
(2) Unit values are based on net reserves of primary product.
(3) Includes minor amounts of revenue and costs associated with natural gas from coal bed methane and shale gas reserves.

Notes to Reserves Data Tables:

1. Columns may not add due to rounding.

2. The crude oil, natural gas liquids and natural gas reserve estimates presented in the InSite Report are based on the definitions and guidelines contained in the COGE Handbook. A summary of those definitions are set forth below.

Reserve Categories

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

- Analysis of drilling, geological, geophysical and engineering data;
- The use of established technology; and
- Specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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.

Other criteria that must also be met for the categorization of reserves are provided in Section 5.5 of the COGE Handbook.

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

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

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

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

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

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are made). 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 quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in Section 5.5.3 of the COGE Handbook.

3. Well abandonment, reclamation and disconnect costs were estimated and included in the InSite Report at the individual entity level for all wells that were assigned reserves (including future wells to be drilled) and for dedicated facilities required to produce these reserves, for the purposes of estimating the Reserves Data. Allowance for salvage value was included. Abandonment and reclamation costs for wells with no assigned reserves and for non-dedicated gathering systems, batteries, plants and processing facilities were not included for the purposes of estimating the Reserves Data contained in the InSite Report. We use historical cost information on an area by area basis as the means for estimating the future abandonment and reclamation costs. When this information is not available, the estimate is determined with reference to appropriate regulatory standards and requirements.

4. The after-tax net present value of the Corporation's properties here reflects the tax burden on all of the properties of the Corporation taken as a whole. It does not consider the business-entity-level tax situation, or tax planning. It does not provide an estimate of the value at the level of the business entity, which may be significantly different. The financial statements and the management's discussion and analysis of the Corporation should be consulted for information at the level of the business entity. Furthermore, the tax methodology used assumes that all tax pools are utilized to the maximum depreciation rate as currently permitted.

5. Forecast Prices and Costs

The forecast cost and price assumptions are generally acceptable, in the opinion of InSite, as being a reasonable outlook of the future as at December 31, 2016.

The forecast cost and price assumptions include increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

The following tables set forth the benchmark reference prices, as at December 31, 2016, reflected in the Reserves Data. These price assumptions were provided to Bellatrix by InSite and were InSite's then current forecast at the effective date of the InSite Report.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	OIL: Canadian Light Sweet Crude 40° API ($Cdn/Bbl)	OIL: Western Canada Select 20.5° API ($Cdn/Bbl)	NATURAL GAS AECO Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS at Edmonton(1) ($Cdn/Bbl)	INFLATION RATES(2) %/Year	EXCHANGE RATE(3) ($US/$Cdn)
Forecast 2017	68.33	54.33	3.47	75.17	2.0	0.750
2018	72.32	58.32	3.42	79.55	2.0	0.775
2019	76.05	62.05	3.59	83.65	2.0	0.800
2020	79.54	65.54	3.93	87.50	2.0	0.825
2021	82.82	68.82	4.01	91.11	2.0	0.850
2022	88.60	74.60	4.17	97.46	2.0	0.850
2023	90.37	76.37	4.27	99.41	2.0	0.850
2024	92.18	78.18	4.43	101.39	2.0	0.850
2025	94.02	80.02	4.52	103.42	2.0	0.850
2026	95.90	81.90	4.61	105.49	2.0	0.850
Thereafter	+2.0%/yr	+2.3%/yr(4)	+2.0%/yr	+2.0%/yr		

Notes:

(1) Natural gas liquids is represented by pentanes plus price.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.
(4) Inflation rate is 2.3% until 2034 and 2.0% thereafter.

Weighted average historical prices realized by Bellatrix (before commodity price risk management contracts) for the year ended December 31, 2016, were $2.27/Mcf for natural gas, $48.41/Bbl for light and medium gravity crude oil and condensate, and $13.14/Bbl for natural gas liquids (excluding condensate).

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of our gross reserves as at December 31, 2015 compared to December 31, 2016 based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM CRUDE OIL Company Gross Proved (Mbbl)	Company Gross Probable (Mbbl)	Company Gross Proved Plus Probable (Mbbl)	HEAVY CRUDE OIL Company Gross Proved (Mbbl)	Company Gross Probable (Mbbl)	Company Gross Proved Plus Probable (Mbbl)
December 31, 2015(2)	11,596.1	5,534.0	17,130.1	213.2	230.2	443.4
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0
Infill Drilling	390.5	269.4	659.9	0.0	0.0	0.0
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	-67.7	-290.1	-357.8	-63.7	-22.6	-86.3
Acquisitions	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	-6,934.2	-3,413.5	-10,347.7	0.0	0.0	0.0
Economic Factors	-136.7	89.8	-46.9	-0.9	0.2	-0.7
Production	-704.8	0.0	-704.8	-14.3	0.0	-14.3
December 31, 2016(3)	4,143.2	2,189.6	6,332.8	134.3	207.8	342.1

FACTORS	NATURAL GAS LIQUIDS Company Gross Proved (Mbbl)	Company Gross Probable (Mbbl)	Company Gross Proved Plus Probable (Mbbl)	CONVENTIONAL NATURAL GAS[1] Company Gross Proved (MMcf)	Company Gross Probable (MMcf)	Company Gross Proved Plus Probable (MMcf)
December 31, 2015[2]	33,392.3	19,431.8	52,824.1	589,768.1	323,622.6	913,390.7
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions	0.0	0.0	0.0	0.0	0.0	0.0
Infill Drilling	7,776.8	1,931.7	9,708.5	151,697.2	42,973.2	194,670.4
Improved Recovery	0.0	0.0	0.0	0.0	0.0	0.0
Technical Revisions	1,750.9	-1,470.4	280.5	46,108.9	-30,877.9	15,231.0
Acquisitions	1,511.4	559.3	2,070.7	31,277.3	9,981.1	41,258.4
Dispositions	-5,143.6	-4,443.1	-9,586.7	-49,947.4	-34,640.8	-84,588.2
Economic Factors	-196.0	-70.7	-266.7	-4,852.5	-238.9	-5,091.4
Production	-2,909.0	0.0	-2,909.0	-56,410.6	0.0	-56,410.6
December 31, 2016[3]	36,182.8	15,938.6	52,121.4	707,641.0	310,819.3	1,018,460.3

Notes:

(1) Includes minor amounts of natural gas from coal bed methane and shale gas reserves.
(2) As evaluated by Sproule in a report dated March 10, 2016 and effective as of December 31, 2015 using an average of forecast prices and costs published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd.
(3) As evaluated by InSite in the InSite Report using the forecast prices and costs published by InSite.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following tables set forth the proved undeveloped gross reserves and the probable undeveloped gross reserves, each by product type, attributed to Bellatrix's assets for the years ended December 31, 2016, 2015 and 2014 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas[1] (MMcf)		NGLs (Mbbl)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
2014	796.5	7,866.9	0.0	108.9	33,762.0	356,650.0	1,549.6	17,508.0
2015	142.9	6,291.5	0.0	107.6	41,495.0	326,164.0	2,126.7	18,101.6

2016	375.9	2,651.3	0.0	108.9	92,750.8	431,439.8	4,825.6	22,397.3

Probable Undeveloped Reserves

Year	Light and Medium Crude Oil (Mbbl)		Heavy Crude Oil (Mbbl)		Conventional Natural Gas[1] (MMcf)		NGLs (Mbbl)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
2014	1,317.9	5,434.6	0.0	187.0	50,976.0	276,565.0	2,367.5	16,324.1
2015	109.1	4,216.2	0.0	200.0	39,428.0	254,565.0	2,058.6	15,469.3
2016	118.8	998.5	0.0	154.8	62,261.9	146,381.7	2,832.9	7,689.8

Note:

(1) Includes minor amount of natural gas from coal bed methane and shale gas reserves.

Proved Undeveloped Reserves

A total of 431,440 MMcf of natural gas, 2,760 Mbbl of oil and 22,397 Mbbl of NGLs were assigned as proved undeveloped reserves as at December 31, 2016, representing approximately 61% of our total proved reserves. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data. In estimating future net revenue, InSite reviewed Bellatrix's future development plans in order to estimate and deduct future development costs. Therefore the future development costs as set under "*Future Development Costs*" are consistent with Bellatrix's future development plans at year end. The capital associated with developing proved undeveloped reserves is expected to be spent between 2017 and 2022. With respect to capital development costs associated with proved undeveloped reserves in the InSite Report, approximately 52% of the capital is scheduled to be spent over the next three years and 96% is scheduled to be spent over the next five years.

The west central region of Alberta is a significant producing and development area for Bellatrix. Development drilling in both the proved and probable cases is anticipated for oil and gas in Brazeau, Ferrier and Strachan representing 88% of all assigned proven future development capital. The programs are staged in line with sound development practices and to exploit horizontal drilling and multi-fracturing completion opportunities.

Residual future development capital is assigned across various other properties operated by Bellatrix including Willesden Green, Baptiste and Pembina. The majority of this spending is also forecast for the next five years with minor work planned past this point, based on relief of existing wellbore constraints.

Although Bellatrix expects the development of its proved undeveloped reserves to be consistent with that set out above, current industry conditions and other uncertainties as discussed under "*Risk Factors*" herein could result in development of Bellatrix's proved undeveloped reserves on a different schedule than set out above. See also the discussion under "*Future Development Costs*" that references the Corporation's 2017 net capital budget.

Probable Undeveloped Reserves

A total of 246,861 MMcf of natural gas, 2,838 Mbbl of oil and 12,784 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2016, representing approximately 80% of our total probable reserves or 24% of total proved plus probable reserves.

The bulk of the probable undeveloped reserves assigned are associated with projects that have a proved reserves component. Probable reserves are attributed in addition to provide reserves in these cases according to the definitions and guidelines of the COGE Handbook. There are also some projects assigned probable reserves that do not have a proven reserves component, as per the terms of the COGE Handbook.

As was the case with proved undeveloped reserves, the West Central Alberta region has significant probable undeveloped reserves. The expenditures required to develop the probable undeveloped reserves are scheduled in a staggered pattern from 2017 to 2022. With respect to capital development costs associated with probable undeveloped reserves in the InSite Report, approximately 36% of the capital is scheduled to be spent over the next three years and 98% is scheduled to be spent over the next five years. In scheduling future development capital, priority is given to projects with a proved component, as those projects have reduced risk and are easier to predict timing or serve to prove up further projects currently only assigned probable reserves.

Although Bellatrix expects the development of its probable undeveloped reserves to be consistent with that set out above, current industry conditions and other uncertainties discussed under "*Risk Factors*" herein could result in development of Bellatrix's probable undeveloped reserves on a different schedule than set out above. See also the discussion under "*Future Development Costs*" that references the Corporation's 2017 net capital budget.

Significant Factors or Uncertainties

While we do not anticipate any significant economic factors or uncertainties will affect any particular components of the reserves data, the reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control (see "*Risk Factors*").

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below:

Year	**Proved Reserves ($000s)**	**Proved Plus Probable Reserves ($000s)**
2017	60,699.6	68,019.6
2018	128,790.0	164,816.8
2019	168,950.2	219,876.8
2020	150,301.1	215,046.8
2021	149,489.1	246,148.5
Thereafter	26,444.5	31,143.6
Total: Undiscounted	684,674.5	945,052.1

The capital expenditure program developed for the reserves evaluation, including estimated future development costs, was developed based on using cash flow from operations and available credit facilities. Equity financing was also considered to fund operations. If cash flows are other than projected, capital expenditure levels may be adjusted. Our practice of continually monitoring spending opportunities in comparison to expected cash flow levels allows for adjustments to the capital program as required. In addition, depending on a number of factors including commodity prices, industry conditions and Bellatrix's financial and operating results, funds from credit facilities and equity financings may not be available on terms acceptable to the Corporation, which could also result in adjustments to the capital program as required. The expected costs of funding our capital expenditures have been built into the economics of the programs and the reserves evaluation.

As indicated under "*General Development of our Business – 2017 Capital Budget*", the Board set the net capital budget for 2017 at $105 million. It is expected that the 2017 net capital budget will meet the development schedule contemplated by the InSite Report.

Other Oil and Gas Information

Principal Properties

The following is a description of Bellatrix's principal oil and natural gas properties as at December 31, 2016. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2016 received by Bellatrix in respect of its working interest share before deduction of royalties and without including any royalty interest.

Ferrier

Located 35 kilometres northwest of Rocky Mountain House, Alberta, the Ferrier and Alder Flats areas produce natural gas and natural gas liquids from the Belly River, Cardium, Notikewin, Falher and Rock Creek zones at depths ranging from 1,800 to 2,700 metres. The Spirit River play comprises the Notikewin, Falher and Wilrich zones. Area production for 2016 averaged 26,958 BOE/d, comprised of 77% natural gas, 17% natural gas liquids and 6% light oil and condensate. The majority of oil production from the area is delivered to two batteries in which we have 61.18% and 100% working interests. Approximately 43**%** of Bellatrix's net gas volumes from the area are delivered to the Bellatrix Alder Flats Gas Plant with the remaining gas volumes from the area delivered to third party non-operated gas plants for processing, including two major gas processing facilities in the area in which the Corporation holds a minor working interest. Our land holdings in the area were 73,753 gross (53,802 net) acres of developed land and 24,504 gross (19,196 net) acres of undeveloped land as at December 31, 2016.

In 2016, Bellatrix operated the drilling of 18 gross (12.1 net) Spirit River horizontal liquids-rich gas wells, all of which were completed and tied in. In 2017, the Corporation plans to drill 15 gross (12.8 net) Spirit River horizontal gas wells. To date in 2017 at Ferrier, the Corporation has completed and placed 4 gross (3.7 net) wells on production, 1 gross (1.0 net) well is currently awaiting completion, and 1 gross (1.0 net) well is currently being drilled. An additional 2 gross (1.9 net) Spirit River horizontal gas wells are expected to be drilled and completed prior to the 2017 spring break-up. Bellatrix plans to drill 7 gross (5.2 net) Spirit River horizontal wells in the second half of 2017.

In addition, in 2017, the Corporation plans to drill 3 gross (3.0 net) Cardium horizontal gas and oil wells at Ferrier. To date in 2017, the Corporation has drilled 1 gross (1.0 net) well which is being prepared for completion and is currently drilling 1 gross (1.0 net) well, with the expectation that both will be completed and tied-in before the 2017 spring break-up.

Willesden Green

The Willesden Green area is located approximately 45 kilometres north of Rocky Mountain House, Alberta. This property produces oil and associated natural gas from the Cardium zone, liquids-rich natural gas from the Notikewin, Falher, Ellerslie, and Rock Creek formations at depths of 1,800 to 2,800 metres, and sweet dry natural gas from five shallower horizons, including the Paskapoo, Ardley, Horseshoe Canyon, Edmonton and Belly River at depths of 300 to 1,200 metres**.** Production from this area averaged 1,546 BOE/d for 2016, consisting of 75% natural gas, 15% natural gas liquids and 10% light oil and condensate. The majority of this production is operated. The Corporation owns and operates two compressor stations in the area with working interests ranging from 68.79% to 70%. Gas is delivered to two third party operated gas plants with one of which Bellatrix holds a minority interest for processing. The Corporation held 39,360 gross (20,808 net) acres of developed land and 9,920 gross (6,034 net) acres of undeveloped land as at December 31, 2016.

Bellatrix drilled and tied-in 1 gross (0.80 net) Spirit River horizontal liquids-rich gas well at Willesden Green in 2016. To date in 2017 at Willesden Green, the Corporation is currently drilling 1 gross (1.0 net) two mile Spirit River horizontal megabore well and expects to complete and tie-in such well prior to the 2017 spring break-up. Bellatrix plans to drill and complete an additional 3 gross (1.3 net) Spirit River horizontal wells in the second half of 2017.

Greater Pembina

Pembina is located about 25 kilometres west of Drayton Valley, Alberta. Significant oil reserves occur in the Cardium zone at a depth of 1,800 metres and, in addition, there is liquids-rich natural gas potential in the Mannville and Jurassic zones at depths of approximately 2,150 to 2,500 metres. Production from this area averaged 1,423 BOE/d for 2016, consisting of 39% natural gas, 11% natural gas liquids and 50% light oil and condensate.[1] The Corporation held 41,699 gross (22,243 net) acres of developed land and 20,492 gross (10,203 net) acres of undeveloped land as at December 31, 2016.

In 2016, Bellatrix elected not to participate and to go into a penalty position on one Ellerslie test well in the West Pembina area. The Corporation plans to participate in an expected 4 to 5 gross (1.3 to 1.8 net) non-operated Ellerslie horizontal wells in the West Pembina area in 2017, with the expectation that it will participate in 2 gross (0.8 net) Ellerslie horizontal test wells in the first quarter of 2017.

Strachan

Strachan is located approximately 12 kilometres south of Rocky Mountain House, Alberta. The area aligns well with the Corporation's focus on the light oil and liquids rich natural gas fairway in the Alberta Deep Basin. Historically, the area had been the focus of vertical drilling for oil and gas resources in the Cretaceous units; however, the area has experienced a rejuvenation of development activity with the onset of horizontal well development.

The Strachan property produces oil, natural gas and associated natural gas liquids from the Cardium formation from depths of 2,000 and 2,700 meters. Production from this property averaged 2,191 BOE/d for 2016, consisting of 16% light oil and condensate, 67% natural gas and 17% natural gas liquids. As at December 31, 2016, the Corporation owned and operated four facilities and had a 100% working interest in two compressor stations and a 50.25% working interest and 64.75% working interest in two other compressor stations. All gas production volumes are delivered to a third party non-operated gas plant for processing. Bellatrix held 21,110 gross (14,236 net) acres of developed land and 20,834 gross (16,345 net) acres of undeveloped land as at December 31, 2016.

Bellatrix did not operate or participate in the drilling of any Cardium or Ellerslie horizontal wells at Strachan in 2016. Bellatrix does not plan to drill any Cardium or Ellerslie horizontal wells at Strachan in 2017.

Oil and Natural Gas Wells

The following table sets forth the number and status of oil wells and gas wells in which we have a working interest as at December 31, 2016.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	216	124	80	26	922	479	325	221
Saskatchewan	4	1	0	0	1	1	33	32
British Columbia	0	0	1	0.4	5	0.6	20	9
Total	220	125	81	26.4	928	480	378	262

[1] The calculation of average daily production for the Greater Pembina area has excluded, from and after the date of closing of the Pembina Cardium Transaction (November 7, 2016), the production associated with such sold assets. See: "*General Development of our Business*"

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2016.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	402,145.09	244,828.46	189,003.84	138,608.13	591,148.93	383,436.59
British Columbia	8,132.05	2,108.30	85,992.45	33,862.84	94,124.50	35,971.14
Saskatchewan	13,326.90	12,719.89	8,005.19	7,732.27	21,332.09	20,452.16
Total	**423,604.04**	**259,656.65**	**283,001.48**	**180,203.24**	**706,605.52**	**439,859.89**

Note:

(1) May not add due to rounding.

Bellatrix does not expect any material expiries in its core land holdings in 2017.

Development of Bellatrix properties with no attributable reserves are subject to current industry conditions and uncertainties as indicated under "*Risk Factors*" herein. In addition, we expect that funding of development operations on such properties will be evaluated in the context of our total capital requirements having regard to rates of return, the likelihood of success and risked return versus cost of capital, and availability and reliability of methods of hydrocarbon delivery.

Forward Contracts and Marketing

Our commodity marketing strategy is to sell production in the spot market, complemented from time to time by price risk management instruments.

We periodically hedge the price on a portion of our crude oil, natural gas liquids and natural gas production. We hedged an average of 18% of total crude oil and natural gas liquids production and an average of 58% of total natural gas production during the twelve months ended December 31, 2016. The following provides details of the commodity price risk management arrangements outstanding as at December 31, 2016 and as of the date hereof.

As at December 31, 2016, the Corporation had entered into commodity price risk management arrangements as follows:

Type	**Period**	**Volume**	**Price**	**Index**
Natural Gas Fixed	January 1, 2016 to December 31, 2017	10,000 GJ/d	$3.00 CDN	AECO 5A
Natural Gas Fixed	January 1, 2016 to December 31, 2017	10,000 GJ/d	$3.00 CDN	AECO 7A
Natural Gas Fixed	January 1, 2016 to December 31, 2017	10,000 GJ/d	$3.00 CDN	AECO 5A
Natural Gas Fixed	January 1, 2016 to December 31, 2017	20,000 GJ/d	$3.00 CDN	AECO 5A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	4,220 GJ/d	$2.70 CDN	AECO 5A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	4,000 GJ/d	$2.74 CDN	AECO 5A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	4,000 GJ/d	$2.70 CDN	AECO 7A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	12,500 GJ/d	$2.898 CDN	AECO 5A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	10,000 GJ/d	$2.88 CDN	AECO 7A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	5,275 GJ/d	$2.91 CDN	AECO 5A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	6,000 GJ/d	$2.90 CDN	AECO 7A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	10,000 GJ/d	$2.90 CDN	AECO 7A
Natural Gas Fixed	January 1, 2017 to December 31, 2017	10,000 GJ/d	$3.03 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.69 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.70 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.715 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.705 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.700 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.700 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.700 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.720 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	10,000 GJ/d	$2.755 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	10,000 GJ/d	$2.750 CDN	AECO 5A

Subsequent to December 31, 2016, the Corporation has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price	Index
Propane Swap	February 1, 2017 to December 31, 2017	500 bbl/d	50% of NYMEX WTI USD	Conway
Propane Swap	February 1, 2017 to December 31, 2017	1,000 bbl/d	51% of NYMEX WTI USD	Conway
Propane Swap	January 1, 2018 to December 31, 2018	500 bbl/d	47% of NYMEX WTI USD	Conway
Propane Swap	January 1, 2018 to December 31, 2018	500 bbl/d	47% of NYMEX WTI USD	Conway
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.525 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.605 CDN	AECO 5A
Natural Gas Fixed	January 1, 2018 to December 31, 2018	5,000 GJ/d	$2.620 CDN	AECO 5A

Tax Horizon

The Corporation does not expect to pay current income tax for the 2016 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not be taxable in 2017. The Corporation does not expect to pay current taxes until 2018 or beyond. This expectation will be impacted by, among other factors, production volumes, commodity prices, foreign exchange rates, operating costs, interest rates, changes in tax laws and Bellatrix's other business activities. Changes in these factors from estimates used by Bellatrix could result in the Corporation paying income taxes earlier than expected.

Capital Expenditures

The following table summarizes capital expenditures (excludes non-cash expenditures relating to decommissioning liabilities, capitalized unit based compensation and corporate acquisitions) related to our assets and activities for the year ended December 31, 2016:

	$000's
Property acquisition costs	2,626
Proved properties	(9)
Undeveloped properties	2,635
Exploration costs	336
Development costs	75,689
Dispositions	(299,058)
Corporate Assets	230
Total	(220,177)

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells in which Bellatrix has an interest that were drilled during the year ended December 31, 2016.

	Exploratory Wells		Development Wells	
	Gross	Net	Gross	Net
Light and Medium Crude Oil	-	-	0	0
Conventional Natural Gas	1	0.8	18	12.14
Heavy Crude Oil	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	1	0.8	18	12.14

For additional details on the exploration and development activities during 2016, see "*Statement of Reserves Data and Other Oil and Gas Information – Other Oil and Gas Information – Principal Properties*".

Production Estimates

The following table sets out the volume of our gross production estimated for the year ended December 31, 2017, which is reflected in the estimate of gross proved reserves and gross proved plus probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*" above.

Reserves Category	**Light And Medium Crude Oil (Bbls/d)**	**Heavy Crude Oil (Bbls/d)**	**Conventional Natural Gas[(1)] (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**Total (BOE/d)**
Total Proved	627	32	140,090	6,856	30,862
Total Proved Plus Probable	642	34	151,951	7,432	33,433

Note:

(1) Includes minor amounts of coal bed methane and shale gas production.

The Ferrier property in the west central area of Alberta accounts for 24,594 BOE/d, or 74% of the estimated total production on a proved plus probable basis for the year ended December 31, 2017, which is reflected in the estimate of gross proved reserves and gross proved plus probable reserves disclosed in the tables contained under "*Disclosure of Reserves Data*" above.

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback, before hedging, associated with our assets for the periods indicated below:

	Quarter Ended			
	2016			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d) [(2)]	2,798	3,256	3,641	3,981
Conventional Natural Gas (Mcf/d)[(3)]	137,372	148,539	164,699	167,455
NGLs (Bbls/d) [(4)]	6,195	6,396	6,909	6,577
Combined (BOE/d)	31,888	34,409	38,000	38,467

	Quarter Ended			
	2016			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Price Received				
Light and Medium Crude Oil ($/Bbl) (2)	58.12	50.08	49.32	39.33
Conventional Natural Gas ($/Mcf)(3)	3.29	2.47	1.50	1.98
NGLs ($/Bbl) (4)	18.87	10.53	13.05	10.35
Combined ($/BOE)	22.95	17.36	13.60	14.52
Royalties Paid				
Light and Medium Crude Oil ($/Bbl) (2)	10.67	9.44	7.77	7.41
Conventional Natural Gas ($/Mcf)(3)	0.16	(0.04)	(0.08)	(0.06)
NGLs ($/Bbl) (4)	5.21	2.72	3.72	2.60
Combined ($/BOE)	2.64	1.22	1.05	0.97
Operating Expenses				
Light and Medium Crude Oil ($/Bbl) (2)	9.57	6.91	7.87	7.68
Conventional Natural Gas ($/Mcf)(3)	1.78	1.48	1.42	1.22
NGLs ($/Bbl) (4)	10.67	8.88	8.53	7.33
Combined ($/BOE)	10.57	8.69	8.46	7.37

	Quarter Ended			
	2016			
	Dec. 31	Sept. 30	June 30	Mar. 31
Netback Received before Transportation				
Light and Medium Crude Oil ($/Bbl) (2)	37.87	33.72	33.68	24.24
Conventional Natural Gas ($/Mcf)(3)	1.35	1.03	0.16	0.83
NGLs ($/Bbl) (4)	2.98	(1.08)	0.81	0.42
Combined ($/BOE)	9.94	7.95	4.45	6.20
Transportation Costs				
Light and Medium Crude Oil ($/Bbl) (2)(5)	0.85	0.90	1.04	1.26
Conventional Natural Gas ($/Mcf)(3)	0.23	0.18	0.18	0.18
NGLs ($/Bbl) (4)	-	-	-	-
Combined ($/BOE)	1.07	0.86	0.87	0.92
Netback Received after Transportation (6)				
Light and Medium Crude Oil ($/Bbl) (2)	37.02	32.82	32.64	22.98
Conventional Natural Gas ($/Mcf)(3)	1.12	0.85	(0.02)	0.65
NGLs ($/Bbl) (4)	2.98	(1.08)	0.81	0.42
Combined ($/BOE)	8.87	7.09	3.58	6.50

Notes:

(1) Includes minor royalty volumes received but does not deduct royalty volumes paid.
(2) Includes condensate production and minor amounts of heavy oil production.
(3) Includes minor amounts of coal bed methane and shale gas production. Negative values reflect gas cost allowance credits from the Alberta government.
(4) NGL pricing excludes condensate.
(5) Fourth quarter transportation costs for Light and Medium Crude Oil reflect adjustments for certain credits received for reductions in trucking expenses.
(6) Netbacks are calculated by subtracting royalties, operating and transportation costs from revenues. Netbacks do not include other income.

The following table indicates average daily company share production from important fields in respect of our assets for the year ended December 31, 2016. Company share production includes minor royalty volumes received but does not deduct royalty volumes paid.

	Light and Medium Crude Oil (Bbls/d) (1)	Condensate (Bbls/d)	Conventional Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d) (2)
West Central Alberta Region					
Ferrier	343	1,187	124,373	4,700	26,958
Harmattan(3)	609	13	7,542	1,056	2,935
Strachan	177	160	8,867	377	2,191
Greater Pembina(4)	683	28	3,365	151	1,423
Willesden Green	96	62	6,931	233	1,546
Total West Central Alberta Region	1,908	1,450	151,077	6,516	35,053
Other Properties	58	1	3,376	2	624
TOTALS	1,966	1,451	154,453	6,518	35,677

Note:

(1) Includes minor amounts of heavy oil production.
(2) May not add due to rounding.
(3) In 2016, the Corporation disposed of all of its assets in the Harmattan area pursuant to the Harmattan Transaction. See: "*General Development of our Business*".
(4) In 2016, the Corporation disposed of certain assets in the Greater Pembina area pursuant to the Pembina Cardium Transaction. See: "*General Development of our Business*".

For the year ended December 31, 2016, approximately 28% of gross revenue from our assets was derived from crude oil and natural gas liquids production and 72% was derived from natural gas production.

DIVIDENDS

Bellatrix has not paid any dividends on the outstanding Common Shares. The Board has determined not to pay any dividends on the Common Shares at the present time. Any future decision to pay dividends, including the actual timing, payment and amount of dividends, if any, will be made by the Board based upon, among other things, the cash flow, results of operations and financial conditions of Bellatrix, the need for funds to finance ongoing operations and other business considerations as the Board considers relevant.

RATINGS

The following table outlines the ratings assigned to the Corporation and the Senior Notes as of the date hereof:

Rating Agency	Corporate Rating	Senior Notes Rating	Trend/Outlook
Standard and Poor's Ratings Service ("**S&P**")	**B**	**B**	**Stable**
Moody's Investor Service, Inc. ("**Moody's**")	**Caa1**	**Caa2**	**Negative**

The corporate rating addresses the overall credit strength of the Corporation, without consideration for security or ranking of security or ranking of any particular indebtedness. The long-term credit rating on the Senior Notes is intended by the ratings agencies to provide an independent indication of the risk that a borrower will not fulfill its full obligations with respect to a given type and/or series of securities in a timely manner with respect to both interest and principal commitments.

The credit ratings assigned by the rating agencies are not recommendations to purchase, hold or sell the Senior Notes or the Corporation's other securities (including the Common Shares) and may be subject to revision or withdrawal at any time by the credit rating organization.

A definition of the categories of each rating has been obtained from the respective rating organization's website and is outlined below:

S&P's credit ratings are on a long-term rating scale that ranges from AAA to D, which represents the highest to lowest opinions of creditworthiness. 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). A rating of B by S&P is within the sixth highest of ten categories and is regarded as having a significant speculative characteristics. According to S&P, an obligor rated "B" is more vulnerable than the obligors rated "BB" to adverse business, financial and economic conditions, but currently has the capacity to meet its financial commitments. An obligation rated "CCC" is currently vulnerable to nonpayment, and is dependent upon favorable business, financial, and economic conditions for the obligor to meet its financial commitment on the obligation. A rating of "CCC+" is considered to be less vulnerable than "CCC".

Moody's credit ratings are on a long-term rating scale that ranges from Aaa to C, which represents the highest to lowest opinions of creditworthiness. Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aa through Caa. The modifier 1 indicates that the security ranks in the higher end of its generic rating category; the modifier 2 indicates a mid-range ranking; and the modifier 3 indicates a ranking in the lower end of its generic rating category. In addition, Moody's may add a rating outlook of "positive", "negative", "stable" or "developing" which assess the likely direction of an issuers rating over the medium term. A rating of "Caa" by Moody's is within the seventh highest of nine categories. According to Moody's, obligations rated "Caa" are judged to be speculative of poor standing and are subject to very high credit risk.

Bellatrix has paid customary fees to S&P and Moody's in connection with the above-mentioned ratings. Bellatrix did not make any payments to S&P and Moody's in respect of any other service provided to Bellatrix by S&P and Moody's during the last two years.

DESCRIPTION OF SHARE CAPITAL

Bellatrix is authorized to issue an unlimited number of Common Shares and up to 95,978,621 Preferred Shares, issuable in series. There are currently no issued and outstanding Preferred Shares of any series. The following is a description of the material provisions attaching to Bellatrix's share capital.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of Common Shares are entitled to receive notice of, to attend and to vote at all meetings of shareholders and are entitled to one vote per Common Share held at such meetings, except meetings of holders of another class or one or more series of another class of shares who are entitled to vote separately as a class at such meeting.

Dividends: Subject to the preferences accorded holders of any shares of Bellatrix ranking senior to the Common Shares from time to time with respect to the payment of dividends, holders of Common Shares are entitled to receive if, as and when declared by the Board, such dividends or other distributions as may be declared thereon by the Board from time to time.

Ranking: In the event of any voluntary or involuntary liquidation, dissolution or winding-up of Bellatrix or any other distribution of Bellatrix's assets among its shareholders for the purpose of winding-up its affairs, holders of Common Shares are entitled, subject to the preferences accorded to holders of any shares of Bellatrix ranking senior to the Common Shares from time to time with respect to payment on a Distribution, to share equally, share for share, in the remaining property of Bellatrix.

Preferred Shares

The Preferred Shares may at any time and from time to time be issued in one or more series, where the Board will be authorized to fix the number of shares of each series, subject to the limitation on the number of Preferred Shares to be issued as described above, and to determine for each series, subject to the terms and conditions set out below, the designation, rights, privileges, restrictions and conditions, including dividend rates, redemption prices, conversion rights and other matters. The Preferred Shares have the following rights, privileges, restrictions and conditions:

Voting Rights: Holders of any series of Preferred Shares will not be entitled (except as otherwise provided by law and except for meetings of the holders of Preferred Shares or a series thereof) to receive notice of, attend at, or vote at any meeting of shareholders of Bellatrix, unless the Board determines otherwise, in which case voting rights will only be provided in circumstances where Bellatrix has failed to pay a certain number of dividends on such series of Preferred Shares, which determination and number of dividends and any other terms in respect of such voting rights, will be determined by the Board and set out in the designations, rights, privileges, restrictions and conditions of such series of Preferred Shares.

Dividends: The holders of each series of Preferred Shares will be entitled to receive dividends (which may be cumulative or non-cumulative and variable or fixed) as and when declared by the Board on such series of Preferred Shares.

Ranking: Each series of Preferred Shares will be entitled to priority over the Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of Bellatrix, whether voluntary or involuntary, and any other distribution of the assets of Bellatrix among its shareholders for the purpose of winding-up its affairs. The Preferred Shares of any series may also be given such other preferences, not inconsistent with the provisions hereof, over the Common Shares and any other shares of Bellatrix ranking junior to the Preferred Shares, as may be determined by the Board.

Parity among Series: Each series of Preferred Shares will rank on a parity with every other series of Preferred Shares with respect to priority in the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, and any other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs.

Participation upon Liquidation, Dissolution or Winding Up: In the event of the liquidation, dissolution or winding up of the Corporation or other distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs, the holders of the Preferred Shares will be entitled to receive from the assets of the Corporation any cumulative dividends, whether or not declared, or declared non-cumulative dividends or amounts payable on a return of capital which are not paid in full in respect of any Preferred Shares, before any amount is paid or any assets of the Corporation are distributed to the holders of any Common Shares or shares of any other class ranking junior to the Preferred Shares. After payment to the holders of the Preferred Shares of the amount so payable to them as above provided they will not be entitled to share in any further distribution of assets of the Corporation among its shareholders for the purpose of winding up its affairs.

Conversion: The Preferred Shares may be convertible into Common Shares or another series of Preferred Shares provided that the maximum number of Common Shares that may be issuable upon conversion of all series of Preferred Shares is limited to 38,391,448 Common Shares, which is equal to 20% of the number of Common Shares issued and outstanding as of April 10, 2015.

Redemption: Each series of Preferred Shares may be redeemable by the Corporation on such terms as may be determined by the Board.

MARKET FOR SECURITIES

Common Shares

The Common Shares are listed and trade on the TSX and NYSE and trade under the symbol "BXE". The following tables set forth the price range and trading volume of the Common Shares on the TSX and NYSE for the periods indicated.

TSX

Period	High ($)	Low ($)	Volume
2016			
January	1.84	1.11	31,764,943

February	1.74	1.18	32,415,003
March	1.99	1.18	62,519,680
April	1.49	1.17	43,602,371
May	1.43	1.22	57,349,907
June	1.68	1.18	63,316,462
July	1.44	1.10	47,305,944
August	1.19	0.96	35,338,314
September	1.28	0.99	70,639,626
October	1.29	1.05	45,268,494
November	1.22	0.96	44,665,215
December	1.40	1.08	38,683,509
2017			
January	1.37	1.05	22,102,072
February	1.11	0.97	18,606,028
March (1 – 14)	1.14	1.00	7,918,467

NYSE

Period	High (US$)	Low (US$)	Volume
2016			
January	1.31	0.75	33,792,168
February	1.26	0.85	28,533,148
March	1.48	0.90	60,478,498
April	1.19	0.90	14,755,500
May	1.13	0.93	11,230,907
June	1.30	0.90	20,563,507
July	1.11	0.84	15,268,447
August	0.90	0.75	12,826,291
September	0.98	0.75	11,253,416
October	0.96	0.79	7,879,869
November	0.92	0.72	10,270,351
December	1.07	0.80	14,877,690

2017			
January	1.03	0.82	10,395,019
February	0.86	0.74	9,238,289
March (1 – 14)	0.85	0.75	4,171,829

Convertible Debentures

The Convertible Debentures are listed and trade on the TSX and trade under the symbol "BXE.DB". The following tables set forth the price range and trading volume of the Convertible Debentures on the TSX for the periods indicated.

TSX

Period	High ($)	Low ($)	Volume
2016			
August (9-31)[(1)]	98.00	87.00	12,535,000
September	101.00	94.50	8,358,000
October	101.02	98.50	2,766,000
November	99.00	96.50	1,601,000
December	106.00	98.00	2,004,000
2017			
January	104.99	100.50	1,616,000
February	101.25	99.99	3,448,000
March (1 – 14)	102.00	100.00	458,000

Note:

(1) The Convertible Debentures commenced trading on the TSX on August 9, 2017 on completion of the Convertible Debenture and Subscription Receipt Offering.

PRIOR SALES

Other than options to purchase Common Shares granted under the share option plan of the Corporation and restricted awards and performance awards granted under the incentive award plan of the Corporation, Bellatrix did not sell or issue any securities of the Corporation that are not listed or quoted on any stock exchange or other marketplace. The following table sets out details of all options under the share option plan of the Corporation and restricted awards and performance awards granted under the incentive award plan of the Corporation during the year ended December 31, 2016:

Date	Type of Security	Number of Securities	Price per Security ($)[(1)]
August 19, 2016	Performance Awards	725,426	$1.02(1)
August 19, 2016	Restricted Awards	1,333,860	$1.02[(1)]
August 19, 2016	Options	2,909,100	$1.02[(2)]
November 30, 2016	Restricted Awards	90,000	$1.04[(1)]

Notes:

(1) The value listed as the "price per security" represents the volume weighted average trading price of the Common Shares on the TSX for the five trading days prior to the grant of such restricted awards or performance awards as applicable.

(2) The value listed as the "price per security" represents the exercise price of the options granted.

Additional information relating to the Corporation's share option plan and incentive award plan will be available in the management information circular for the Corporation's upcoming annual meeting of shareholders of the Corporation, which is currently scheduled to be held on May 17, 2017.

ESCROWED SECURITIES

There are no securities of the Corporation currently held in escrow.

BORROWINGS

Credit Facilities

The Corporation maintains extendible revolving reserves-based credit facilities with a syndicate of lenders (the "**Credit Facilities**"). The Credit Facilities are available on a fully revolving basis until October 1, 2017, do not require any mandatory principal payments prior to maturity, and can be further extended beyond October 2017 with the consent of the lenders. The Credit Facilities are available to finance Bellatrix's ongoing capital expenditures, working capital requirements and for general corporate purposes. The available Credit Facilities and related borrowing base are subject to semi-annual reviews in May and November of each year. The semi-annual borrowing base review is at the sole discretion of the lenders taking into consideration the estimated value of the Corporation's oil and natural gas properties in accordance with the lenders' customary practices for oil and gas loans. On July 18, 2016, the Corporation announced that the syndicate of lenders had completed its semi-annual review of the borrowing base and the renewal of its syndicated credit facilities and approved Bellatrix's request for a revised borrowing base and Credit Facilities of $365 million (the semi-annual redetermination was initially scheduled to be completed in May of 2016, but was deferred to July 2016). In the Corporation's semi-annual borrowing base review in November 2016, the Corporation and its lenders agreed to reduce the borrowing base and Credit Facilities to $130 million. As at December 31, 2016, following the closing of the Harmattan Transaction, and as at the date hereof, the borrowing base of the Credit Facilities consists of a $100 million syndicated facility provided by nine financial institutions.

Amounts borrowed under the Credit Facilities bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rate, CDOR rate or LIBOR margin rate, plus between 0.8% and 4.75%, depending on the type of borrowing and the Corporation's Senior Debt to EBITDA ratio. A standby fee is charged of between 0.405% to 1.06875% on the undrawn portion of the Credit Facilities, depending on the Corporation's Senior Debt to EBITDA ratio. The Credit Facilities are secured by a $1 billion debenture containing a first ranking charge and security interest. The Corporation has provided a negative pledge and undertaking to provide fixed charges over its properties in certain circumstances. The amount available under the Credit Facilities is not to exceed the borrowing base, which is currently $100 million. At December 31, 2016 the Corporation had $19.1 million outstanding at a weighted average interest rate of 4.45%. The borrowing base will be subject to re-determination on or before May 31 and November 30 in each year prior to the maturity of the Credit Facilities, with the next semi-annual re-determination occurring on or before May 31, 2017.

The Credit Facilities contain market standard terms and conditions, and include, for instance, restrictions on asset dispositions and hedging. Generally, dispositions of properties to which the Corporation is given lending value in the determination of the borrowing base require lender approval if the value attributed to all properties sold in a fiscal year exceeds 5% of the borrowing base in effect at the time of such disposition. In addition, asset dispositions are generally not permitted unless there would be no borrowing base shortfall as a result of such properties being sold. Hedging transactions must not be done for speculative purposes. The aggregate amount hedged under all oil and gas commodity swaps cannot exceed 70% of the Corporation's average daily sales volume for the first year of a rolling 3 year period, 60% for the second year of such period or 50% for the third year of such period, with the average daily sales volume being based on our production for the previous fiscal quarter. The term of any commodity swap cannot exceed 3 years. The aggregate amount hedged under all interest rate swaps designed to hedge against fluctuations in interest rates of unsecured note debt, including the Senior Notes, cannot exceed the outstanding principal amount of the applicable unsecured note debt and such swaps cannot have a term exceeding the remaining term of the unsecured note debt. For interest rate swaps unrelated to any unsecured note debt, the aggregate amount hedged cannot exceed 60% of the amount of the commitment under the Credit Facilities and such swaps cannot exceed a term of 3 years. The aggregate amount hedged under all exchange rate swaps designed to hedge against fluctuations of foreign exchange rates of unsecured note debt cannot exceed the outstanding principal amount of the applicable unsecured note debt or have a term exceeding the remaining term of the applicable unsecured note debt. For exchange rate swaps unrelated to any unsecured note debt, the aggregate amount hedged cannot exceed 60% of Bellatrix's U.S. dollar revenue over the previous 3 months and such swaps cannot exceed a term of 3 years.

The Credit Facilities are subject to a single financial covenant, which was met at December 31, 2016. The financial covenant in the Credit Facilities provides that the Corporation must maintain a consolidated Senior Debt to consolidated EBITDA ratio: (i) of not greater than 3.5 to 1 for each of the fiscal quarters up to and including the fiscal quarter ending March 31, 2017 (without adjustment thereto upon the consummation of a material acquisition), and (ii) of not greater than 3.0 to 1 for the fiscal quarter ending June 30, 2017 and all periods thereafter, except upon a consummation of a material acquisition which results in the Corporation being permitted for a period extending to and including the end of the second full fiscal quarter of the Corporation following the fiscal quarter in which the applicable material acquisition is completed, to hold a consolidated Senior Debt to consolidated EBITDA ratio of not greater than 3.5 to 1. The Corporation calculates its financial covenant quarterly. The calculation for the financial covenant is based on specific definitions that are not in accordance with International Financial Reporting Standards and cannot be readily replicated by referring to the Corporation's consolidated financial statements.

For a complete description of the terms of the Credit Facilities, copies of the agreement governing the Credit Facilities and all amendments thereto, have been filed on www.sedar.com and www.sec.gov under the Corporation's SEDAR and EDGAR profiles, respectively.

Senior Notes

The Senior Notes are governed by the Senior Note Indenture and bear interest at 8.500% per annum, payable semi-annually in arrears on May 15 and November 15 of each year. The Senior Notes are unsecured and are effectively subordinated to the Credit Facilities to the extent of the value of the collateral. The Senior Notes mature on May 15, 2020. The Senior Notes may be redeemed at the Corporation's option as follows:

(a) prior to May 15, 2017, the Senior Notes may be redeemed in whole or in part at a price equal to the greater of: (i) 100% of the principal amount of the Senior Notes; and (ii) the sum of the present values of (A) the redemption price of the Senior Notes at 2017 (being 104.250%), and (B) the remaining scheduled payments of interest from the redemption date to May 15, 2017 (excluding accrued and unpaid interest as of the redemption date) discounted back to the redemption date on a semimanual basis (at the treasury rate plus 50 basis points) plus, in the case of both (A) and (B), accrued and unpaid interest, if any, to the redemption date;

(b) prior to May 15, 2017, the Corporation may on any one or more occasions redeem up to 35% of the principal amount of the Senior Notes with an amount of cash no greater than the net cash proceeds of one or more equity offerings at a redemption price equal to 108.500% of the principal amount thereof, plus accrued and unpaid interest, provided that (i) at least 65% of the aggregate principal amount of the Senior Notes issued on the issue date (excluding any Senior Notes held by the Corporation) remains outstanding after each such redemption, and (ii) the redemption occurs within 180 days after the closing of such equity offering;

(c) on or after May 15 of each of the following years, the Senior Notes may be redeemed in whole or in part at the following redemption prices (expressed as a percentage of the principal amount of the Senior Notes) plus accrued and unpaid interest: 2017 at 104.438%, 2018 at 102.125%, 2019 and thereafter at 100%; and

(d) at any time, upon not less than 30 nor more than 60 days' notice, in whole, but not in part at a redemption price equal to 100% of the principal amount of the Senior Notes to be redeemed, plus accrued but unpaid interest thereon, if the Corporation determines that it has or will become obligated to pay Additional Amounts (as defined in the Senior Note Indenture) because of a Change in Tax Law (as defined in the Senior Note Indenture).

If a Change of Control (as defined in the Senior Note Indenture) occurs, and unless an exemption described in the Senior Note Indenture applies, the holders of the Senior Notes can require the Corporation to repurchase their Senior

Notes at a price equal to 101% of the aggregate principal amount of the Notes together with accrued and unpaid interest thereon.

For a complete description of the terms of the Senior Notes, a copy of the Senior Note Indenture has been filed on www.sedar.com and www.sec.gov under the Corporation's SEDAR and EDGAR profiles, respectively.

Convertible Debentures

On August 9, 2016 the Corporation issued $50,000,000 principal amount of Convertible Debentures pursuant to the Convertible Debenture and Subscription Receipt Offering. The Convertible Debentures have a face value of $1,000 per Convertible Debenture and have a maturity date of September 30, 2021 (the "**Maturity Date**"). The Convertible Debentures will bear interest at an annual rate of 6.75% payable semi-annually in arrears, on September 30 and March 31 in each year. The payment of the principal and premium, if any, of, and interest on, the Convertible Debentures is subordinated in right of payment to the prior payment in full of all "Senior Indebtedness" (as such term is defined in the Debenture Indenture and which includes the Credit Facilities and Senior Notes). Convertible Debentures will rank equally with one another and will rank pari passu with all of the Corporation's other existing and future unsecured subordinated indebtedness to the extent subordinated on the same terms,

Each Convertible Debenture will be convertible into Common Shares at a conversion price of $1.62 per Common Share (the "**Conversion Price**") at the option of the holder thereof at any time prior to 5:00 p.m. (Calgary time) on the earlier of: (i) the last business day immediately preceding the Maturity Date; (ii) the last business day immediately preceding any date set for redemption, and (iii) if called for repurchase pursuant to a mandatory repurchase, on the business day immediately preceding the payment date, representing a conversion rate of approximately 617.2840 Common Shares per $1,000 principal amount of Convertible Debentures, subject to adjustment in accordance with the Debenture Indenture.

The Convertible Debentures are not redeemable by the Corporation before September 30, 2019. On and after September 30, 2019 and prior to September 30, 2020, the Convertible Debentures are redeemable at the Corporation's option, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption, if the weighted average trading price of the Common Shares for the specified period is not less than 125% of the Conversion Price. On and after September 30, 2020, the Convertible Debentures are redeemable at the Corporation's option, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior written notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest thereon, if any, up to but excluding the date set for redemption.

Upon the maturity or redemption of the Convertible Debentures, the Corporation may pay the outstanding principal of the Convertible Debentures in cash or may, at its option, on not greater than 60 days and not less than 40 days prior notice and subject to regulatory approval, elect to satisfy its obligations to repay all or a portion of the principal amount of the Convertible Debentures, which have matured or been redeemed, by issuing and delivering that number of Common Shares obtained by dividing the aggregate principal of the Convertible Debentures which have matured or redeemed by 95% of the weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date fixed for redemption or the Maturity Date, as the case may be. Any accrued and unpaid interest will be paid in cash.

Within 30 days following the occurrence of a "Change of Control" (as such term is defined in the Debenture Indenture), the Corporation will be required to make an offer (the "**Change of Control Purchase Offer**") in writing to purchase all of the Convertible Debentures then outstanding, at a price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. If 90% or more of the aggregate principal amount of the Convertible Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Corporation pursuant to the Change of Control Purchase Offer, the Corporation will have the right to redeem all the remaining Convertible Debentures at the same offer price.

In addition, if a Change of Control occurs in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting the Change of Control consists of cash (other than payment for fractional Common Shares or cash payments made in satisfaction of appraisal rights), equities, securities or other properties not traded or intended to be traded immediately following such transaction on a stock exchange, then during the period beginning 10 trading days after the anticipated date that such Change of Control becomes effective and ending 30 days after the Change of Control Purchase Offer is delivered, holders of the Convertible Debentures will be entitled to convert the Convertible Debentures at an adjusted conversion price which will be adjusted based on a formula dependent on the then current trading price and the remaining period up to but excluding September 30, 2020.

For a complete description of the terms of the Convertible Debentures, a copy of the Debenture Indenture has been filed on www.sedar.com and www.sec.gov under the Corporation's SEDAR and EDGAR profiles, respectively.

DIRECTORS AND OFFICERS

The following table sets forth the name, age (as at December 31, 2016), province or state and country of residence, date first elected as a director of Bellatrix where applicable and office held for each of the current (as at the date hereof) directors and officers of Bellatrix together with their principal occupations during the last five years. The directors of Bellatrix shall hold office until the next annual meeting of shareholders or until their respective successors have been duly elected or appointed.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[1]	Principal Occupation
Brent A. Eshleman, P. Eng. Calgary, Alberta, Canada Age: 52	President and Chief Executive Officer and Director	February 15, 2017	President and Chief Executive Officer of Bellatrix since February 15, 2017 and prior thereto was Interim President and Chief Executive Officer since November 25, 2016; prior thereto Chief Operating Officer since September 1, 2014 and Executive Vice-President since July 2012. From December 2004 to January 2012, Vice-President Engineering and Exploitation of Daylight Energy Ltd. From May 2000 to November 2004 Director, Northern Alberta of Calpine Canada. From May 1998 to April 2000, Manager Engineering of Ulster Petroleum Ltd.
Edward J. Brown, CPA, CA Calgary, Alberta, Canada Age: 61	Executive Vice-President, Finance and Chief Financial Officer	N/A	Executive Vice-President, Finance and Chief Financial Officer of Bellatrix since April 1, 2013 and prior thereto was Vice-President, Finance and Chief Financial Officer. From July 4, 2006 to November 1, 2009, Vice-President, Finance and Chief Financial Officer of True Energy Inc. (as administrator of True Energy Trust); prior thereto, from March 2005 to June 2006, Vice-President, Finance and Chief Financial Officer of Petrofund Energy Trust; from February 2002 to March 2005, senior financial officer of Duke Energy Field Services Canada.
Charles R. Kraus, Esq. Calgary, Alberta, Canada Age: 41	Executive Vice-President, General Counsel and Corporate Secretary	N/A	Executive Vice-President, General Counsel and Corporate Secretary of Bellatrix since March 15, 2017. Prior thereto, Vice-President, General Counsel and Corporate Secretary since September, 2014. Prior thereto, Vice-President, General Counsel and Corporate Secretary of Lone Pine Resources Inc. from 2011 to 2014. Prior thereto, Mr. Kraus was in private practice for 10 years, most recently with the Calgary office of Stikeman Elliott LLP.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director(1)	Principal Occupation
Garrett K. Ulmer, P. Eng. Calgary, Alberta, Canada Age: 46	Chief Operating Officer	N/A	Chief Operating Officer since March 15, 2017. Prior thereto, Vice-President, Engineering of Bellatrix since October 2011. Prior thereto, held roles of Production Engineer, Production Manager, and Manager of Exploitation and Acquisitions of Bellatrix, and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust), since January 2008.
Timothy A. Blair Cochrane, Alberta, Canada Age: 58	Vice-President, Land	N/A	Vice-President, Land of Bellatrix, and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust), since October 2009. Prior thereto, Vice-President, Land for Terra Energy Corp. from June 2004 to September 2009.
Chris D. Curry, CPA, CA Calgary, Alberta, Canada Age: 42	Vice-President and Controller	N/A	Vice-President and Controller of Bellatrix since May 2014. Prior thereto, Director Finance and Corporate Development at Native American Resource Partners since September 2011. Prior thereto, held progressively senior finance roles over the previous 15 years at NuVista Energy Ltd., Enerplus Resources Fund and Precision Drilling Corporation.
Leanne K. Gress-Blue, CPA, CA Calgary, Alberta, Canada Age: 48	Vice-President, Finance	N/A	Vice-President, Finance of Bellatrix since April 2013 and prior thereto, Treasurer of Bellatrix. Prior to November 2009, Treasurer of True Energy Inc. (as administrator of True Energy Trust). Manager, Finance of True Energy Inc. June 2005 to June 2006. Prior thereto, held progressively senior finance roles with Ketch Resources Ltd., PrimeWest Energy Trust, TransAlta Corporation and Mobil Oil Canada.
David R. Laing Calgary, Alberta, Canada Age: 58	Vice-President, Production	N/A	Vice-President, Production of Bellatrix since December 2014. Prior thereto, Director, Production Operations and Manager, Production Operations with Bellatrix. Formerly Vice-President, Alberta with Dominion Exploration Canada Ltd., a subsidiary of Dominion Resources Inc. of Richmond, Virginia, USA.
Robert O. Lee, CET Cochrane, Alberta, Canada Age: 55	Vice-President, Marketing	N/A	Vice-President, Marketing since March 15, 2017. Prior thereto, Director, Marketing and Commercial of Bellatrix since December 2008. Prior thereto, Manager, Marketing of Bellatrix and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust) since September 2007.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
Russell G. Oicle P. Geol. Calgary, Alberta, Canada Age: 61	Vice-President, Exploration	N/A	Vice-President, Exploration of Bellatrix and, prior to November 1, 2009, of True Energy Inc. (as administrator of True Energy Trust), since November 24, 2008. Prior thereto, from July 2007 to November 2008, Exploration Supervisor of Penn West Energy Trust. From May 2005 to July 2007, President, RGO Resources, a private geological consulting company. From November 2002 to May 2005, Vice-President, Exploration and Chief Operating Officer of Relentless Energy Corp. Prior thereto, Vice-President of Exploration of Ulster Petroleums Ltd.
Mark L. Stephen, P. Eng. Calgary, Alberta, Canada Age: 56	Vice-President, Operations	N/A	Vice-President, Operations of Bellatrix since September 1, 2014. Prior thereto, Director of Drilling and Completions of Bellatrix from December 2013 to August 2014 and prior thereto, Manager of Drilling and Completions from June 2011 to December 2013. Prior thereto, Vice-President of Operations at Orleans Energy Ltd. from April 2007 to May 2011.
Steve G. Toth, CFA Calgary, Alberta, Canada Age: 39	Vice-President, Investor Relations	N/A	Vice-President, Investor Relations of Bellatrix since October 2014. Prior thereto, Director, Oil & Gas Equity Research Analyst at a leading global wealth management and investment firm.
W.C. (Mickey) Dunn Calgary, Alberta, Canada Age: 63	Chairman[(2)(3)]	August 31, 2000	Chairman of Bellatrix and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust); previously director of Precision Drilling Inc. from 1992 to 2013; previously director of The Cash Store Financial Services Inc. from 2003 to 2014; previously director of Vero Energy Inc. from 2006 to 2010; previously President and Chief Executive Officer of Cardium Service and Supply Ltd. and Cardium Tool Services Inc. from 1981 to 1999, and Colorado Silica Sand Inc. from 1981 to 1996.
Murray L. Cobbe Calgary, Alberta, Canada Age: 67	Director[(2)(5)]	September 22, 2006	Chairman and, prior to August 2009, President and Chief Executive Officer of Trican Well Service Ltd. (a publicly traded well service company). Director of Secure Energy Services Inc. since 2009.
John H. Cuthbertson, Q.C. Calgary, Alberta, Canada Age: 66	Director[(3)]	August 31, 2000	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director(1)	Principal Occupation
Keith E. Macdonald, CPA, CA Calgary, Alberta, Canada Age: 60	Director(2)(4)(5)	April 26, 2007	President of Bamako Investment Management Ltd., a private holding and financial consulting company, since July 1994. Mr. Macdonald was the Chief Executive Officer and a director of EFLO Energy Inc. from March 2011 to January 2015. Mr. Macdonald currently serves as a director of Surge Energy Inc., Madalena Ventures Inc.; previously a director of Mountainview Energy Ltd. from 2010 to 2017.
Thomas E. MacInnis Calgary, Alberta, Canada Age: 45	Director(4)	February 6, 2017	Independent businessman; previously head of Financial Markets for National Bank Financial from 2009 to 2017; prior thereto, a founder and Managing Director of Tristone Capital, an energy focused boutique investment banking practice in Calgary, Alberta, from 2000 to 2009.
Steven J. Pully, Esq., CPA, CFA Dallas, Texas, USA Age: 56	Director(2)(3)	January 1, 2015	Independent businessman and consultant and director of VAALCO Energy, Inc. and Energy XXI Gulf Coast, Inc.; previously General Counsel and a Partner of Carlson Capital, L.P., an alternative asset management firm, from January 2008 to September 2014.
Murray B. Todd, B.Sc. P. Eng. Calgary, Alberta, Canada Age: 81	Director(5)	November 2, 2005	President and CEO of Canada Hibernia Holding Corporation (an oil and gas production company).
Keith Turnbull, B.Sc., CPA, CA Calgary, Alberta, Canada Age: 67	Director(4)	January 1, 2014	Business consultant since January 1, 2010. Prior thereto, Partner at KPMG LLP. President of K.S. Turnbull Professional Corporation and currently a director of Crown Point Energy Inc; previously a director of Renegade Petroleum Ltd. from June 2012 to March 2014, Angle from March 2012 to December 2013, CE Franklin Ltd. from April 2010 to July 2012, and UNX Energy Corp. from May 2010 to April 2011.

Notes:

(1) To the extent the date of election or appointment is prior to November 1, 2009, such date reflects the date of election or appointment as a director of True Energy Inc. (administrator of True Energy Trust). The term of each director is until the next annual meeting of Bellatrix or until their successors are elected, but not later than the date of the next annual meeting of Bellatrix.
(2) Member of Compensation Committee.
(3) Member of Corporate Governance Committee.
(4) Member of Audit Committee.
(5) Member of Reserves, Safety and Environment Committee.

As at February 28, 2017, the directors and officers of Bellatrix, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, 3,096,640 Common Shares, representing approximately 1.26**%** of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of Bellatrix, except as described below, no director or executive officer of Bellatrix (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 Bellatrix), that: (a) 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 (b) 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.

Following the resignation of W.C. (Mickey) Dunn from the board of directors of The Cash Store Financial Services Inc. ("**Cash Store Financial**") on January 2, 2014, the company announced that a Cease Trade Order was issued on May 30, 2014 by the Alberta Securities Commission (and subsequently on June 18, 2014 by the Ontario Securities Commission) due to Cash Store Financial failing to file interim financial statements for the 6-month period ended March 31, 2014.

Keith Macdonald served on the board of directors of Mountainview Energy Ltd. ("**Mountainview**") until March 15, 2017. On May 5, 2016, the Alberta Securities Commission issued a Cease Trade Order against Mountainview for failure to file annual audited financial statements, annual management discussion and analysis and certification of annual filing for the fiscal period ended December 31, 2015 (the "**Order**"). As of the date hereof, the Order remains in effect.

Bankruptcies

To the knowledge of Bellatrix, except as described below, no director or executive officer of Bellatrix (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Bellatrix to affect materially the control of Bellatrix: (a) 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 Bellatrix) 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 (b) 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.

W.C. (Mickey) Dunn, the Chairman of the Board, was a director of Cash Store Financial from May 1, 2003 until his resignation on January 2, 2014. On April 14, 2014, Cash Store Financial, The Cash Store Inc., TCS Cash Store Inc., Instaloans Inc., 7252331 Canada Inc., 5515433 Manitoba Inc., 1693926 Alberta Ltd. doing business as "The Title Store" obtained an Initial Order under the Companies' Creditors Arrangement Act (the "**CCAA**"). The applicants sought and were granted the stay of proceedings and other relief provided under the CCAA. On January 4, 2016, 1511419 Ontario Inc., formally known as Cash Store Financial and applicants announced that it had successfully implemented its Plan of Compromise and Arrangement pursuant to the CCAA with an implementation date of December 31, 2015. On November 16, 2016, 1511419 Ontario Inc. was granted a stay extension until November 18, 2017.

Keith Macdonald, a director of Bellatrix, served on the board of directors of Mountainview until March 15, 2017. On October 14, 2016, a wholly-owned entity of Mountainview, Mountainview Divide LLC which owned key assets in North Dakota, filed a voluntary petition under Chapter 11 of the United States Bankruptcy Code.

Charles R. Kraus, the Executive Vice-President, General Counsel and Corporate Secretary of Bellatrix, was an officer of Lone Pine Resources Inc. ("**Lone Pine**"), an oil and natural gas company, from September 6, 2011 until September 2, 2014. On September 25, 2013, Lone Pine commenced proceedings in the Court of Queen's Bench of Alberta under the CCAA and ancillary proceedings under Chapter 15 of the United States Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware. On January 31, 2014, Lone Pine completed its emergence from creditor protection under the CCAA and Chapter 15 of the United States Bankruptcy Code. Lone Pine, Lone Pine Resources Canada Ltd. and all other subsidiaries of Lone Pine were parties to the CCAA and Chapter 15 proceedings.

Penalties and Sanctions

To the knowledge of Bellatrix, no director or executive officer of Bellatrix (nor any personal holding company of any of such persons) or shareholder holding a sufficient number of securities of Bellatrix to affect materially the control of Bellatrix has been subject to: (i) 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 (ii) 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 of Interest

There are potential conflicts of interest to which the directors and officers of Bellatrix will be subject to in connection with the operations of Bellatrix. In particular, certain of the directors and officers of Bellatrix 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 Bellatrix or with entities which may, from time to time, provide financing to, or make equity investments in, its competitors. In accordance with the ABCA, directors who have a material interest or any person who is a party to a material contract or a proposed material contract with Bellatrix are required, subject to certain exceptions, to disclose that interest and generally abstain from voting on any resolution to approve the contract.

DISCLOSURE PURSUANT TO THE REQUIREMENTS OF THE NEW YORK STOCK EXCHANGE

As a foreign private issuer listed on the NYSE, Bellatrix is not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic Canadian requirements. Bellatrix is, however, required to comply with the following NYSE Rules: (i) Bellatrix must have an audit committee that satisfies the requirements of Rule 10A-3 under the United States Securities Exchange Act of 1934, as amended; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any non-compliance with the applicable NYSE rules; (iii) submit an executed Section 303A annual written affirmation to the NYSE, as well as a Section 303A interim affirmation each time certain changes occurs to the audit committee; and (iv) provide a brief description of any significant differences between its corporate governance practices and those followed by U.S. domestic issuers under NYSE listing standards. Bellatrix has reviewed the NYSE listing standards followed by U.S. domestic issuers listed under the NYSE and confirms that its corporate governance practices do not differ significantly from such standards.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate of the Audit Committee of the Board is attached hereto as Appendix "C".

Composition of the Audit Committee

The following table sets forth the names of each current member of the Audit Committee, whether such member is independent, whether such member is financially literate and the relevant education and experience of each such member:

Name and municipality of residence	Independent	Financially literate	Relevant education and experience
Keith E. Macdonald, CPA, CA	Yes	Yes	Mr. Macdonald is the President of Bamako Investment Management Ltd., a private holding and financial consulting company and has held such position since July 1994. Mr. Macdonald was the Chief Executive Officer and a director of EFLO Energy Inc. from March 2011 to January 2015. He is a also a director of Surge Energy Inc. and Madalena Ventures Inc. Mr. MacDonald is a Chartered Accountant.

Name and municipality of residence	Independent	Financially literate	Relevant education and experience
Keith Turnbull, B.Sc. CPA, CA Calgary, Alberta, Canada	Yes	Yes	Mr. Turnbull is a Chartered Accountant and has been a business consultant since his retirement as a Partner from KPMG LLP on December 31, 2009, after nearly 30 years of service. Mr. Turnbull has extensive experience in all aspects of public company accounting, finance and management matters, including serving as Office Managing Partner at KPMG LLP's Calgary office, where he was responsible for the strategic direction and growth of the Calgary practice, as well its audit, tax and advisory business. Mr. Turnbull is a member of the Alberta and Canadian Institute of Chartered Accountants and the Institute of Corporate Directors. Mr. Turnbull is currently a director and chair of the audit committee of Crown Point Energy Inc.
Thomas E. MacInnis Calgary, Alberta, Canada	Yes	Yes	Mr. MacInnis is an independent businessman and was previously the head of financial markets at National Bank Financial from 2009 to 2017. Mr. MacInnis has a masters of business administration from the Richard Ivey School of Business, a professional engineering diploma from the Southern Alberta Institute of Technology and a bachelor of commerce from Saint Mary`s University. Mr. MacInnis is a member of the Institute of Corporate Directors. Mr. MacInnis is currently a director of Lex Capital Partners Fund, Lex Energy Partners Fund and Lex Energy Partners II Fund and serves on such funds investment committees.

Pre-Approval Policies and Procedures

The Audit Committee has adopted an Auditor Services Pre-Approval Policy (the "**Policy**") with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP, the Corporation's independent auditor. Pursuant to the Policy, the Audit Committee on an annual basis may approve the provision of a specified list of audit and permitted non-audit services that the Audit Committee believes to be typical, re-occurring or otherwise likely to be provided by KPMG LLP during the current fiscal year. The list of services should be sufficiently detailed as to the particular services to be provided to ensure that the Audit Committee knows precisely what services it is being asked to pre-approve and it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

In addition, pursuant to the Policy, the Audit Committee has delegated its pre-approval authority to the Chair of the Audit Committee. The Chair of the Audit Committee is required to report any granted pre-approvals to the Audit Committee at its next scheduled meeting. The Audit Committee shall not delegate to management the Audit Committee's responsibilities for pre-approving audit and non-audit services to be performed by KPMG LLP.

Pursuant to the Policy, there is an exception to the pre-approval requirements for permitted non-audit services, provided all such services were not recognized at the time of the engagement to be non-audit services and, once recognized, are promptly brought to the attention of the Audit Committee and approved prior to the completion of the audit. The aggregate amount of all services approved in this manner may not constitute more than five percent of the total fees paid to KPMG LLP during the fiscal year in which the services are provided.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by Bellatrix's external auditor in each of the last two fiscal years for audit services including the annual audit, reviews of interim consolidated financial statements, internal control compliance, international financial reporting standards, compliance for NYSE listing and due diligence work in respect of financings and a corporate acquisition were $928,590 in 2016 and $1,050,525 in 2015.

Audit – Related Fees

There was no fees in 2016 and $74,460 in 2015 billed for French translation services by the external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under "*Audit Fees*" above.

Tax Fees

There was $13,910 in 2016 and no fees in 2015 billed for professional services rendered by the external auditor for tax compliance, tax advice and tax planning.

All Other Fees

No other professional services fees were billed by the external auditor for other non-audit related fees in 2016 or 2015.

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, including the governments of Canada, Alberta, British Columbia, and Saskatchewan, all of which investors in the oil and gas industry should carefully consider. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments governments may enact in the future. The following comprises some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada that may affect the Corporation.

Pricing and Marketing

Oil

In Canada, producers of oil are entitled to negotiate sales contracts directly with oil purchasers, which results in the market determining 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. Exporters of oil from Canada 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 underwent a consultation process to update the regulations governing the issuance of export licences. The updating process was necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. The *Regulations Amending the National Energy Board Act Part VI (Oil and Gas) Regulations* came into effect on July 31, 2015 and provides the requirements for obtaining long-term licences.

Natural Gas

Canada'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, 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, Intercontinental Exchange or the New York Mercantile Exchange 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 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 40 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. The new administration in the United States has indicated an intention to seek renegotiation of NAFTA, the impact of which on the oil and gas industry is uncertain.

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 crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the working interest owner's interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests, or net carried interests.

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

The Canadian federal government has signaled it will, *inter alia*, phase out subsidies for the oil and gas industry, which include only allowing the use of the Canadian Exploration Expenses tax deduction in cases of successful exploration, implementing stringent reviews for pipelines, and establishing a pan-Canadian framework for combating climate change. These changes could affect earnings of companies operating in the oil and natural gas industry.

Alberta

In Alberta, the Crown owns 81% of the province’s mineral rights. The remaining 19% are owned by the federal government on behalf of First Nations or in National Parks, and by individuals and companies. Provincial government royalty rates apply to Crown-owned mineral rights. On January 29, 2016, the Government of Alberta released and accepted the Royalty Review Advisory Panel's recommendations, which outlined the implementation of a "Modernized Royalty Framework" for Alberta (the "**MRF**"). The MRF formally took effect on January 1, 2017.

Wells drilled prior to January 1, 2017 will continue to be governed by the "New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) (the "Alberta Royalty Framework") for a period of 10 years until January 1, 2027. The MRF is structured in three phases: (i) pre-payout, (ii) mid-life, and (iii) mature. During the pre-payout phase, a fixed 5% royalty will apply until the well reaches payout. Well payout occurs when the cumulative revenue from a well is equal to the drilling and completion cost allowance (determined by a formula that approximates drilling and completion costs for wells based on total depth, length, and proppant placed). The new royalty rate for pre-payout under the MRF will be payable on gross revenue generated from all production streams (oil, gas, and natural gas liquids), eliminating the need to label a well as "oil" or "gas". Post-payout, the mid-life phase will apply a higher royalty rate than the pre-payout phase which, depending on the commodity price of the substance the well is producing, could range from 5% to 40%. The metrics for calculating the mid-life phase royalty are based on commodity prices and is intended, on average, to yield the same internal rate of return as under the Alberta Royalty Framework. In the mature phase of the MRF, once a well reaches the tail end of its cycle and production falls below a maturity threshold, currently the equivalent of 194 m^3 (40 barrels of oil equivalent per day or 345,500 m^3 of gas per month), the royalty rate will move to a sliding scale (based on volume and price) with a minimum royalty rate of 5%. The downward adjustment of the royalty rate in the mature phase is intended to account for the higher per-unit fixed cost involved in operating an older well.

On January 1, 2017, the Enhanced Hydrocarbon Recovery Program and the Emerging Resources Program came into effect. These programs are a part of the MRF and account for the higher costs associated with enhanced recovery methods and with developing emerging resources, respectively, in an effort to make difficult investments economically viable and to increase royalties. Each program contains certain eligibility criteria that must be satisfied in order for a proposed project to fall under the respective program. Enhance recovery scheme applications can be submitted to the AER.

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

Royalties, for wells drilled prior to January 1, 2017, are paid pursuant to the Alberta Royalty Framework, until January 1, 2027. Royalty rates for conventional oil are set by a single sliding scale 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 depends on the price of each of the components of the gas stream, the productivity of the well, its acid gas factor and the depth of the producing zone. These factors are employed on a sliding rate formula to determine the natural gas royalty rate per well with the maximum royalty payable under the royalty regime set at 36% and a minimum royalty rate of 5%.

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 lands where the Crown does not hold the rights to mines and minerals 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 freehold 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**"). These initiatives apply to wells drilled before January 1, 2017, for a 10 year period, until January 1, 2027. Specifically:

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months 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 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.

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 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 applicable freehold production tax is based on the volume of monthly production, and 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 applicable freehold production tax is 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%. Additionally, owners of mineral rights in British Columbia must pay an annual mineral land tax that is equivalent to $4.94 per hectare of producing lands. Non-producing lands are taxed on a sliding scale depending on the total number of hectares owned by the entity.

The Government of 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. Effective April 1, 2014, there are two tiers to the Deep Well Royalty Credit Program, "tier one" and "tier two". Tier one of the Deep Well Royalty Credit Program applies to shallower horizontal wells with a true vertical depth less than or equal to 1,900 metres if spud after March 31, 2014. Tier two applies to vertical wells spud on or after January 1, 2009 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, is intended to reflect the higher drilling and completion costs. Currently, all wells that qualify for the tier one royalty credits are subject to a minimum royalty of 6% while wells that qualify for the tier two royalty credits are subject to a minimum royalty of 3%. These minimum royalty amounts apply when the net royalty payable would otherwise be zero for a production month;

- *Deep Well Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay if the re-entry well event 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 m3 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 m3 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 Well Royalty Reduction Program* providing a monthly royalty reduction for low productivity natural gas wells with an average daily rate of production less than 23 m3 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 25,000m3;

- *Ultra-Marginal Well 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 17m3 per metre of depth for exploratory wildcat wells and less than 11m3 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 60,000m3. Horizontal wells spud on or after April 1, 2014 are not eligible for the Ultra-Marginal Royalty Reduction Program 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 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.

Saskatchewan

In Saskatchewan, the Crown owns approximately 70% of the oil and gas rights. For the Crown lands, taxes (the "**Resource Surcharge**") and royalties are applicable to revenue generated by corporations focused on oil and gas operations.

A Resource Surcharge on the value of sales of oil, natural gas, potash, uranium and coal in Saskatchewan is levied under authority of *The Corporation Capital Tax Act*. For resource corporations, the Resource Surcharge rate is 3% of the value of sales of all potash, uranium and coal produced in Saskatchewan, and oil and natural gas produced from wells drilled in Saskatchewan prior to October 1, 2002. For oil and natural gas produced from wells drilled in Saskatchewan after September 30, 2002, the Resource Surcharge rate is 1.7% of the value of sales. The Resource Surcharge applies to resource trusts in addition to resource corporations. In addition, a mineral rights tax is charged to owners of mineral rights paid on an annual basis at the rate of $1.50 per acre owned.

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 Government of Saskatchewan, 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 250,000 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 GJ for third and fourth tier gas and $0.95 per GJ 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 wellhead 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 m3 for deep development vertical oil wells, 4,000 m3 for non-deep exploratory vertical oil wells and 16,000 m3 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 m3 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 m3 for non-deep horizontal oil wells and 16,000 m3 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 m3 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.

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licences and applications in the oil and gas sector by eliminating 11 different licensing fees, which resulted in an aggregate of 20,000 fee transactions per year, and replacing them with a single annual levy based on a company's production and number of wells. Effective October 27, 2016, the Saskatchewan Ministry of the Economy streamlined a further 20 different service fees, and implemented a Crown Minerals Electronic Registry for oil and gas tenure in Saskatchewan that will provide for certainty of tenure comparable to Alberta and reduce the administrative burden.

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 have 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, the Government of 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 issued on or after January 1, 2009, at the conclusion of the primary term of the lease or license.

Production and Operation Regulations

The oil and natural gas industry in Canada is highly regulated and subject to significant control by provincial regulators. Regulatory approval is required for, among other things, the drilling of oil and natural gas wells, construction and operation of facilities, the storage, injection and disposal of substances and the abandonment and reclamation of well-sites. In order to conduct oil and gas operations and remain in good standing with the applicable provincial regulator, we must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance with such legislation, regulations, orders, directives or other directions can be costly and a breach of the same may result in fines or other sanctions.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulation under a variety of provincial, federal and municipal laws and regulations, 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. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such 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. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, may impose further requirements on operators and other companies in the oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of the federal government and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail, however, such conflicts are uncommon. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport. The *Canadian Environmental Protection Act, 1999* and the *Canadian Environmental Assessment Act, 2012* provide the foundation for the federal government to protect the environment and cooperate with provinces to do the same.

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 environmental 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.

On June 20, 2016, the Federal Government launched a review of current environmental and regulatory processes with a focus on rebuilding trust in the environmental assessment processes, modernizing the NEB, and introducing modernized safeguards to both the *Fisheries Act* and the *Navigation Protection Act*. A panel has been formed and public consultations are ongoing. It is expected that the panel will provide the Minister of Environment and Climate Change with a report and recommendations, expected by March 31, 2017. At such time, the Minister of Environment and Climate Change will consider the recommendations in the Panel’s report and identify next steps to improve federal environmental processes, which is expected to take place during the summer/fall of 2017. Until this process is complete, the Federal Government's interim principles released January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The Federal Government has not provided any indication on what changes, if any, will be implemented or when, but increased delays and uncertainty surrounding the environmental assessment process should be expected for large projects.

On November 29, 2016, the Government of Canada announced that it would introduce legislation by spring 2017 to formalize a moratorium for crude oil tankers on British Columbia's north coast. It is unclear how the proposed moratorium may affect ongoing liquefied natural gas export projects currently under consideration and development. On the same day, the Government of Canada also approved, subject to a number of conditions, the Trans Mountain Pipeline system expansion backed by Kinder Morgan Canada as well as the replacement of Enbridge Inc.'s plan to replace its Line 3 pipeline system, while also rejecting Enbridge Inc.'s proposed Northern Gateway project. On January 11, 2017, the Government of British Columbia confirmed that the conditions to the approval of the Trans Mountain Pipeline have been satisfied. Additionally, the new administration in the United States has indicated a willingness to revisit other pipeline projects that had been previously rejected.

Alberta

The AER is the single regulator responsible for all energy development in Alberta. The AER ensures the safe, efficient, orderly, and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. 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 a single regulator is 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.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. The following frameworks, plans and policies form the basis of Alberta's Integrated Resource Management System ("**IRMS**"). The IRMS method to natural resource management sets out to engage and consult with stakeholders and the public and examines the cumulative impacts of development on the environment and communities, by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including Alberta Environment and Parks, Alberta Energy, the Policy Management Office, the Aboriginal Consultation Office, and the Land Use Secretariat.

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.

In July 2014, the Government of Alberta approved the South Saskatchewan Regional Plan ("**SSRP**") which came into force on September 1, 2014. The SSRP is the second regional plan developed under the ALUF. The SSRP covers approximately 83,764 square kilometres and includes 44% of the provincial population.

The SSRP creates four new and four expanded conservation areas, and two new and six expanded provincial parks and recreational areas. The SSRP will honour existing petroleum and natural gas tenure in conservation and provincial recreational areas. However, any new petroleum and natural gas tenures sold in conservation areas, provincial parks, and recreational areas will prohibit surface access. However, oil and gas companies must minimize impacts of activities on the natural landscape, historic resources, wildlife, fish and vegetation when exploring, developing and extracting the resources. Freehold mineral rights will not be subject to this restriction.

Phase 1 Consultation of the North Saskatchewan Region Plan ("**NSRP**") has been completed and the Regional Advisory Council is currently preparing its Recommendation to Government report. The NSRP is located in central Alberta and is approximately 85,780 square kilometres in size and affects activities in central Alberta, and encompasses an area between the province's borders with British Columbia and Saskatchewan. The Upper Peace Region Plan, Lower Peace Region Plan, Red Dear Region Plan and Upper Athabasca Region Plan have not been started.

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*, in conjunction with the OGAA, 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, the Government of 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, the Government of Saskatchewan has implemented a number of operational requirements, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural requirements including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

In Alberta, the AER administers 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. Alberta's *Oil and Gas Conservation Act* ("**OGCA**") 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 or is unable to meet its obligations. 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 licensees and to 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. The AER publishes the liability management rating for each licensee on a monthly basis.

Made effective in three phases, from May 1, 2013 to August 1, 2015, the AER implemented important changes to the AB LLR Program (the "**Changes**") that resulted in a significant increase in the number of oil and gas companies in Alberta that are required to post security. The Changes affect the deemed parameters and costs used in the formula that calculates the ratio of deemed liabilities to deemed assets under the AB LLR Program, increasing a licensee's deemed liabilities and rendering the industry average netback factor more sensitive to asset value fluctuations. The Changes stem from concern that the previous regime significantly underestimated the environmental liabilities of licensees.

On June 20, 2016, the AER issued Bulletin 2016-16, *Licensee Eligibility—Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision* ("**Bulletin 16**") in an urgent response to a decision from the Alberta Court of Queen's Bench, which is currently under appeal with the Court of Appeal of Alberta. In *Redwater Energy Corporation (Re)*, 2016 ABQB 278 ("**Redwater**"), Chief Justice Wittman found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA and the *Bankruptcy and Insolvency Act* ("**BIA**"), and that receivers and trustees have the right to renounce assets within insolvency proceedings. Such a conflict renders the AER's legislated authority unenforceable to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any resources of the insolvent licensee will first be used to satisfy secured creditors under the *BIA*. Bulletin 16 provides interim rules to govern while the case is appealed and while the Government of Alberta can develop appropriate regulatory measures to adequately address environmental liabilities. Three changes were implemented to minimize the risk to Albertans:

1. The AER will consider and process all applications for licence eligibility under *Directive 067: Applying for Approval to Hold EUB Licenses* as non-routine and may exercise its discretion to refuse an application or impose terms and conditions on a licence eligibility approval if appropriate in the circumstances.
2. For holders of existing but previously unused licence eligibility approvals, prior to approval of any application (including licence transfer applications), the AER may require evidence that there have been no material changes since approving the licence eligibility. This may include evidence that the holder continues to maintain adequate insurance and that the directors, officers, and/or shareholders are substantially the same as when licence eligibility was originally granted.
3. As a condition of transferring existing AER licences, approvals, and permits, the AER will require all transferees to demonstrate that they have a liability management ratio ("**LMR**") of 2.0 or higher immediately following the transfer.

In order to clarify and revise the interim rules in Bulletin 16, the AER issued Bulletin 2016-21 ("**Bulletin 21**") on July 8, 2016 and reaffirmed its position that an LMR of 1.0 is not sufficient to ensure that licensees will be able to address their obligations throughout the life cycle of energy development, and an LMR of 2.0 remains the requirement for transferees. However, Bulletin 21 did provide the AER with additional flexibility to permit licensees to acquire additional AER-licensed assets if:

- the licensee already has an LMR of 2.0 or higher;
- the acquisition will improve the licensee's LMR to 2.0 or higher; or
- the licensee is able to satisfy its obligations, notwithstanding an LMR below 2.0, by other means.

The AER provided no indication of what other means would be considered, and it is likely the interim measures will cause delays in completing transactions and may also reduce the pool of possible purchasers. However, transactions have been approved following a more rigorous review by the AER, despite a transferee's LMR not meeting the interim requirement. The Alberta Court of Appeal heard the appeal of the *Redwater* decision on October 11, 2016, with the Court reserving its decision.

The AER implemented the inactive well compliance program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within 5 years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission system. The AER announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota.

British Columbia

In British Columbia, the Commission oversees the Liability Management Rating Program ("**BC 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 BC 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 the Economy administers 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. Following the Redwater decision in Alberta, on August 19, 2016, the Ministry of Economy announced that all license transfer applications in Saskatchewan will be considered non-routine until further notice and the minister will not be strictly relying on the standard licensee liability ratio in evaluating deposit requirements. The minister will consider a number of factors in calculating deposit requirements. It is likely that these changes will cause delays in completing transactions and may also reduce the pool of possible purchasers.

Climate Change Regulation

Federal

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the oil and natural gas industry in Canada. Such regulations, surveyed below, impose certain costs and risks on the industry.

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 basis, 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.

As a signatory to the *United Nations Framework Convention on Climate Change* ("**UNFCCC**") and a participant to the Copenhagen Accord (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 GHG emissions from 2005 levels by 2020; however, the GHG emission reduction targets are not binding. In May 2015, Canada submitted its Intended Nationally Determined Contribution ("**INDC**") to the UNFCCC. INDCs were communicated prior to the 2015 United Nations Climate Change Conference, held in Paris, France, which led to the Paris Agreement that came into force November 4, 2016 (the "**Paris Agreement**"). Among other items, the Paris Agreement constitutes the actions and targets that individual countries will undertake to help keep global temperatures from rising more than 2° Celsius and to pursue efforts to limit below 1.5° Celsius. The Government of Canada ratified the Paris Agreement on December 12, 2016, and pursuant to the agreement, Canada's INDC became its Nationally Determined Contributions ("**NDC**"). As a result, the Government of Canada replaced its INDC of a 17% reduction target established in the Copenhagen Accord with an NDC of 30% reduction below 2005 levels by 2030

On June 29, 2016, the North American Climate, Clean Energy and Environment Partnership was announced among Canada, Mexico and the United States, which announcement included an action plan for achieving a competitive, low-carbon and sustainable North American economy. The plan includes setting targets for clean power generation, committing to implement the Paris Agreement, setting out specific commitments to address certain short-lived climate pollutants, and the promotion of clean and efficient transportation.

Additionally, on December 9, 2016, the Government of Canada formally announced the Pan-Canadian Framework on Clean Growth and Climate Change. As a result, the federal government will implement a Canada-wide carbon pricing scheme beginning in 2018. This may be implemented through either a cap and trade system or a carbon tax regime at the option of each province or territory. The federal government will impose a price on carbon of $10 per tonne on any province or territory which fails to implement its own system by 2018. This amount will increase by $10 annually until it reaches $50 per tonne in 2022 at which time the program will be reviewed.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as it is currently not possible to predict the extent of future requirements. Any new laws and regulations, or additional requirements to existing laws and regulations, could have a material impact on the Corporation's operations and cash flow.

Alberta

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 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 is the first jurisdiction in North America to impose regulations requiring large facilities in various sectors to reduce their GHG emissions. The SGER applies to Alberta facilities emitting more than 100,000 tonnes of GHG emissions a year ("**Regulated Emitters**"), 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.

On June 25, 2015, the Government of Alberta renewed the SGER for a period of two years with significant amendments while Alberta's newly formed Climate Advisory Panel conducted a comprehensive review of the province's climate change policy. As of 2015, Regulated Emitters are required to reduce their emissions intensity by 2% from their 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, 10% of their baseline in the eighth year, and 12% of their baseline in the ninth or subsequent years. These reduction targets will increase, meaning that Regulated Emitters in their ninth or subsequent years of commercial operation must reduce their emissions intensity from their baseline by 15% in 2016 and 20% in 2017.

A Regulated Emitter can meet its emissions intensity targets through a combination of the following: (1) producing its products with lower carbon inputs, (2) purchasing emissions offset credits from non-regulated emitters (generated through activities that result in emissions reductions in accordance with established protocols), (3) purchasing emissions performance credits from other Regulated Emitters that earned credits through the reduction of their emissions below the 100,000 tonne threshold, (4) cogeneration compliance adjustments, and (5) by contributing to the Climate Change and Emissions Management Fund (the "**Fund**"). Contributions to the Fund were initially made at a rate of $15 per tonne of GHG emissions, increasing to a rate of $20 per tonne of GHG emissions in 2016 and $30 per tonne of GHG emissions in 2017. Proceeds from the Fund are directed at testing and implementing new technologies for greening energy production.

On November 22, 2015, as a result of the Climate Advisory Panel's Climate Leadership report, the Government of Alberta announced its Climate Leadership Plan. On January 1, 2017, the *Climate Leadership Act* ("**CLA**") came into force and introduced a carbon tax on consumers of all carbon-emitting fuels. An initial economy-wide levy of $20 per tonne was implemented and such levy will increase to $30 per tonne in January of 2018. All fuel consumption— including gasoline and natural gas— is subject to the levy, with certain exemptions, and directors of a corporation may be held jointly and severally liable with a corporation when the corporation fails to remit an owed carbon levy. Regulated Emitters will remain subject to the SGER framework until the end of 2017. Upon the expiry of the SGER, the Government of Alberta intends to transition to a proposed Carbon Competitiveness Regulation ("**CCR**"), in which sector specific output- based carbon allocations will be used to ensure competitiveness. A 100 megatonne per year limit for GHG emissions was implemented for oil sands operations, which currently emit roughly 70 megatonnes per year. This cap exempts new upgrading and cogeneration facilities, which are allocated a separate 10 megatonne limit. Regulations accompanying the CLIA have not yet been released.

In addition to enacting the *CLA*, the *Climate Leadership Implementation Act* also enacted the *Energy Efficiency Alberta Act,* which enables the creation of Energy Efficiency Alberta, a new Crown corporation to support and promote energy efficiency programs and services for homes and businesses.

Alberta is also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion over 15 years to fund two large-scale carbon capture and storage 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.

British Columbia

British Columbia launched its Climate Action Plan in 2008 and met its first interim emission reduction targets in 2012. In February 2008, the Government of 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 GHG emissions. The final scheduled increase took effect on July 1, 2012, wherein the Government of British Columbia froze the tax level to allow other jurisdictions time to adopt comparable carbon pricing mechanisms. In order to make the tax revenue-neutral, the Government of 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.

Further, on April 3, 2008, the Government of 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 *Greenhouse Gas Emission Reporting Regulation*, implemented under the authority of the *Cap and Trade Act*, sets out the requirements for the reporting of 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. The reporting system for large emitters of GHGs has since been streamlined by the *Greenhouse Gas Industrial Reporting and Control Act* (the "***GGIRCA***") and its associated regulations that came into force on January 1, 2016. The *GGIRCA* sets out benchmarked performance standards for different industrial facilities and sectors, provides for emissions offsets through the purchase of emission credits or emission offsetting projects, among other measures, and replaces the *Cap and Trade Act*.

Following the 2012 Budget, the Government of British Columbia undertook 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, the Government of British Columbia confirmed that it will keep its revenue-neutral carbon tax–the current carbon tax rates, tax base will be maintained, and revenues will continue to be returned through tax reductions.

On August 19, 2016, the Government of British Columbia unveiled its Climate Leadership Plan with a goal to reduce net annual GHG emissions by up to 25 million tonnes below current forecasts by 2050, and reaffirmed that it will achieve its 2050 target of an 80% reduction in emissions from 2007 levels. In addition to various measures across the economy that are designed to incentivize the growth of the renewable energy sector, the use of low GHG emitting technologies, and the improvement of energy efficiency, among other goals, the Government of British Columbia will soon implement a formal policy to regulate carbon capture and storage projects. Further, the Climate Leadership Plan sets out a strategy to reduce methane emissions in the upstream natural gas sector, beginning with a Legacy phase that targets a 45% reduction in fugitive and vented emissions by 2025 for facilities built before January 1, 2015, followed by a Transition phase for facilities built between 2015 and 2018 that involves a new offset protocol and a Clean Infrastructure Royalty Credit Program along with other incentives, and finally a Future phase that will implement standards going forward.

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. Although the MRGGA and related regulations have yet to be proclaimed in force, draft versions indicate that the Government of Saskatchewan will permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to the federal climate change initiatives. It remains unclear whether the scheme implemented by the MRGGA will be based on emissions intensity or an absolute cap on emissions.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Corporation's other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with the Corporation's business and the oil and natural gas business generally.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, the Corporation's existing reserves, and the production from them, will decline over time as the Corporation produces from such reserves. A future increase in the Corporation's reserves will depend on both the ability of the Corporation to explore and develop its existing properties and its ability to select and acquire suitable producing properties or prospects. There is no assurance that the Corporation will be able to continue to find satisfactory properties to acquire or participate in. Moreover, management of the Corporation may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participations uneconomic. There is also no assurance that the Corporation will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells as well as from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs.

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, and 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, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property, the environment and personal injury. Particularly, the Corporation may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Corporation.

Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in China and other emerging economies, market volatility and disruptions in Asia, and sovereign debt levels and political upheavals in various countries, have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by the recent changes in government at a federal level and, in the case of Alberta, the provincial level and the resultant uncertainty surrounding regulatory, tax, royalty changes and environmental regulation that may be implemented by the new governments. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in western Canada. Lower commodity prices may also affect the volume and value of the Corporation's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have reduced, and are anticipated to continue to reduce, the Corporation's cash flow which could result in a reduced capital expenditure budget. As a result, the Corporation may not be able to replace its production with additional reserves and both the Corporation's production and reserves could be reduced on a year over year basis. Any decrease in value of the Corporation's reserves may reduce the borrowing base under the Credit Facilities, which, depending on the level of the Corporation's indebtedness, could result in the Corporation having to repay a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, the Corporation may have difficulty raising additional funds in the future or if it is able to do so, it may be on unfavourable and highly dilutive terms.

Prices, Markets and Marketing

Numerous factors beyond the Corporation's control do, and will continue to affect the marketability and price of oil and natural gas acquired, produced or discovered by the Corporation. The Corporation's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance the Corporation's reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect the Corporation.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic and political conditions, in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and the Corporation's ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, and OPEC's recent decisions pertaining to the oil production of OPEC member countries, and non-OPEC member countries' decisions on production levels, among other factors. A material decline in prices could result in a reduction of the Corporation's net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of the Corporation's reserves. The Corporation might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in the Corporation's expected net production revenue and a reduction in its oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the Corporation's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

See "*Weakness in the Oil and Gas Industry*".

Volatility of Market Price of Common Shares

The market price of the Common Shares may be volatile. The volatility may affect the ability of holders to sell the Common Shares at an advantageous price. Market price fluctuations in the Common Shares may be due to the

Corporation's operating results failing to meet the expectations of securities analysts or investors in any quarter, downward revision in securities analysts' estimates, governmental regulatory action, adverse change in general market conditions or economic trends, acquisitions, dispositions or other material public announcements by the Corporation or its competitors, along with a variety of additional factors, including, without limitation, those set forth under the heading "*Forward Looking Statements*". In addition, the market price for securities in the stock markets, including the TSX and the NYSE, has recently experienced significant price and trading fluctuations. These fluctuations have resulted in volatility in the market prices of securities that are often unrelated or disproportionate to changes in operating performance. These broad market fluctuations may adversely affect the market price of the Common Shares.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Corporation considers acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Corporation's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Corporation. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets may be periodically disposed of so the Corporation can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Corporation, if disposed of, may realize less than their carrying value on the financial statements of the Corporation.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. During the recent presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of NAFTA, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and gas companies, including the Corporation.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement it could have an adverse effect on the Corporation's ability to market its products internationally, increase costs for goods and services required for the Corporation's operations, reduce access to skilled labour and negatively impact the Corporation's business, operations, financial conditions and the market value of the Common Shares.

Reliance on Joint Venture Partners

The Corporation relies on joint venture partners with respect to the evaluation, acquisition and development of, and future production from, certain of its properties and a failure or inability to perform or a differing development objective by such partners, including, without limitation, O'Chiese Energy Limited Partnership, could materially affect the development of such properties.

Operational Dependence

Other companies operate some of the assets in which the Corporation has an interest. The Corporation has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the

Corporation's financial performance. The Corporation's return on assets operated by others depends upon a number of factors that may be outside of the Corporation's control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which the Corporation has an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which the Corporation has an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations the Corporation may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, the Corporation potentially becoming subject to additional liabilities relating to such assets and the Corporation having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Project Risks

The Corporation manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Corporation's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Corporation's control, including:

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

Because of these factors, the Corporation could be unable to execute projects on time, on budget, or at all, and may be unable to market the oil and natural gas that it produces effectively.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering and processing facilities and pipeline systems, some of which it does not own. The amount of oil and natural gas that the Corporation can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines, and in particular the processing facilities, could result in the Corporation's inability to realize the full economic potential of its production or in a reduction of the price offered for the Corporation's production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect the Corporation's production, operations and financial results. Furthermore, producers are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. 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 the Corporation's business and, in turn, the Corporation's financial condition, results of operations and cash flows. The federal government has signaled that it plans to review the National Energy Board approval process for large projects. This may cause the timeframe for project approvals to increase for current and future applications.

A portion of the Corporation's production may, from time to time, be processed through facilities owned by third parties and over which the Corporation does not have control. 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 discontinuation or decrease of operations could have a materially adverse effect on the Corporation's ability to process its production and deliver the same for sale.

Competition

The petroleum industry is competitive in all of its phases. The Corporation competes with numerous other entities in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Corporation's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Corporation. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than the Corporation. The Corporation's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, methods, and reliability of delivery and storage.

Cost of New Technologies

The oil industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Corporation. There can be no assurance that the Corporation will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. There can also be no assurance that the Corporation will be able to successfully implement such technologies. One or more of the technologies currently utilized by the Corporation or implemented in the future may become obsolete. In such case, the Corporation's business, financial condition and results of operations could be affected adversely and materially. If the Corporation is unable to utilize the most advanced commercially available technology, or is unsuccessful in implementing certain technologies, its business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. The Corporation cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Corporation's business, financial condition, results of operations and cash flows.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Amendments to these controls and regulations may occur from time to time in response to economic or political conditions. See: "*Industry Conditions*". The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase the Corporation's costs, either of which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In order to conduct oil and natural gas operations, the Corporation will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the provincial and federal level. There can be no assurance that the Corporation will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that it may wish to undertake. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, the Corporation's 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).

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of the Corporation's projects. An increase in royalties would reduce the Corporation's earnings and could make future capital investments, or the Corporation's operations, less economic. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. See "*Industry Conditions – Royalties and Incentives*".

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Corporation's 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 the Corporation is ultimately able to produce from its reserves.

Due to seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay Zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to operations, the implementation of a response plan to address potential events, and the suspension of operations if a seismic event above a particular threshold occurs. The AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. See: "*Industry Conditions – Environmental Regulation*". Environmental 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. 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 environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Corporation to incur costs to remedy such discharge. Although the Corporation believes that it will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Liability Management

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 is unable to satisfy its obligations. 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 to the required ratio of the Corporation's deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to the Corporation's compliance requirements. In addition, the liability management system may prevent or interfere with the Corporation's ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. See "*Industry Conditions – Liability Management Rating Program*".

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases which may require the Corporation to comply with GHG emissions legislation at the provincial or federal level. The Corporation works within an environment characterized by concerns over climate change, with environmental limits seen as a legitimate constraint on economic growth and increased activism and public opposition to fossil fuels. In addition, the social value proposition of resource deployment is being challenged. Political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place.

Future laws and regulations may impose significant liabilities on a failure to comply with their requirements. Concerns over climate change and fossil fuel extraction could lead governments to enact additional or more stringent laws and regulations applicable to the Corporation and other companies in the energy industry. Changes in environmental regulation could impact the demand, formulation or quality of our products, or require increased capital expenditures or distribution costs, which may or may not be recoverable in the marketplace. The complexity and breadth of changes in environmental regulation make it extremely difficult to predict the potential impact to the Corporation. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG emissions and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial conditions. See: "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar may negatively affect the Corporation's production revenues. Accordingly, Canadian/United States exchange rates could affect the future value of the Corporation's reserves as determined by independent evaluators. Although a low Canadian dollar relative to the United States dollar may positively affect the price the Corporation receives for its oil and natural gas production, it could also result in an increase in the price for certain goods used for the Corporation's operations, which may have a negative impact on the Corporation's financial results.

To the extent that the Corporation engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Corporation may contract.

An increase in interest rates could result in a significant increase in the amount the Corporation pays to service debt, resulting in a reduced amount available to fund its exploration and development activities and could negatively impact the market price of the Common Shares.

Substantial Capital Requirements

The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- the Corporation's credit rating (if applicable);
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and the Corporation's securities in particular.

Further, if the Corporation's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future drilling programs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Corporation. The Corporation may be required to seek additional equity financing on terms that are highly dilutive to existing shareholders. The inability of the Corporation to access sufficient capital for its operations could have a material adverse effect on the Corporation's business financial condition, results of operations and prospects.

Additional Funding Requirements

The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times and from time to time, the Corporation may require additional financing in order to carry out its oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. Due to the conditions in the oil and gas industry and/or global economic volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. The current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

As a result of global economic and political volatility, the Corporation may from time to time have restricted access to capital and increased borrowing costs. Failure to obtain such financing on a timely basis could cause the Corporation to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Corporation's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Corporation's ability to expend the necessary capital to replace its reserves or to maintain its production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, the Corporation's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of the Corporation's petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be dilutive to existing shareholders. Failure to obtain any financing necessary for the Corporation's capital expenditure plans may result in a delay in development or production on the Corporation's properties.

Credit Facility Arrangements

The Corporation currently has Credit Facilities and the amount authorized thereunder is dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under its Credit Facilities, which includes a single financial ratio covenant, which from time to time either affect the availability, or price, of additional funding. In the event that the Corporation is not able to comply with the covenants, including the financial covenant, the banking syndicate may not be willing to agree to a further amendment to the financial covenant and as a result the Corporation's access to capital could be restricted or repayment could be required.

Even if the Corporation is able to obtain new financing, it may not be on commercially reasonable terms or terms that are acceptable to the Corporation. If the Corporation is unable to repay amounts owing under the Credit Facilities, the lenders under the Credit Facilities could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness. The acceleration of the Corporation's indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, the Corporation's Credit Facilities may impose operating and financial restrictions on the Corporation that could include restrictions on, the payment of dividends, repurchase or making of other distributions with respect to the Corporation's securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

The Corporation's lenders use the Corporation's reserves, commodity prices, applicable discount rate and other factors, to periodically determine the Corporation's borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014. While there has been a moderate improvement in commodity prices recently, there remains a substantial amount of uncertainty as to when and if commodity prices will materially recover. Depressed commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the Credit Facilities. This could result in the requirement to repay a portion, or all, of the Corporation's indebtedness.

Issuance of Debt

From time to time, the Corporation may enter into transactions to acquire assets or shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Corporation's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Corporation may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Corporation's articles nor its by-laws limit the amount of indebtedness that the Corporation may incur. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, the Corporation may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Corporation engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Corporation's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which:

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time the Corporation may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, the Corporation will not benefit from the fluctuating exchange rate.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. The actual interest of the Corporation in properties may accordingly vary from the Corporation's records. If a title defect does exist, it is possible that the Corporation may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect the Corporation's title to the oil and natural gas properties the Corporation controls that could impair the Corporation's activities on them and result in a reduction of the revenue received by the Corporation.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net cash flows from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates and such variations could be material.

The estimation of proved 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 actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves. Such variations could be material.

In accordance with applicable securities laws, the Corporation's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Corporation's oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Corporation intends to undertake in future years. The reserves and estimated cash flows to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in the Corporation's reserves since that date.

Insurance

The Corporation's involvement in the exploration for and development of oil and natural gas properties may result in the Corporation becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Corporation maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, the Corporation may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Corporation. The occurrence of a significant event that the Corporation is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Geopolitical Risks

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by the Corporation. Conflicts, or conversely peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of the Corporation's net production revenue.

In addition, the Corporation's oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of the Corporation's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have insurance to protect against the risk from terrorism.

Dilution

The Corporation may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Corporation which may be dilutive.

Management of Growth

The Corporation may be subject to growth related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Corporation to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Corporation to deal with this growth may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Corporation's properties are held in the form of licences and leases and working interests in licences and leases. If the Corporation or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Corporation's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects.

Canadian and United States Reserves and Production Reporting Practices

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

The primary differences between the Canadian and United States reporting requirements include the following: (i) the Canadian standards require disclosure of proved and probable reserves, while the U.S. standards require disclosure of only proved reserves; (ii) the Canadian standards permit the disclosure of oil and gas resources, while the U.S. standards prohibit such disclosure; (iii) the Canadian standards require the use of forecast prices in the estimation of reserves, while the U.S. standards require the use of 12-month average prices which are held constant; (iv) the Canadian standards require disclosure of reserves on a gross (before royalties) and net (after royalties) basis, while the U.S standards require disclosure on a net (after royalties) basis; (v) the Canadian standards require disclosure of production on a gross (before royalties) basis, while the U.S. standards require disclosure on a net (after royalties) basis; and (vi) the Canadian standards require that reserves and other data be reported on a more granular product type basis than required by the U.S. standards.

This Annual Information Form includes 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. See "*Oil and Gas Information Advisories*".

Dividends

The Corporation has not paid any dividends on its outstanding shares. Payment of dividends in the future will be dependent on, among other things, the cash flow, results of operations and financial condition of the Corporation, the need for funds to finance ongoing operations and other considerations, as the Board considers relevant.

Litigation

In the normal course of the Corporation's operations, it may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Corporation and as a result, could have a material adverse effect on the Corporation's assets, liabilities, business, financial condition and results of operations. Even if the Corporation prevails in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on the Corporation's financial condition.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights in portions of western Canada. The Corporation is not aware that any claims have been made in respect of its properties and assets. However, if a claim arose and was successful such claim may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays which could have a material adverse effect on the Corporation's business and financial results.

Breach of Confidentiality

While discussing potential business relationships or other transactions with third parties, the Corporation may disclose confidential information relating to the business, operations or affairs of the Corporation. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Corporation at competitive risk and may cause significant damage to its business. The harm to the Corporation's business from a breach of confidentiality cannot presently be quantified, but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, the Corporation will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Income Taxes

The Corporation files all required income tax returns and believes that it is in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of the Corporation, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable. In addition, increases in income taxes could have a material adverse effect on the Corporation's financial condition.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects the Corporation. Furthermore, tax authorities having jurisdiction over the Corporation may disagree with how the Corporation calculates its income for tax purposes or could change administrative practices to the Corporation's detriment.

Seasonality

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. In addition, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict the Corporation's ability to access its properties and cause operational difficulties. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding decreases in the demand for the goods and services of the Corporation.

Third Party Credit Risk

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, the Corporation may be exposed to third party credit risk from operators of properties in which the Corporation has a working or royalty interest. In the event such entities fail to meet their contractual obligations to the Corporation, such failures may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may affect a joint venture partner's willingness to participate in the Corporation's ongoing capital program, potentially delaying the program and the results of such program until the Corporation finds a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in the Corporation being unable to collect all or a portion of any money owing from such parties. Any of these factors could materially adversely affect the Corporation's financial and operational results.

Conflicts of Interest

Certain directors or officers of the Corporation may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the ABCA which require a director of officer of a corporation who is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or proposed material contract with the Corporation to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA. See "*Directors and Officers – Conflicts of Interest*".

Reliance on Key Personnel

The Corporation's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The Corporation does not have any key person insurance in effect for the Corporation. The contributions of the existing management team to the immediate and near term operations of the Corporation are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Corporation will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Corporation.

Expansion into New Activities

The operations and expertise of the Corporation's management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future the Corporation may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase the Corporation's exposure to one or more existing risk factors, which may in turn result in the Corporation's future operational and financial conditions being adversely affected.

Security Threats and Other Disruptions

As an oil and gas producer, the Corporation faces various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the security of the Corporation’s facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. The potential for such security threats has subjected the Corporation’s operations to increased risks that could have a material adverse effect on the Corporation’s business. In particular, the implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to the Corporation’s operations and could have a material adverse effect on the Corporation’s reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage the Corporation’s reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Forward-Looking Information May Prove Inaccurate

Shareholders and prospective investors are cautioned not to place undue reliance on the Corporation's forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward-Looking Statements*" of this Annual Information Form.

HUMAN RESOURCES

As at December 31, 2016 Bellatrix employed 158 full-time employees (98 are located in the head office and 60 are field employees) and 73 full-time consultants (16 are located in the head office and 57 are in the field). As at December 31, 2016, Bellatrix employed 1 part-time employee and employed 17 part-time consultants.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as described below, there were no material interests, direct or indirect, of directors or executive officers of Bellatrix, any holder of Common Shares who beneficially owns or controls or directs, directly or indirectly, more than 10% of the outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year which has materially affected or would materially affect Bellatrix.

Orange Capital acquired, through a fund managed or advised by it, approximately US$15 million of the Senior Notes pursuant to the offering of Senior Notes that closed on May 21, 2015 as described under "*General Development of our Business – 2015 Note Offering*". At the time of the Senior Note offering Orange Capital had control or direction over approximately 31,031,114 Common Shares representing approximately 16.17% of the Common Shares issued and outstanding as at such date. Daniel Lewis, who at the time of the Senior Note offering was a director of the Corporation and the Managing Member of Orange Capital, abstained from voting on approving the terms of the Senior Notes. To the knowledge of the Corporation, Orange Capital no longer holds any Common Shares and Daniel Lewis is no longer a director of the Corporation.

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 statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Corporation during, or related to, the Corporation's most recently completed financial year other than InSite, the Corporation's independent reserves evaluators, Sproule, the Corporation's former independent qualified reserves evaluators and KPMG LLP, the Corporation's auditors. InSite and Sproule or their respective "designated professionals" (as defined in Item 16.2(1.1) of Form 51-102F2 of National Instrument 51-102 of the Canadian Securities Administrators) of InSite have not or are not to receive any registered or beneficial interest, direct or indirect, in any of Bellatrix's securities or other property of Bellatrix or of Bellatrix's associates or affiliates, either at the time either InSite or Sproule, as applicable prepared the report, valuation, statement or opinion or any time thereafter. KPMG LLP are the auditors of the Corporation and have confirmed that they are independent with respect to the Corporation within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to the Corporation under all relevant United States professional and regulatory standards.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of the Corporation or of any associate or affiliate of the Corporation.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Bellatrix is not a party to any legal proceeding nor was it a party to any legal proceeding during the 2016 financial year, nor is Bellatrix aware of any contemplated legal proceeding involving Bellatrix, its subsidiaries or any of its property which involves a claim for damages exclusive of interest and costs that may exceed 10% of the current assets of Bellatrix.

During the year ended December 31, 2016, there were no: (i) penalties or sanctions imposed against the Corporation by a court relating to securities legislation or by a securities regulatory authority; (ii) penalties or sanctions imposed by a court or regulatory body against the Corporation that would likely be considered important to a reasonable investor in making an investment decision, or (iii) settlement agreements the Corporation entered into before a court relating to securities legislation or with a securities regulatory authority.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business (unless otherwise required by applicable securities requirements to be disclosed), the only material contracts that the Corporation has entered into within the last financial year, or before the last financial year which are still in effect, which can be reasonably regarded as presently material are the Senior Notes Indenture (see "*Borrowings – Senior Notes*"), the Credit Facilities (see "*Borrowings – Credit Facilities*"), and the Debenture Indenture (see "*Borrowings – Convertible Debentures*"). A copy of the Senior Note Indenture, Credit Facilities and the Debenture Indenture may be viewed on the SEDAR website at www.sedar.com.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Bellatrix are KPMG LLP, Chartered Professional Accountants, Suite 2700, 205 - 5th Avenue S.W., Calgary, Alberta T2P 4B9.

Computershare Trust Company of Canada, at its principal offices in Calgary, Alberta and Toronto, Ontario is the transfer agent and registrar of the Common Shares. The co-transfer agent and registrar for the Common Shares in the United States is Computershare Investor Services US at its principal office in Golden, Colorado.

ADDITIONAL INFORMATION

Additional information relating to the Corporation can be found on SEDAR at www.sedar.com, on EDGAR at www.sec.gov and on our website at www.bellatrixexploration.com.

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular for the Corporation's most recent annual meeting of securityholders that involved the election of directors. Additional financial information is contained in the Corporation's financial statements and the related management's discussion and analysis for the Corporation's most recently completed financial year. For copies of our information circular, our comparative financial statements, including any interim comparative financial statements and additional copies of the Annual Information Form please contact:

Bellatrix Exploration Ltd.
Suite 1920, 800 - 5th Avenue S.W.
Calgary, Alberta T2P 3T6
Tel: (403) 266-8670
Fax: (403) 264-8163

APPENDIX "A"
FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Bellatrix Exploration Ltd. (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data.

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

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company'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 of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

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

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

(c) the content and filing of this report.

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

DATED as of this 17th day of March, 2017.

(signed) "*Brent A. Eshleman*"
Brent A. Eshleman, P.Eng.
President and Chief Executive Officer

(signed) "*Edward J. Brown*"
Edward J. Brown, CPA, CA
Executive Vice-President, Finance and Chief Financial Officer

(signed) "*Murray B. Todd*"
Murray B. Todd
Director

(signed) "*Murray L. Cobbe*"
Murray L. Cobbe
Director

APPENDIX "B"
FORM 51-101F2
REPORT ON RESERVES DATA
BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Bellatrix Exploration Ltd. (the “Company”):

1. We have evaluated the Company’s reserves data as at December 31, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of 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 the Company evaluated for the year ended December 31, 2016, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company’s management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation	Location of Reserves (Country)	Net Present Value of Future Net Revenue ($ thousands CDN - before income taxes, 10% discount rate)			
			Audited	Evaluated	Reviewed	Total
InSite Petroleum Consultants Ltd.	December 31, 2016	Canada	Nil	1,555,554.4	Nil	1,555,554.4

6. 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 audit or evaluate.

7. We have no responsibility to update our report referred to in paragraph 5 for events and circumstances occurring after the effective date of our report, entitled “Evaluation of the P&NG Reserves of Bellatrix Exploration Ltd. (As of December 31, 2016)”.

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

Executed as to our report referred to above:

InSite Petroleum Consultants Ltd.

Calgary, Alberta

Execution Date: March 7, 2017

(signed) "*Peter P. Hadala*"
Peter P. Hadala, P.Eng.
President & Managing Director

(signed) "*Ron Bojechko*"
Ron Bojechko, P.Eng.
Managing Director

(signed) "*Larry K. Lindstrom*"
Larry K. Lindstrom, P.Eng.
Managing Director

APPENDIX "C"
MANDATE AND TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the board of directors (the "**Board**") of Bellatrix Exploration Ltd. ("**Bellatrix**" or the "**Corporation**") to which the Board has delegated its responsibility for the oversight of the following:

1. the nature and scope of the annual audit;

2. the oversight of management's reporting on internal accounting standards and practices;

3. the review of financial information, accounting systems and procedures including internal control over financial reporting;

4. the Corporation's compliance with legal and regulatory requirements;

5. the performance of the Corporation's internal audit function, if any;

6. the qualifications, independence and performance of the Corporation's external auditors; and

7. the quality and integrity of the Corporation's financial reporting and financial statements,

and has charged the Committee with the responsibility of recommending, for approval of the Board, the audited financial statements, interim financial statements and other mandatory disclosure releases containing financial information.

The primary objectives of the Committee are as follows:

1. To assist directors of Bellatrix ("**Directors**") in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of the Corporation and related matters;

2. To oversee the accounting and financial reporting processes of Bellatrix and the audits of Bellatrix's financial statements;

3. To provide better communication between Directors and external auditors;

4. To review and enhance the external auditors' independence;

5. To increase the credibility and objectivity of financial reports; and

6. To strengthen the role of the outside Directors by facilitating in depth discussions between Directors on the Committee, management of Bellatrix ("**Management**") and external auditors.

The Committee, in its capacity as a committee of the Board and subject to the rights of shareholders of Bellatrix and applicable law, is directly responsible for overseeing the relationship of the external auditors with Bellatrix, including the appointment, termination, compensation, retention and oversight of the work of the external auditors engaged by Bellatrix (including resolution of disagreements or disputes between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for Bellatrix.

The external auditors will report directly to the Committee.

Membership of Committee

1. The Committee will be comprised of at least three (3) Directors or such greater number as the Board may determine from time to time and all members of the Committee shall qualify as independent for purposes of (a) National Instrument 52-110 — *Audit Committees* ("**NI 52-110**") (unless the Board determines that an exemption contained in NI 52-110 is available and determines to rely thereon); (b) the rules of the New York Stock Exchange; and (c) Rule 10A-3 ("**Rule 10A-3**") under the United States *Securities Exchange Act of 1934*, as amended, (the "**1934 Act**") (unless the Board determines that an exemption contained in Rule 10A-3 is available and determines to rely thereon).

2. No member of the Committee shall have participated in the preparation of the financial statements of Bellatrix or any current subsidiary of Bellatrix at any time during the prior three years.

3. At least one member of the Committee shall be an "audit committee financial expert" within the meaning of that term under the 1934 Act and the rules adopted by the United States Securities and Exchange Commission (the "**SEC**") thereunder, unless the Board determines that the Committee shall not include an audit committee financial expert and provides the necessary disclosure with respect to such determination as required under the 1934 Act and the rules of the SEC thereunder. If at least one member of the Committee is not determined to be an audit committee financial expert then at least one member of the Committee shall have accounting or related financial management expertise, as determined by the Board in this business judgment.

4. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.

5. All of the members of the Committee must be financially literate, as such qualification is interpreted by the Board, and have the ability to read and understand a set of financial statements, including a balance sheet, income statement, and cash flow statement (or such other comparable statements as are required under generally accepted accounting principles), that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Bellatrix's financial statements, and shall meet any other financial literacy requirements for audit committee members that may be imposed from time to time under Canadian or United States securities laws or any applicable stock exchange rules, unless the Board determines that an exemption from such requirements in respect of any particular member is available and determines to rely thereon.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors;

2. Satisfy itself on behalf of the Board with respect to Bellatrix's internal control systems identifying, monitoring and mitigating business risks; and ensuring compliance with legal, ethical and regulatory requirements;

3. Review and discuss with Management all significant commitments and business risks related to such commitments including, without limitation, commitments associated with farm-in agreements, joint-venture agreements, leases, marketing or transportation arrangements or agreements and all other operational or land agreements, contracts or arrangements;

4. Review and discuss with Management and the external auditors the annual and interim financial statements of the Corporation and related management's discussion and analysis ("**MD&A**") prior to their submission to the Board for approval and inclusion in securities law filings. The process should include but not be limited to:

(a) reviewing changes in accounting principles and policies, or in their application, which may have a material impact on the current or future years' financial statements;

(b) reviewing significant accruals, reserves or other significant estimates;

(c) reviewing accounting treatment of unusual or non-recurring transactions;

(d) ascertaining compliance with covenants under loan agreements;

(e) reviewing disclosure requirements for commitments and contingencies;

(f) reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

(g) reviewing unresolved differences between Management and the external auditors;

(h) reviewing the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Corporation; and

(i) obtaining explanations of significant variances with comparative reporting periods;

5. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**"), annual reports filed with the SEC, and all public disclosure containing audited or unaudited financial information (including, without limitation, annual and interim press releases and any other press releases disclosing earnings or financial results) before release and prior to Board approval. The Committee shall meet to review and discuss the financial statements and MD&A with Management and the external auditor. The Committee must be satisfied that adequate procedures are in place for the review of Bellatrix's disclosure of all other financial information and will periodically assess the accuracy of those procedures;

6. Review and discuss earnings releases, as well as financial information and earnings guidance provided by the Corporation to analysts and rating agencies. Such discussion may be done generally, such as discussing the types of information to be disclosed and the type of presentation to be made. The Committee shall pay particular attention to any use of "pro forma" or "adjusted" non-GAAP information.

7. Meet with the external auditors annually prior to commencement of the audit to discuss planning and staffing of the audit;

8. At least annually, obtain and review a report by the external auditors describing: such auditors' internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of such external auditors, or by any inquiry or investigation by governmental or professional authorities, within the preceding five years, respecting one or more independent audits carried out by such external auditors, and any steps taken to deal with any such issues; and (to assess the external auditors' independence) all relationships between the external auditors and the Corporation;

9. Review analyses prepared by Management and/or the external auditors setting forth significant financial reporting issues and judgments made in connection with the preparation of the Corporation's financial statements, including analyses of the effects of alternative GAAP methods on the financial statements;

10. On an annual basis, review and discuss with the external auditors all relationships such auditors have with Bellatrix and its affiliates in order to determine the auditors' independence, including without limitation:

(a) requesting, receiving and reviewing, on a periodic basis but at least annually, a formal written statement, consistent with applicable accounting standards, from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to Bellatrix;

(b) discussing with the external auditors any disclosed relationships or services that may affect the objectivity and independence of the external auditors; and

(c) taking, or recommending that the Board take, appropriate action to oversee the independence of the external auditors and to take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;

11. When there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change;

12. Review and discuss a report from the external auditors, at a minimum once quarterly and generally in conjunction with the review of any audit or review report prepared by the external auditors with respect to the annual or interim financial statements of the Corporation, regarding:

(a) all critical accounting policies and practices to be used;

(b) all alternative treatments of financial information within applicable generally accepted accounting principles that have been discussed with Management, including the ramifications of the use of such alternative disclosures and treatments, and the treatment preferred by the external auditors; and

(c) other material written communications between the external auditors and Management, such as any management letter or schedule of unadjusted differences;

13. Review and pre-approve, subject to any *de minimis* exceptions available under applicable laws, all audit and permitted non-audit services, including the terms thereof and the fees related thereto, to be provided to Bellatrix or its subsidiaries by the external auditors and consider the impact on the independence of such auditors. The Committee may establish detailed policies and procedures for pre-approval of the provision of audit services and permitted non-audit services by the external auditors. To the extent permitted by applicable laws, the Committee may delegate to one or more independent members of the Committee the authority to pre–approve such audit and non–audit services, provided (i) that such delegation must be detailed as to the particular service to be provided, (ii) the Committee's responsibilities may not be delegated to Management of Bellatrix, (iii) the applicable member(s) must report to the Committee at the next scheduled meeting such pre–approval, and (iv) such member(s) comply with such other procedures as may be established by the Committee from time to time;

14. Review and discuss with the external auditors any audit problems or difficulties, including any difficulties encountered in the course of the audit work, restrictions on the scope of the external auditors' activities or on access to requested information, any significant disagreements with Management, and Management's response. The review should include discussion of the responsibilities, budget and staffing of the Corporation's internal audit function (if any);

15. Review major issues regarding accounting principles and financial statement presentations, including any significant changes in the Corporation's selection or application of accounting principles, and major issues as to the adequacy of the Corporation's internal controls and any special audit steps adopted in light of material control deficiencies;

16. Review with the external auditors the disclosures made to the Committee by Bellatrix's Chief Executive Officer and Chief Financial Officer during their certification process. In particular, the Committee shall review with the Chief Executive Officer, Chief Financial Officer and external auditors: (i) all significant deficiencies and material weaknesses in the design or operation of Bellatrix's internal control over financial reporting that could adversely affect Bellatrix's ability to record, process, summarize and report financial information required to be disclosed by Bellatrix in the reports that it files or submits under any applicable Canadian securities laws or the 1934 Act within the required time periods, and (ii) any fraud, whether or not material, that involves Management or other employees who have a significant role in Bellatrix's internal control over financial reporting;

17. Annually discuss with the external auditors whether they have become aware of any illegal acts in the course of the audit of Bellatrix's financial statements;

18. Review with external auditors (and internal auditor if one is appointed by Bellatrix) their assessment, if any, of the internal controls of Bellatrix, their written reports containing recommendations for improvement, and Management's response and follow-up to any identified weaknesses. The Committee will also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of Bellatrix and its subsidiaries;

19. Review and discuss risk assessment and risk management policies and procedures of the Corporation, including discussing the Corporation's major financial and cyber-security risk exposures and the steps Management has taken to monitor and control such exposures (e.g., hedging, litigation and insurance);

20. Establish procedures for:

    (a) the receipt, retention and treatment of complaints received by Bellatrix regarding accounting, internal accounting controls or auditing matters; and

    (b) the confidential, anonymous submission by employees of Bellatrix of concerns regarding questionable accounting or auditing matters;

21. Establish clear hiring policies regarding the hiring by Bellatrix of partners and employees and former partners and employees of the present and former external auditors of the Corporation;

22. Review and evaluate the lead partner of the external auditors;

23. Ensure the rotation of partners on the audit engagement team of the external auditors in accordance with applicable law;

24. Consider whether, in order to assure continuing auditor independence, there should be regular rotation of the external auditors firm;

25. Present its conclusions with respect to the external auditors to the Board;

26. To review and satisfy itself on behalf of the Board that management has adequate procedures in place for reporting and certification under the Extractive Sector Transparency Measures Act (Canada) ("**ESTMA**") when the Corporation is required to comply with ESTMA;

27. Report regularly to the Board;

28. Review periodically, as determined necessary, the Committee's Mandate and Terms of Reference and recommend to the Board and the Corporate Governance Committee of the Board amendments as the Committee believes are necessary or desirable.

The Committee has authority to communicate directly with the internal auditors (if any) and the external auditors of the Corporation. The Committee will also have the authority to investigate any financial activity of Bellatrix. All employees of Bellatrix are to cooperate as requested by the Committee.

The Committee may also retain, at the expense of Bellatrix, persons having special expertise and/or obtain independent professional advice, including, without limitation, independent counsel or other advisors, as the Committee determines is necessary in order for the Committee to carry out its duties.

Bellatrix shall provide, without any further approval of the Board required, for appropriate funding, as determined by the Committee, in its capacity as a committee of the Board, for payment: (i) of compensation to any external auditors engaged for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for Bellatrix, (ii) of compensation to any advisors or other persons employed by the Committee; and (iii) of ordinary administrative expenses of the Committee that are necessary or appropriate in carrying out its duties.

Meetings and Administrative Matters

1. At all meetings of the Committee every resolution 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 will preside at all meetings of the Committee, unless the Chair is not present, in which case the members of the Committee that are present will designate from among such members the Chair for purposes of the meeting.

3. A quorum for meetings of the Committee will be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee will 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 quarterly. Minutes of all meetings of the Committee will be taken. The Chief Financial Officer of Bellatrix will attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Chairman.

5. The Committee shall meet with the external auditors at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditors and the Committee consider appropriate. For certainty, the Committee shall meet separately, periodically with the external auditors.

6. The Committee shall meet separately, periodically, with Management and with the internal auditors (if any) or other personnel responsible for the internal audit function (if any).

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

8. The Committee may invite such officers, directors and employees of the Corporation and its subsidiaries as it sees fit from time to time to attend at meetings of the Committee and assist in the discussion and consideration of the matters being considered by the Committee.

9. Minutes of the Committee will be recorded and maintained and circulated to Directors who are not members of the Committee or otherwise made available at a subsequent meeting of the Board.

10. The Committee may retain persons having special expertise and may obtain independent professional advice to assist in fulfilling its responsibilities at the expense of the Corporation as determined by the Committee.

11. Any members of the Committee may be removed or replaced at any time by the Board and will 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 exists on the Committee, the remaining members may exercise all its powers so long as a quorum remains. Subject to the foregoing, following appointment as a member of the Committee each member will hold such office until the Committee is reconstituted.

12. Any issues arising from these meetings that bear on the relationship between the Board and Management should be communicated to the Chairman of the Board by the Committee Chair.

13. The performance of the Committee shall be evaluated annually by the Corporate Governance Committee of the Board.

March 14, 2017

SCHEDULE "A" OF APPENDIX "C"
DEFINITION OF INDEPENDENT FOR PURPOSES OF
NATIONAL INSTRUMENT 52-110 — *AUDIT COMMITTEES*

As at October 6, 2014

1. Meaning of Independence –

(a) A director is independent if he or she has no direct or indirect material relationship with the issuer.

(b) For the purposes of subsection 1(a), a "material relationship" is a relationship which could, in the view of the issuer's board of directors, be reasonably expected to interfere with the exercise of a member's independent judgment.

(c) Despite subsection 1(b), the following individuals are considered to have a material relationship with an issuer:

(i) an individual who is, or has been within the last three years, an employee or executive officer of the issuer;

(ii) an individual whose immediate family member is, or has been within the last three years, an executive officer of the issuer;

(iii) an individual who:

(A) is a partner of a firm that is the issuer's internal or external auditor,

(B) is an employee of that firm, or

(C) was within the last three years a partner or employee of that firm and personally worked on the issuer's audit within that time;

(iv) an individual whose spouse, minor child or stepchild, or child or stepchild who shares a home with the individual:

(A) is a partner of a firm that is the issuer's internal or external auditor,

(B) is an employee of that firm and participates in its audit, assurance or tax compliance (but not tax planning) practice, or

(C) was within the last three years a partner or employee of that firm and personally worked on the issuer's audit within that time;

(v) an individual who, or whose immediate family member, is or has been within the last three years, an executive officer of an entity if any of the issuer's current executive officers serves or served at that same time on the entity's compensation committee; and

(vi) an individual who received, or whose immediate family member who is employed as an executive officer of the issuer received, more than CDN$75,000 in direct compensation from the issuer during any 12 month period within the last three years.

(d) Despite subsection 1(c), an individual will not be considered to have a material relation-ship with the issuer solely because

(i) he or she had a relationship identified in subsection 1(c) if that relationship ended before March 30, 2004; or

(ii) he or she had a relationship identified in subsection 1(c) by virtue of subsection (8) if that relationship ended before June 30, 2005.

(e) For the purposes of clauses 1(c)(iii) and 1(c)(iv), a partner does not include a fixed income partner whose interest in the firm that is the internal or external auditor is limited to the receipt of fixed amounts of compensation (including deferred compensation) for prior service with that firm if the compensation is not contingent in any way on continued service.

(f) For the purposes of clause 1(c)(vi), direct compensation does not include:

(i) remuneration for acting as a member of the board of directors or of any board committee of the issuer, and

(ii) the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the issuer if the compensation is not contingent in any way on continued service.

(g) Despite subsection 1(c), an individual will not be considered to have a material relation-ship with the issuer solely because the individual or his or her immediate family member

(i) has previously acted as an interim chief executive officer of the issuer, or

(ii) acts, or has previously acted, as a chair or vice-chair of the board of directors or of any board committee of the issuer on a part-time basis.

(h) For the purpose of determination of independence, an issuer includes a subsidiary entity of the issuer and a parent of the issuer.

2. Additional Independence Requirements —

(a) Despite any determination made under paragraph 1 above, an individual who

(i) accepts, directly or indirectly, any consulting, advisory or other compensatory fee from the issuer or any subsidiary entity of the issuer, other than as remuneration for acting in his or her capacity as a member of the board of directors or any board committee, or as a part-time chair or vice-chair of the board or any board committee; or

(ii) is an affiliated entity of the issuer or any of its subsidiary entities,

is considered to have a material relationship with the issuer.

(b) For the purposes of subsection 2(a), the indirect acceptance by an individual of any consulting, advisory or other compensatory fee includes acceptance of a fee by

(i) an individual's spouse, minor child or stepchild, or a child or stepchild who shares the individual's home; or

(ii) an entity in which such individual is a partner, member, an officer such as a managing director occupying a comparable position or executive officer, or occupies a similar position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity) and which provides accounting, consulting, legal, investment banking or financial advisory services to the issuer or any subsidiary entity of the issuer.

(c) For the purposes of subsection 2(a), compensatory fees do not include the receipt of fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the issuer if the compensation is not contingent in any way on continued service.

SCHEDULE "B" OF APPENDIX "C"

DEFINITION OF INDEPENDENT FOR PURPOSES OF THE NEW YORK STOCK EXCHANGE

As at October 6, 2014

For purposes of the independence rules of the New York Stock Exchange and this Schedule B, an "independent director" means a director, other than an executive officer or employee of the company, who meets the criteria contained in Section 303A.02 of the New York Stock Exchange Listed Company Manual and set forth in this Schedule B. In particular, no director qualifies as "independent" unless the company's board of directors affirmatively determines that the director has no material relationship with the company (either directly or as a partner, shareholder or officer of an organization that has a relationship with the company).

In addition, in affirmatively determining the independence of any director who will serve on the compensation committee of the company's board of directors, the board of directors must consider all factors specifically relevant to determining whether a director has a relationship to the company which is material to that director's ability to be independent from management in connection with the duties of a compensation committee member, including, but not limited to: (A) the source of compensation of such director, including any consulting, advisory or other compensatory fee paid by the company to such director; and (B) whether such director is affiliated with the company, a subsidiary of the company or an affiliate of a subsidiary of the company.

For certainty, but without limitation, a director is not independent under the rules of the New York Stock Exchange if:

1. The director is, or has been within the last three years, an employee of the company, or an immediate family member is, or has been within the last three years, an executive officer, of the company, other than prior employment as an interim executive officer.

2. The director has received, or has an immediate family member who has received, during any twelve-month period within the last three years, more than US$120,000 in direct compensation from the company, other than director and committee fees and pension or other forms of deferred compensation for prior service (provided such compensation is not contingent in any way on continued service), other than:

   (a) Compensation received by a director for former service as an interim Chairman or CEO or other executive officer; and

   (b) Compensation received by an immediate family member for service as an employee of the company (other than an executive officer).

3. (A) The director is a current partner or employee of a firm that is the company's internal or external auditor; (B) the director has an immediate family member who is a current partner of such a firm; (C) the director has an immediate family member who is a current employee of such a firm and personally works on the company's audit; or (D) the director or an immediate family member was within the last three years a partner or employee of such a firm and personally worked on the company's audit within that time.

4. The director or an immediate family member is, or has been with the last three years, employed as an executive officer of another company where any of the company's present executive officers at the same time serves or served on that company's compensation committee.

5. The director is a current employee, or an immediate family member is a current executive officer, of a company that has made payments to, or received payments from, the company for property or services in an amount which, in any of the last three fiscal years, exceeds the greater of US$1 million, or 2% of such other company's consolidated gross revenues.

In the Schedule B, an "immediate family member" includes a person's spouse, parents, children, siblings, mothers and fathers-in-law, sons and daughters-in-law, brothers and sisters-in-law, and anyone (other than domestic employees) who shares such person's home. When applying the look-back provisions contained in the foregoing paragraphs and Section 303A.02(b) of the New York Stock Exchange Listed Company Manual, companies need not consider individuals who are no longer immediate family members as a result of legal separation or divorce, or those who have died or become incapacitated.

In addition, references in this Schedule B to the "company" include any parent or subsidiary in a consolidated group with the company or such other company as is relevant to any determination under the independence standards set forth in this Schedule B and Section 303A.02(b) of the New York Stock Exchange Listed Company Manual.

SCHEDULE "C" OF APPENDIX "C"

DEFINITION OF INDEPENDENT FOR PURPOSES OF RULE 10A-3 UNDER THE UNITED STATES *SECURITIES EXCHANGE ACT OF 1934*

As at October 6, 2014

Additional Independence Requirements for purposes of the Audit Committee - Directors will not be considered independent for purposes of membership on the Audit Committee if:

1. The director is an Affiliate of the company or any subsidiary of the company (other than as a result of being a director of the company or such subsidiary);

2. the director is (i) both a director and an employee of an Affiliate of the company or (ii) an officer, general partner or managing member of an Affiliate of the company;

3. the director or his or her spouse, minor child or stepchild, or child or stepchild sharing a home with the director accepts any consulting, advisory or other compensatory fee from the company or any subsidiary of the company, apart from in his or her capacity as a member of the board or of any other committee of the board, and other fixed amounts of compensation under a retirement plan (including deferred compensation) for prior service with the company (provided such compensation is not contingent in any way on continued service); or

4. the director is a partner, member, managing director, officer or person occupying a comparable position (except limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the company) of a firm which provides consulting, legal, accounting, investment banking or financial advisory services to the company or any subsidiary of the company for fees, regardless of whether the director personally provided the services for which the fees are paid.

For the purposes of the above, an "Affiliate" of the company is a person that directly, or indirectly through one or more intermediaries, controls, or is controlled by, or is under common control with, the company, and includes, without limitation, officers of the company, and subsidiaries and sibling companies of the company. Although the determination of a person or entity's status as an Affiliate requires an analysis of all of the applicable facts and circumstances, a person shall not be deemed to be an "Affiliate" of the company if the person is (a) not the beneficial owner, directly or indirectly of more than 10% of any class of voting equity securities of the company and the person is not an officer of the company.