ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2014

March 19, 2015

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ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	1,000 stock tank barrels	MMbtu	million British Thermal Units
Bbls/d	barrels per day	Bcf	billion cubic feet
BOPD	barrels of oil per day	GJ	gigajoule
NGLs	natural gas liquids	GJ/d	gigajoules per day
STB	stock tank barrels	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 Mcf 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, 2014 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	6.290
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:

"**2015 net capital budget**" has the meaning ascribed to such term under the heading "*General Development of our Business – 2015 Capital Budget*";

"**4.75% Debentures**" means the 4.75% convertible unsecured subordinated debentures of the Corporation issued pursuant to a trust indenture dated April 20, 2010 between the Corporation and Computershare Trust Company of Canada;

"**ABCA**" means *Business Corporations Act* (Alberta);

"**Angle**" means Angle Energy Inc.;

"**Angle Arrangement**" means the plan of arrangement completed on December 11, 2013 under the provisions of the ABCA pursuant to an arrangement agreement between Bellatrix and Angle dated October 15, 2013;

"**Angle Debentures**" means the 5.75% convertible unsecured subordinated debentures due January 31, 2016 of Angle;

"**Angle Shares**" means the common shares of Angle;

"**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.;

"**Blaze**" means Blaze Energy Inc.;

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

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

"**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;

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

"**Daewoo**" means Daewoo International Corporation;

"**Devonian**" means Devonian Natural Resources Private Equity Fund;

"**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.;

"**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;

"**Keyera**" means Keyera Partnership;

"**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.;

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

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

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

"**Sproule Report**" means the report of Sproule dated February 27, 2015 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2014;

"**TCA**" means TCA Energy Ltd.;

"**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, 2014.

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, expectations of the number of additional drilling locations resulting from certain acquisitions, expected timing for spending capital associated with certain joint venture arrangements, expected costs and timing of bringing on stream of certain plants and facilities, 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 of 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 exhausted. Additional information on these and other factors that could affect Bellatrix's operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com), 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 is 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, 2014 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, 2012.

Listing on the NYSE MKT

On August 30, 2012, Bellatrix announced that it had filed an Original Listing Application to list the Common Shares on the NYSE MKT. In connection with the filing of the Original Listing Application, Bellatrix filed a Registration Statement on Form 40-F with the SEC. The Common Shares commenced trading on the NYSE MKT on September 24, 2012 under the symbol "BXE".

2012 Asset Acquisitions and Divestitures

On November 15, 2012 (with an effective date of November 1, 2012), Bellatrix acquired prospective Cardium and Spirit River lands and production in the Willesden Green area of Alberta for approximately $21 million. At the time of the acquisition, the assets to be acquired had production capability of approximately 500 BOE/d (32% oil and liquids and 68% natural gas) and included 16 gross (11.95 net) sections of Cardium and Mannville prospective lands in the Ferrier/Willesden Green Cardium resource play. The assets acquired also included a 25% working interest in an operated compressor station and gathering system. As a result of the acquisition, Bellatrix added an additional 25 net Cardium and 4 net Spirit River drilling locations to the Corporation's drilling inventory.

In late 2012, as a result of an ongoing joint venture development program with the O'Chiese First Nations, Bellatrix acquired an additional 11 gross and net sections of Cardium and Spirit River lands at Ferrier. This acquisition added an additional 37 net drilling locations in the Cardium, 9 net drilling locations in the Spirit River, and 66 net drilling locations in the Duvernay formation.

2013 Joint Ventures and Asset Acquisitions and Divestures

Joint Venture with Grafton Energy Co I Ltd.

On June 27, 2013, Bellatrix closed a $122 million joint venture (the "**Grafton Joint Venture**") with Grafton to accelerate development on a portion of Bellatrix's undeveloped land holdings. The Grafton Joint Venture is in Willesden Green and Brazeau areas of West-Central Alberta. Under the terms of the initial agreement, Grafton was to contribute 82%, or $100 million, to the $122 million Grafton Joint Venture to participate in an expected 29 Spirit River and Cardium well program. In the event Bellatrix fails to expend all of the commitment capital within two years of the closing date and if the funding period has not been otherwise terminated before such time in accordance with the terms of the Grafton Joint Venture, Grafton will be entitled to a non-performance payment from the Corporation equal to 0.4 times the unspent capital. Should Grafton fail to fund as required in accordance with the Grafton Joint Venture, Bellatrix shall have the option to terminate the funding period under the Grafton Joint Venture and if it does so, the Corporation will be entitled to a non-funding payment from Grafton equal to 0.2 times of the unpaid commitment capital. In certain circumstances if Bellatrix is in default of its commitments under the Grafton Joint Venture or 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. Under certain circumstances if Grafton fails to fund in accordance with the Grafton Joint Venture, in addition to the non-funding payment, Bellatrix is entitled to elect to acquire Grafton's earned working interest or GORR, as applicable. The value paid under Grafton's put option and the Corporation's call option shall depend on the circumstances and be based on formulas as set out in the Grafton Joint Venture that reference the net present value, discounted at 10%, of the proved plus probable reserves to be acquired, as evaluated by an independent reserves evaluator.

On September 10, 2013, Bellatrix announced that Grafton elected to exercise an option to increase the committed capital investment by an additional $100 million on the same terms and conditions. Under the terms of the amended agreement, Grafton will contribute 82%, or $200 million, to the $244 million Grafton Joint Venture to participate in an expected 58 Spirit River and Cardium well program. Under the agreement, Grafton will earn 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 shall have 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. Under the agreement, Grafton was also granted an additional one-time option to be exercised within 12 months of the effective date to increase its exposure by an additional $50 million on the same terms and conditions. The effective date of the agreement is July 1, 2013 and has a term of 2 years.

Asset Disposition and Strategic Partnership with Daewoo International Corporation and Devonian Natural Resources Private Equity Fund

On September 3, 2013, Bellatrix announced the closing of a $200 million strategic joint venture (the "**Daewoo/Devonian Joint Venture**") and a $52.5 million asset disposition with Daewoo and Devonian whereby Bellatrix sold, effective July 1, 2013, to the Canadian subsidiaries of Daewoo and Devonian an aggregate 50% of the Corporation's working interest share of its producing assets, an operated compressor station and gathering system and related land acreage in the Baptiste area of West Central Alberta for gross consideration of $52.5 million. The Daewoo/Devonian Joint Venture, which was effective as of July 1, 2013, encompasses a multiyear commitment to jointly develop the aforementioned acreage in Ferrier and Willesden Green of West Central Alberta encompassing 70 gross wells with anticipated total capital expenditures to the Daewoo/Devonian Joint Venture of approximately $200 million.

Joint Venture with TCA Energy Ltd.

On November 11, 2013, Bellatrix announced it had closed a $240 million joint venture partnership (the "**TCA Joint Venture**") with TCA. TCA is a Canadian incorporated special purpose vehicle for Troika Resources Private Equity Fund which is based in Seoul, Korea and managed by KDB Bank, SK Energy and Samchully AMC. Pursuant to the agreement forming the TCA Joint Venture, Bellatrix and TCA will drill and develop lands in the Ferrier Cardium area of West Central Alberta, with the program to be completed by December 31, 2014, unless extended by the parties. TCA will contribute $120 million, representing a 50% share, towards the capital program for the drilling of an expected 63 gross wells, and in exchange, will receive 35% of Bellatrix's working interest until payout (being recovery of TCA's capital investment plus a 15% internal rate of return) on the total program, and thereafter reverting to 25% of our working interest. As part of this agreement, TCA participated in 14 gross wells (as included in the total expected 63 gross well program) drilled between January 1, 2013 and November 11, 2013, resulting in net proceeds of $16.7 million that were received by Bellatrix at closing.

2013 Property Acquisition

During the fourth quarter of 2013, the Corporation increased its current working interest in certain Cardium and Spirit River lands and production in the Willesden Green (Baptiste) area of Alberta through the acquisition of additional working interests from several companies for a total combined net purchase price of $10 million.

2013 Redemption of 4.75% Debentures

During the third quarter of 2013, Bellatrix issued a notice of redemption of its then outstanding $55.0 million 4.75% Debentures, with a redemption date of October 21, 2013. During September 2013, $5 million principal amount of 4.75% Debentures were converted into an aggregate of 895,605 Common Shares. Subsequent to September 30, 2013, the remaining $50 million principal amount of 4.75% Debentures were converted or redeemed in exchange for an aggregate of 8,898,243 Common Shares.

2013 Public Offering of Common Shares

On November 5, 2013, Bellatrix closed a bought deal offering of 21,875,000 Common Shares at a price of $8.00 per Common Share for aggregate gross proceeds of approximately $175 million.

2013 Angle Arrangement

On December 11, 2013, Bellatrix closed the Angle Arrangement with Angle, pursuant to which, Bellatrix acquired all of the issued and outstanding Angle Shares and all of the issued and outstanding Angle Debentures. Pursuant to the Angle Arrangement, Bellatrix acquired all of the issued and outstanding Angle Shares for consideration consisting of $69.7 million in cash and approximately 30.2 million Common Shares. The Corporation acquired all of the issued and outstanding Angle Debentures in the aggregate principal amount of $60 million on the basis of $1,040 in cash per $1,000 principal amount of the Angle Debentures, plus accrued and unpaid interest to December 10, 2013. As part of the Angle Arrangement, Angle and its subsidiary, Angle Resources Inc., amalgamated with Bellatrix and continued under the name "Bellatrix Exploration Ltd." and the Angle Shares were delisted from the TSX.

In conjunction with the Angle Arrangement, the Board approved the appointment of Keith Turnbull, a former director of Angle, as a director of Bellatrix effective January 1, 2014.

2014 Joint Ventures and Asset Acquisitions and Divestures

Grafton Joint Venture

On April 10, 2014, Bellatrix announced that Grafton elected to exercise their option to increase their committed capital investment pursuant to the Grafton Joint Venture by an additional $50 million, for a total commitment of $250 million, on the same terms and conditions as described above. Grafton's increased capital investment will continue to support the accelerated development of a portion of the Corporation's undeveloped land holdings. With the exercise of the $50 million option, the Corporation has until the end of the third anniversary of the effective date of the initial agreement for the Grafton Joint Venture (July 1, 2013) to spend the additional capital.

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 will propose development plans for approval by a management committee comprised of representatives of Bellatrix and CNOR. 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). The CNOR Joint Venture funding is available immediately; however, the Corporation expects the funds to be spent primarily from 2016 through 2018. 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. In certain circumstances if the Corporation is in default of its commitments under the CNOR Joint Venture or there is a change of control of Bellatrix, CNOR has the right to cause the Corporation to acquire CNOR's earned working interest or GORR, as applicable. Under certain circumstances if CNOR fails to fund in accordance with the CNOR Joint Venture, in addition to the non-funding payment, the Corporation will be entitled to elect to acquire CNOR's earned working interest or GORR, as applicable.

The value paid under CNOR's put option and Bellatrix's call option will depend on the circumstances and be based on formulas as set out in the CNOR Joint Venture that reference the net present value, discounted at 10%, of the proved plus probable reserves to be acquired, as evaluated by an independent reserves evaluator.

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) 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 arrangement, the Corporation has committed to drill a minimum of 6 wells into the Cardium interval and 6 wells into the Mannville interval. By drilling these wells, Bellatrix 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 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.

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) 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 is 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.

Alder Flats Acquisition

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) 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 Alder Flats Gas Plant

During the fourth quarter of 2014, Bellatrix completed the transfer at cost of minority interests in its O'Chiese Ness-Ohpawganu'ck deep-cut gas plant at Alder Flats (the "**Bellatrix Alder Flats Plant**") and related pipeline infrastructure currently under construction (collectively the "**Facilities**") to Keyera and O'Chiese. Under the agreed upon terms, Keyera and O'Chiese will participate as 35% and 5%, respectively, minority interest owners in the Facilities, which consist of the two proposed phases of the Bellatrix-operated deep-cut gas plant and related plant infrastructure, as well as the associated pipelines, all of which are currently under construction. The Corporation will retain a 60% ownership interest in the Facilities and will be the operator.

The sales gas design capacity of the Bellatrix Alder Flats Plant is 220 MMcf/d and will be developed in two phases at an estimated total cost of approximately $190 million; the total cost of the Facilities which includes the Bellatrix Alder Flats Plant and related infrastructure is estimated at $230 million. As at December 31, 2014, approximately $60 million had been spent on Phase I of the Bellatrix Alder Flats Plant including the interests of Keyera and O'Chiese. Phase I of the new Bellatrix Alder Flats Plant has an expected on-stream date of July 1, 2015 and Phase II of the new Bellatrix Alder Flats Plant has an expected on-stream date in 2017.

2014 Pipeline Completion

On April 2, 2014, the Corporation announced the completion of a 1.6 km river bore and a 7 km pipeline in conjunction with the completion by Blaze of a 55 km pipeline to tie-in Bellatrix's natural gas for processing in the Blaze gas plant located at 04-31-048-12W5. The Corporation has secured firm processing capacity of 100 MMcf/d in the plant. The pipeline was commissioned on April 1, 2014. In the fourth quarter of 2013 and in the first quarter of 2014, Bellatrix installed a total of 8 field booster compressors located at 13-5-45-9W5 (tie-in point to the Blaze pipeline) with capacity of 97 MMcf/d.

2014 Plant Turnarounds

On May 16, 2014, the Corporation announced that during the month of May it was experiencing significant unscheduled temporary plant turnarounds at some of the third party operated gas processing plants where some of the Corporation's production from west central Alberta is processed. Although the Corporation made every effort to redirect and offload gas to alternative plants during these outages, the cumulative impact of the unscheduled temporary plant turnarounds was a reduction of 4,064 BOE/d in the Corporation's May net average production volumes.

2014 Firm Processing Agreement

On December 2, 2014, the Corporation announced that it has entered into an agreement with Keyera for 19 MMcf/d of firm service processing capacity beginning immediately, 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 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 Increased Credit Facilities and 2015 Financial Covenants Amendment

On December 1, 2014, the lenders under the Credit Facilities increased the Corporation's borrowing base under the Credit Facilities to $725 million from $625 million. The increased Credit Facilities are available to finance the Corporation's ongoing capital expenditures, working capital requirements, and for general corporate purposes. The Corporation is required to comply with covenants under its Credit Facilities, which include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding. As a result of the recent precipitous drop in crude oil prices and the concomitant reduction in Bellatrix's associated future cash flow and EBITDA, the Corporation sought and obtained from its lenders temporary relaxation of certain of the financial covenants under the Credit Facilities. For additional information relating to the Credit Facilities, see "*Borrowings*".

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 provided that Orange Capital (or its affiliates) owns, controls or directs, directly or indirectly 10% or more of the outstanding Common Shares. Orange Capital is only entitled to one nominee if its percentage ownership falls below 10% but remains above 5% of the outstanding Common Shares. In addition, to the standstill provision, Orange Capital has agreed to cause all Common Shares that it or its affiliates are entitled to vote, to be voted in favour of all the management nominees for election as directors of the Corporation and in favour of the resolution approving and authorizing all unallocated options to purchase Common Shares granted under the Corporation's share option plan at the 2015 annual shareholders meeting of the Corporation. A copy of the agreement with Orange Capital is filed on SEDAR at www.sedar.com.

2015 Capital Budget

On November 4, 2014, the Corporation announced an initial $450 million net capital budget for 2015 (the "**2015 net capital budget**"), which was reduced to $400 million on December 1, 2014 in light of recent commodity price changes. On December 22, 2014, the Corporation announced a reduction of the 2015 net capital budget to $300 million in light of rapid declines in crude oil prices. On January 29, 2015, in response to continued volatility of oil and gas prices, the Corporation announced an updated 2015 net capital budget of up to $200 million, reduced from the previously approved $300 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 pursued 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 strong 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 is expected 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*".

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 February 27, 2015. The effective date of the Statement is December 31, 2014 and the preparation date of the Statement is February 27, 2015.

Disclosure of Reserves Data

The reserves data set forth below (the "**Reserves Data**") is based upon an evaluation by Sproule with an effective date of December 31, 2014. 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 Sproule 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, 2014
FORECAST PRICES AND COSTS**

	Light And Medium Oil		Heavy Oil		Natural Gas[1]		Natural Gas Liquids	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**
Proved Developed Producing	9,008.8	7,305.4	23.9	21.2	291,764	237,063	16,356.0	10,958.6
Proved Developed Non-Producing	203.7	175.4	77.0	59.1	6,373	5,419	304.4	205.1
Proved Undeveloped	7,866.9	6,525.1	108.9	81.2	356,650	296,978	17,508.0	12,849.9
Total Proved	17,079.4	14,005.9	209.8	161.5	654,787	539,460	34,168.4	24,013.5
Probable	7,720.6	6,129.4	213.7	155.1	357,626	288,774	20,738.2	14,744.3
Total Proved Plus Probable	24,800.0	20,135.3	423.5	316.6	1,012,413	828,234	54,906.6	38,757.8

Note:

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

	Net Present Values of Future Net Revenue											
	Before Income Taxes Discounted At (%/year)					**After Income Taxes Discounted at (%/year)**					**Unit Value Before Income Tax Discounted at 10% Year[1]**	
Reserves Category	**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	1,562,159	1,162,721	932,046	782,872	678,792	1,562,159	1,162,721	932,046	782,872	678,792	16.13	2.69
Proved Developed Non–Producing	27,463	21,785	17,872	15,064	12,976	27,463	21,785	17,872	15,064	12,976	13.31	2.22
Proved Undeveloped	1,346,355	768,248	461,602	279,377	162,344	1,018,812	594,238	360,220	216,319	121,175	6.69	1.12
Total Proved	2,935,976	1,952,754	1,411,520	1,077,313	854,112	2,608,434	1,778,744	1,310,138	1,014,255	812,943	11.02	1.84
Probable	1,817,319	1,067,708	704,085	496,725	365,370	1,362,632	796,728	521,876	365,112	265,818	10.18	1.70
Total Proved Plus Probable	4,753,295	3,020,462	2,115,605	1,574,039	1,219,481	3,971,066	2,575,472	1,832,014	1,379,367	1,078,761	10.73	1.79

Note:

(1) Unit values are based upon net reserves.

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

Reserves Category	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Capital Development Costs ($000s)	Abandonment Costs ($000s)	Future Net Revenue Before Income Taxes ($000s)	Income Tax ($000s)	Future Net Revenue After Income Taxes ($000s)
Proved Reserves	7,486,353	1,548,969	2,050,750	863,249	87,410	2,935,976	327,543	2,608,434
Proved Plus Probable	11,811,840	2,509,849	3,100,103	1,335,990	112,603	4,753,295	782,229	3,971,066

FUTURE NET REVENUE
BY PRODUCTION GROUP[(1)]
AS OF DECEMBER 31, 2014
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)	501,142	$13.09/BOE
	Heavy Oil (including solution gas and other by-products)	2,129	$13.18/BOE
	Natural Gas (including by–products but excluding solution gas from oil wells)[(3)]	879,811	$9.81/BOE
	Other[(4)]	28,438	
	Total	1,411,520	
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	732,299	$13.05/BOE
	Heavy Oil (including solution gas and other by-products)	4,426	$13.98/BOE
	Natural Gas (including by–products but excluding solution gas from oil wells)[(3)]	1,345,247	$9.55/BOE
	Other[(4)]	33,633	
	Total	2,115,605	

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.
(3) Includes minor amounts of revenue and costs associated with natural gas from coal bed methane and shale gas reserves.
(4) Other is rebated costs from company transportation and processing of royalty volumes, primarily those of the Alberta Crown, denoted as Gas Cost Allowance ("**GCA**").

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 Sproule 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;
- Specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed; and
- A remaining reserve life of 50 years.

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 quantitative 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 55.3 of the COGE Handbook.

3. Well abandonment and disconnect costs were estimated and included in the Sproule Report at the individual entity level for all wells that were assigned reserves (including future wells to be drilled). No allowance for surface lease reclamation and salvage value was included. No abandonment costs have been estimated for suspended wells, gathering systems, batteries, plants or processing facilities.

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 assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil and natural gas benchmark reference pricing, inflation and exchange rates utilized by Sproule in the Sproule Report were an average of forecast prices and costs published by Sproule, GLJ Petroleum Consultants Ltd., and McDaniel & Associates Consultants Ltd. as at December 31, 2014, which are as follows:

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						
2015	67.89	57.48	3.38	73.48	1.833	0.85
2016	83.52	70.74	3.83	90.17	1.833	0.87
2017	90.96	77.07	4.06	98.20	1.833	0.87
2018	95.26	80.70	4.41	102.69	1.833	0.87
2019	99.33	84.12	4.76	106.99	1.833	0.87
2020	103.80	87.87	4.97	111.73	1.833	0.87
2021	106.16	89.88	5.18	114.26	1.833	0.87
2022	108.10	91.53	5.36	116.34	1.833	0.87
2023	110.09	93.19	5.54	118.47	1.833	0.87
2024	112.13	94.91	5.70	120.67	1.833	0.87
Thereafter	+1.83%/yr	+1.83%/yr	+1.83%/yr	+1.83%/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.

Weighted average historical prices realized by Bellatrix (before commodity price risk management contracts) for the year ended December 31, 2014, were $4.77/Mcf for natural gas, $91.41/Bbl for light and medium gravity crude oil and condensate, and $42.74/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, 2013 compared to December 31, 2014 based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM OIL: Company Gross Proved (Mbbl)	LIGHT AND MEDIUM OIL: Company Gross Probable (Mbbl)	LIGHT AND MEDIUM OIL: Company Gross Proved Plus Probable (Mbbl)	HEAVY OIL: Company Gross Proved (Mbbl)	HEAVY OIL: Company Gross Probable (Mbbl)	HEAVY OIL: Company Gross Proved Plus Probable (Mbbl)
December 31, 2013(2)	18,993.1	11,568.1	30,561.2	216.8	264.9	481.7
Discoveries	57.0	10.5	67.5	-	-	-
Extensions	482.9	601.6	1,084.5	-	-	-
Infill Drilling	749.6	794.4	1,544.0	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(1,715.5)	(5,120.5)	(6,836.0)	19.5	(51.2)	(31.7)
Acquisitions	420.6	173.4	594.0	-	-	-
Dispositions	(203.0)	(38.4)	(241.4)	-	-	-
Economic Factors	(12.2)	(268.5)	(280.7)	(0.9)	-	(0.9)
Production	(1,693.1)	-	(1,693.1)	(25.6)	-	(25.6)
December 31, 2014(3)	17,079.4	7,720.6	24,800.0	209.8	213.7	423.5

FACTORS	NATURAL GAS LIQUIDS Company Gross Proved (Mbbl)	NATURAL GAS LIQUIDS Company Gross Probable (Mbbl)	NATURAL GAS LIQUIDS Company Gross Proved Plus Probable (Mbbl)	NATURAL GAS[1] Company Gross Proved (MMcf)	NATURAL GAS[1] Company Gross Probable (MMcf)	NATURAL GAS[1] Company Gross Proved Plus Probable (MMcf)
December 31, 2013[2]	25,841.9	21,194.8	47,036.7	474,353	326,065	800,418
Discoveries	42.6	8.8	51.4	1,042	216	1,258
Extensions	1,294.5	1,138.5	2,433.0	28,324	24,394	52,718
Infill Drilling	2,678.4	1,826.0	4,504.4	60,793	40,173	100,966
Improved Recovery	-	-	-	-	-	-
Technical Revisions	4,544.5	(3,633.0)	911.5	67,307	(66,715)	592
Acquisitions	4,731.5	1,803.2	6,534.7	109,660	41,797	151,457
Dispositions	(793.5)	(182.6)	(976.1)	(17,844)	(4,125)	(21,968)
Economic Factors	(1,342.5)	(1,417.5)	(2,760.0)	(12,876)	(4,180)	(17,055)
Production	(2,829.0)	-	(2,829.0)	(55,972)	-	(55,972)
December 31, 2014[3]	34,168.4	20,738.2	54,906.6	654,787	357,626	1,012,413

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 4, 2014 and effective as of December 31, 2013.
(3) As evaluated in the Sproule Report.

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, 2014, 2013 and 2012 and, in the aggregate, before that time based on forecast prices and costs.

Proved Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		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
Prior thereto	2,552.3	4,425.1	30.0	210.0	49,804	84,812	1,919.4	3,250.4
2012	1,123.7	5,118.5	-	113.3	36,227	120,898	1,495.7	5,199.7
2013	1,430.3	9,481.3	-	112.8	123,060	275,557	5,186.4	13,774.2
2014	796.5	7,866.9	-	108.9	33,762	356,650	1,549.6	17,508.0

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		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
Prior thereto	2,923.6	3,457.6	5.0	120.0	46,531	65,527	1,843.0	2,654.8
2012	1,619.5	3,858.8	-	199.8	81,223	163,856	4,921.7	7,003.1
2013	2,593.5	8,327.7	-	198.7	116,455	259,669	5,386.1	17,251.5
2014	1,317.9	5,434.6	-	187.0	50,976	276,565	2,367.5	16,324.1

Note:

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

Proved Undeveloped Reserves

A total of 356,650 MMcf of natural gas, 7,975.8 Mbbl of oil and 17,508.0 Mbbl of NGLs were assigned as proved undeveloped reserves as at December 31, 2014, representing approximately 53% 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, Sproule 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 2015 and 2018. With respect to capital development costs associated with proved undeveloped reserves in the Sproule Report, approximately 66% of the capital is scheduled to be spent over the next two years and 90% is scheduled to be spent over the next three 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, Harmattan and Strachan and represents 81% 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 and Frog Lake. The majority of this spending is also forecast for the next three 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 indicated 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 2015 net capital budget.

Probable Undeveloped Reserves

A total of 276,565 MMcf of natural gas, 5,621.6 Mbbl of oil and 16,324.1 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2014, representing approximately 77% of our total probable reserves or 27% 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 proved 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 2015 to 2018. With respect to capital development costs associated with probable undeveloped reserves in the Sproule Report, approximately 70% of the capital is scheduled to be spent over the next two years and 92% is scheduled to be spent over the next three 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 as indicated 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 2015 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)**
2015	234,209	369,262
2016	339,453	532,991
2017	203,473	309,953
2018	85,377	123,046
2019	-	-
Thereafter	736	736
Total: Undiscounted	863,249	1,335,990

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, 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 – 2015 Capital Budget*", as a result of continued depressed and volatile oil and gas prices, the Board reduced the 2015 net capital budget to $200 million. As a result, the 2015 net capital budget would not meet the development schedule as contemplated by the Sproule Report. The Corporation continues to monitor commodity prices and may make further changes (either positive or negative) to the 2015 net capital budget. As a result, the reserves as set out in the Sproule Report may not be developed as quickly as contemplated by the Sproule 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, 2014. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2014 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. Area production averaged 22,655 BOE/d for 2014, comprised of 80% natural gas, 13% natural gas liquids and 7% 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. Gas volumes from the area are 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 65,834 gross (37,589 net) acres of developed land and 46,072 gross (37,745 net) acres of undeveloped land as at December 31, 2014.

In 2014, Bellatrix operated the drilling of 58 gross (31.6 net) Cardium horizontal oil and liquids-rich gas wells; the Corporation also participated in 1 gross (0.3 net) non-operated Cardium test well. The Corporation also drilled 30 gross (14.0 net) Spirit River liquids-rich gas wells and participated in an additional 2 gross (0.7 net) non-operated Spirit River gas wells.

In September 2014, the Corporation completed a tuck-in acquisition of working-interests at Ferrier, extending its Cardium light oil resource play. The acquired assets have a low decline rate with net production of approximately 300 BOE/d (24% oil and liquids and 76% natural gas) which 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 of Cardium rights at Ferrier. Under the arrangement, Bellatrix has committed to drill a minimum of 6 wells into the Cardium interval and 6 wells into the Mannville interval. By drilling these wells, the Corporation 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 farmor. 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.

In late November 2014, the Corporation closed an acquisition of complementary working interests at Ferrier, focused on the liquids rich Mannville natural gas play, for total cash consideration of approximately $118 million. The acquisition added approximately 2,200 boe/d of currently unrestricted production (80% natural gas, 20% liquids), and largely represents the consolidation of working interest ownership from existing wellbores and Mannville formation rights in Alder Flats.

During the fourth quarter of 2014, the Corporation completed the acquisition of complementary assets within the greater Ferrier region for total adjusted cash consideration of $33.0 million. Approximately 720 boe/d of unrestricted production (77% natural gas, 23% liquids) 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 is 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.

Although Bellatrix continues to monitor the emerging Duvernay resource play at Ferrier, the Corporation did not drill any Duvernay wells in 2014.

To date in 2015 at Ferrier, the Corporation has drilled a total of 2 gross (1.1 net) Cardium horizontal wells, which have been completed and tied-in. The Corporation has drilled 3 gross (2.0 net) Spirit River horizontal gas wells, of which all have been completed, tied in and placed on production.

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 1,898 BOE/d for 2014, consisting of 62% natural gas, 24% light oil and 14% natural gas liquids. The majority of this production is operated. The Corporation owns and operates three compressor stations in the area with working interests ranging from 46.86% to 84.75%. Gas is delivered to a third party operated gas plant where Bellatrix holds a minority interest for processing. The Corporation held 35,680 gross (18,041 net) acres of developed land and 9,120 gross (4,839 net) acres of undeveloped land as at December 31, 2014.

Bellatrix drilled and tied-in 5 gross (2.4 net) Cardium oil wells at Willesden Green in 2014. Bellatrix also participated in the drill and tie-in of 2 gross (0.4 net) non-operated Cardium horizontal oil wells. In addition, Bellatrix drilled a successful Spirit River horizontal liquids rich gas well (0.6 net), which was completed and tied-in.

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 1,928 BOE/d for 2014, consisting of 26% natural gas, 68% light oil and condensate and 6% natural gas liquids. Oil production from the area is delivered to Bellatrix owned and operated oil batteries and gas production is delivered to third party non-operated gas plant for processing. The Corporation held 58,747 gross (34,027 net) acres of developed land and 15,372 gross (6,495 net) acres of undeveloped land as at December 31, 2014.

In 2014, Bellatrix operated the drill and tie-in of 6 gross (5.0 net) Cardium oil wells in the Greater Pembina area. In addition, the Corporation drilled 1 gross (0.5 net) successful horizontal well into the Lower Mannville Ellerslie formation, which was completed and tied in.

To date in 2015, the Corporation participated in one non-operated Cardium oil well (0.2 net); the well has been tied in and is on production.

Strachan

Strachan is located approximately 12 kilometres south of Rocky Mountain House, Alberta. Bellatrix acquired the Strachan property pursuant to the Angle Arrangement in December 2013. 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 1,715 BOE/d for 2014, consisting of 49% light oil and condensate, 23% natural gas and 28% natural gas liquids. As at December 31, 2014, the Corporation owned and operated four facilities and had a 100% working interest in two compressor stations and a 64.75% working interest and 50.25% working interest in two other compressor stations. All gas production volumes are delivered on to a third party non-operated gas plant for processing. Bellatrix held 23,203 gross (14,822 net) acres of developed land and 46,319 gross (35,928 net) acres of undeveloped land as at December 31, 2014.

In 2014, Bellatrix operated the drill and tie-in of 3 gross (3.0 net) Cardium oil wells at Strachan. To date in 2015, Bellatrix has not drilled additional Cardium wells at Strachan.

Harmattan

Harmattan is located approximately 80 kilometres northwest of Calgary near the town of Sundre, Alberta. Bellatrix acquired the Harmattan property pursuant to the Angle Arrangement in December 2013. This property produces oil and associated natural gas from the Cardium and Viking zones and liquids-rich natural gas from zones in the Lower Mannville and Rock Creek formations at depths of 1,200 to 2,600 metres. Production from this property averaged 4,950 BOE/d for 2014, consisting of 39% natural gas, 24% light oil and condensate and 37% natural gas liquids. The majority of the production from the area is operated by Bellatrix. The Corporation owns a 100% working interest in a large oil battery and a compressor station where a majority of oil volumes are handled. All gas is delivered to a third party non-operated gas plant for processing. Bellatrix held 35,764 gross (33,163 net) acres of developed land and 68,390 gross (67,230 net) acres of undeveloped land as at December 31, 2014.

Management believes that current mapping supports very strong potential for resource development of the oil and liquids rich gas reserves in the Lower Mannville and, although management considers the results of drilling in the

Lower Mannville at Harmattan and Davey Lake to be encouraging, they believe there is potential to improve netbacks from this play.

In 2014, Bellatrix drilled and completed 1 gross (0.5 net) horizontal well into the Lower Mannville Ellerslie formation to test the liquids-rich gas potential, using revised drill and completion techniques. The well has been tied in and is currently being monitored for production performance after applying updated completion techniques.

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, 2014.

	Oil Wells				Natural Gas Wells			
	Producing		Non-Producing		Producing		Non-Producing	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	419	251	115	47	845	455	168	120
Saskatchewan	3	-	1	1	13	13	21	20
British Columbia	-	-	2	1	7	1	7	2
Total	422	251	118	49	865	469	196	142

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2014.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Alberta	462,741	282,478	405,991	330,835	868,732	613,313
British Columbia	9,285	2,765	106,180	47,208	115,465	49,973
Saskatchewan	13,327	12,720	7,641	7,641	20,968	20,361
Total	485,353	297,962	519,812	385,685	1,005,165	683,647

Note:

(1) May not add due to rounding.

The following provides details of certain of the Corporation's drilling commitments as at December 31, 2014:

- Bellatrix committed to drill 10 gross (4.4 net) wells pursuant to farm-in agreements as at December 31, 2014. Bellatrix expects to satisfy these drilling commitments at an estimated net cost of approximately $16.7 million.

- Pursuant to a joint venture agreement dated February 1, 2011, Bellatrix is committed to drilling 3 gross (3.0 net) wells per year between 2011 and 2015 for a total estimated cost of approximately $56.3 million. As at December 31, 2014, 3 wells remained to be drilled under this commitment for a total estimated cost of $11.3 million.

- Pursuant to a joint venture agreement dated August 4, 2011, Bellatrix is committed to drilling 5 to 10 gross and net wells per year between 2011 and 2016 for a total of 40 gross and net wells at an estimated cost of approximately $150.0 million. As at December 31, 2014, 1 well remained to be drilled under this commitment for a total estimated cost of $3.8 million.

- Pursuant to a joint venture agreement dated December 14, 2012, Bellatrix is committed to drilling 2 gross and net wells per year between 2014 and 2018 for a total of 10 gross and net wells at an estimated cost of approximately $37.5 million. As at December 31, 2014, 1 well remained to be drilled under this commitment for a total estimated cost of $3.8 million.

Potentially, approximately 13% of our mineral rights are under review prior to December 31, 2015 as a result of those rights reaching the end of their initial land tenure or Indian Oil and Gas Canada administrated rights being subject to a standard, cyclic review process. For any of these rights deemed not already capable of production, Bellatrix plans to evaluate and identify potential drilling operations on selected portions of these lands, to be tested prior to expiry to preserve the rights, and/or to submit applications to continue that acreage.

In addition to the above noted drilling commitments the Corporation entered into a number of joint venture agreements in 2013 and 2014 as described under the heading "*General Development of our Business* ".

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 and natural gas production. We hedged an average of 49% of total crude oil and natural gas liquids production and an average of 60% of total natural gas production during the twelve months ended December 31, 2014. The following provides details of the commodity price risk management arrangements outstanding as at December 31, 2014 and as of the date hereof.

As at December 31, 2014, the Corporation had not entered into commodity price risk management arrangements.

Subsequent to December 31, 2014, the Corporation has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Crude oil fixed	February 1, 2015 to Dec. 31, 2015	2,000 bbl/d	$ 70.27 CDN	$ 70.27 CDN	WTI
Crude oil fixed	February 1, 2015 to Dec. 31, 2015	1,000 bbl/d	$ 70.48 CDN	$ 70.48 CDN	WTI
Natural gas fixed	March 1, 2015 to March 31, 2015	25,000 GJ/d	$ 2.83 CDN	$ 2.83 CDN	AECO
Natural gas fixed	March 1, 2015 to March 31, 2015	25,000 GJ/d	$ 2.81 CDN	$ 2.81 CDN	AECO
Natural gas fixed	March 1, 2015 to March 31, 2015	25,000 GJ/d	$ 2.83 CDN	$ 2.83 CDN	AECO
Natural gas fixed	March 1, 2015 to March 31, 2015	25,000 GJ/d	$ 2.82 CDN	$ 2.82 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	20,000 GJ/d	$ 2.50 CDN	$ 2.50 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	20,000 GJ/d	$ 2.50 CDN	$ 2.50 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	2,500 GJ/d	$ 2.53 CDN	$ 2.53 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	15,000 GJ/d	$ 2.50 CDN	$ 2.50 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	5,000 GJ/d	$ 2.80 CDN	$ 2.80 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	20,000 GJ/d	$ 2.53 CDN	$ 2.53 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	10,000 GJ/d	$ 2.54 CDN	$ 2.54 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	10,000 GJ/d	$ 2.59 CDN	$ 2.59 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	10,000 GJ/d	$ 2.59 CDN	$ 2.59 CDN	AECO
Natural gas fixed	April 1, 2015 to Oct. 31, 2015	10,000 GJ/d	$ 2.58 CDN	$ 2.58 CDN	AECO
Natural gas fixed	March 1, 2015 to Dec. 31, 2015	20,000 GJ/d	$ 2.56 CDN	$ 2.56 CDN	AECO
Natural gas fixed	March 1, 2015 to Dec. 31, 2015	20,000 GJ/d	$ 2.58 CDN	$ 2.58 CDN	AECO

Natural gas fixed	March 1, 2015 to Dec. 31, 2015	17,500 GJ/d	$ 2.56 CDN	$ 2.56 CDN	AECO

Additional Information Concerning Abandonment and Reclamation Costs

Well abandonment and disconnect costs were estimated and included in the Sproule Report at the individual entity level for all wells that were assigned reserves (including future wells to be drilled). We use our historical cost information on an area by area basis as the means for estimating the future abandonment costs. When this information is not available, the estimate is determined with reference to appropriate regulatory standards and requirements. Additional abandonment and reclamation costs associated with non-reserves wells, reclamation costs for wells with reserves and facility abandonment and reclamation expenses have not been included in the Sproule Report analysis.

In the Sproule Report, the number of existing and future net oil and gas wells for which revenues and costs are forecast, including future well abandonment costs, varies by year depending on when wells commence and end production. The total amount of such costs, all of which is deducted in the calculation of future net revenue from proved and proved plus probable reserves report is $87.4 million ($14.1 million discounted at 10%) and $112.6 million ($12.6 million discounted at 10%), respectively. In the next three financial years, these costs are as follows:

Year	Total Proved ($000's)	Total Proved Plus Probable ($000's)
2015	54	20
2016	384	192
2017	921	439
Subtotal	1,359	651
Remainder	86,051	111,952
Total (Undiscounted)	87,410	112,603
Total discounted at 10%	14,100	12,599

We currently have 1,271 net wells for which we expect to incur abandonment and reclamation costs. This includes some wells which have not been included in Sproule's calculation of abandonment costs where no reserves are attributable. At December 31, 2014, the estimated total undiscounted amount required to settle the asset retirement obligations (being abandonment and reclamation costs for net producing and shut in wells and facilities) of the Corporation was approximately $147.9 million, of which $88.6 million has been recorded in the Corporation's financial statements for the year ended December 31, 2014. The incremental costs for future site restoration for surface leases and pipelines, reduced by the estimated salvage values for all included wells and facilities, is estimated to be nominal.

Tax Horizon

The Corporation does not expect to pay current income tax for the 2014 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not be taxable in 2015. The Corporation does not expect to pay current taxes until 2016 or beyond.

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, 2014:

	$000's
Property acquisition costs	
Proved properties	176,428
Undeveloped properties	16,701
Exploration costs	1,601
Development costs	486,165
Dispositions	(9,809)
Corporate Assets	11,163
Total	682,249

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, 2014.

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	-	-	63	36.39
Natural Gas	3	0.88	44	21.86
Heavy Oil	-	-	-	-
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	-	-
Total	3	0.88	107	58.25

For additional details on the exploration and development activities during 2014, 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, 2015, 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 Oil (Bbls/d)**	**Heavy Oil (Bbls/d)**	**Natural Gas(1) (Mcf/d)**	**Natural Gas Liquids (Bbls/d)**	**Total (BOE/d)**
Total Proved	4,261	44	168,540	9,158	41,553
Total Proved Plus Probable	4,793	46	209,005	11,521	51,193

Note:

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

The Ferrier property in the West Central area accounts for 28,489 BOE/d, or 56% of the estimated total production on a proved plus probable basis. This is reflected in the estimate of gross proved plus probable reserves.

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			
	2014			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production[1]				
Light and Medium Crude Oil (Bbls/d) [2]	6,139	5,566	6,686	6,973
Natural Gas (Mcf/d)[3]	178,443	157,244	142,214	135,865
NGLs (Bbls/d) [4]	7,065	6,065	5,954	5,432
Combined (BOE/d)	42,945	37,838	36,342	35,049
Average Price Received				
Light and Medium Crude Oil ($/Bbl) [2]	71.92	90.39	103.25	98.27
Natural Gas ($/Mcf)[3]	4.01	4.44	5.04	5.88
NGLs ($/Bbl) [4]	31.26	43.20	42.70	57.50
Combined ($/BOE)	32.07	38.67	45.72	51.27
Royalties Paid				
Light and Medium Crude Oil ($/Bbl) [2]	15.73	21.67	17.39	19.73
Natural Gas ($/Mcf)[3]	0.38	0.55	0.84	0.70
NGLs ($/Bbl) [4]	9.03	9.49	10.37	13.10
Combined ($/BOE)	5.33	7.00	8.17	8.68
Operating Expenses				
Light and Medium Crude Oil ($/Bbl) [2]	9.03	8.09	7.19	8.23
Natural Gas ($/Mcf)[3]	1.61	1.49	1.32	1.35
NGLs ($/Bbl) [4]	9.78	9.20	7.94	8.09
Combined ($/BOE)	9.57	8.85	7.80	8.12
Netback Received before Transportation				
Light and Medium Crude Oil ($/Bbl) [2]	47.16	60.63	78.67	70.31
Natural Gas ($/Mcf)[3]	2.02	2.40	2.88	3.83
NGLs ($/Bbl) [4]	12.45	24.51	24.39	36.31
Combined ($/BOE)	17.17	22.82	29.75	34.47
Transportation Costs				
Light and Medium Crude Oil ($/Bbl) [2]	1.70	2.69	0.99	3.37
Natural Gas ($/Mcf)[3]	0.19	0.21	0.16	0.24
NGLs ($/Bbl) [4]	-	-	-	-
Combined ($/BOE)	1.05	1.25	0.82	1.61
Netback Received after Transportation [5]				
Light and Medium ($/Bbl) [2]	45.46	57.94	77.68	66.94
Natural Gas ($/Mcf)[3]	1.83	2.19	2.72	3.59
NGLs ($/Bbl) [4]	12.45	24.51	24.39	36.31
Combined ($/BOE)	16.12	21.57	28.93	32.86

Notes:

(1) Includes minor royalty volumes received but does not deduct royalty volumes paid.
(2) Includes minor amounts of heavy oil production.
(3) Includes minor amounts of coal bed methane and shale gas production.
(4) NGL pricing excludes condensate.
(5) Netbacks are calculated by subtracting royalties, operating and transportation costs from revenues.

The following table indicates average daily company share production from important fields in respect of our assets for the year ended December 31, 2014. 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)	Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d) [2]
West Central Alberta Region					
Ferrier	394	1,171	109,000	2,924	22,655
Harmattan	1,165	21	11,609	1,829	4,950
Strachan	614	227	2,340	484	1,715
Greater Pembina	1,273	42	2,968	119	1,928
Willesden Green	406	46	7,027	275	1,898
Total West Central Alberta Region	3,852	1,507	132,944	5,631	33,147
Other Properties	860	117	20,631	502	4,918
TOTALS	4,712	1,624	153,575	6,133	38,065

Note:

(1) Includes minor amounts of heavy oil production.
(2) May not add due to rounding.

For the twelve months ended December 31, 2014, approximately 53.5% of gross revenue from our assets was derived from crude oil and natural gas liquids production and 46.5% 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.

DESCRIPTION OF SHARE CAPITAL

Bellatrix is authorized to issue an unlimited number of Common Shares. Holders of Common Shares are entitled to one vote per share at meetings of shareholders of Bellatrix, to receive dividends if, as and when declared by the Board and to receive pro rata the remaining property and assets of Bellatrix upon its dissolution or winding-up, subject to the rights of shares having priority over the Common Shares.

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 table sets forth the price range and trading volume of the Common Shares on the TSX for the periods indicated.

TSX

Period	High ($)	Low ($)	Volume
2014			
January	8.66	7.64	34,284,312
February	8.45	7.76	13,860,667
March	9.44	8.29	24,286,566
April	10.92	9.11	32,818,692
May	11.65	9.40	59,888,744
June	9.79	8.88	38,331,814
July	9.68	7.95	31,476,677
August	8.87	7.35	26,641,463
September	8.40	6.81	29,607,901
October	7.03	4.94	46,100,884
November	5.82	4.36	33,336,332
December	4.86	3.45	32,600,976

2015			
January	4.46	2.38	27,602,536
February	3.93	2.52	45,838,176
March (1 – 13)	3.95	3.29	12,347,936

NYSE

Period	High (US$)[(1)]	Low (US$)[(1)]	Volume[(1)]
2014			
January	7.88	6.93	3,016,889
February	7.65	6.98	2,508,514
March	8.55	7.47	3,835,236
April	10.00	8.26	5,743,095
May	10.70	8.65	8,882,590
June	8.95	8.15	8,386,451
July	9.14	7.30	7,931,166
August	8.10	6.73	12,055,758
September	7.69	6.11	8,597,920
October	6.28	4.38	13,214,190
November	5.17	3.82	10,826,490
December	4.28	2.97	11,003,440
2015			
January	3.81	1.86	10,065,469
February	3.16	2.00	22,305,676
March (1 – 13)	3.17	2.57	11,157,086

Note:

(1) Reflects trading on the NYSE MKT from January 1, 2014 to October 5, 2014 and trading on the NYSE from October 6, 2014 to March 13, 2015.

PRIOR SALES

Other than the Common Shares and options to purchase Common Shares under the share option plan of the Corporation, Bellatrix did not sell or issue any securities of the Corporation during the year ended December 31, 2014. The following table sets out details of all options granted under the share option plan of the Corporation during the year ended December 31, 2014:

Date	Type of Security	Number of Securities	Price per Security ($)[(1)]
January 1, 2014	Options	45,000	7.74
January 10, 2014	Options	20,000	8.05
March 24, 2014	Options	163,000	8.84
April 22, 2014	Options	56,000	10.04
June 13, 2014	Options	2,597,000	9.24
June 16, 2014	Options	55,000	9.25
June 23, 2014	Options	10,000	9.37
July 14, 2014	Options	119,000	9.38
July 16, 2014	Options	11,000	9.07
July 17, 2014	Options	3,500	8.87
August 15, 2014	Options	119,000	7.61
August 18, 2014	Options	7,000	7.56
December 11, 2014	Options	871,500	4.06

Note:

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

ESCROWED SECURITIES

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

BORROWINGS

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 May 30, 2017, do not require any mandatory principal payments prior to maturity, and can be further extended beyond May 2017 with the consent of the lenders. If not extended, the Credit Facilities will be due in full 366 days thereafter. The Credit Facilities are available to finance Bellatrix's ongoing capital expenditures, working capital requirements and for general corporate purposes. As at December 31, 2014, and as at the date hereof, the Credit Facilities consist of a $75 million operating facility provided by a Canadian chartered bank and a $650 million syndicated facility provided by nine financial institutions. The available Credit Facilities and related borrowing base are subject to semi-annual reviews in May and November of each year. In the Corporation's semi-annual borrowing base review for November 30, 2014, the Corporation and its lenders agreed to increase the borrowing base and Credit Facilities to $725 million from $625 million.

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 of $725 million. The borrowing base will be subject to re-determination on 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, 2015.

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, and 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 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 number of financial covenants, all of which were met as at December 31, 2014. The Corporation calculates its financial covenants quarterly. The calculation for each financial covenant is based on specific definitions that are not in accordance with IFRS and cannot be readily replicated by referring to the Corporation's consolidated financial statements. As at December 31, 2014, the agreement governing the Credit Facilities had financial covenants of a maximum total debt to EBITDA ratio of 3.5 to 1 (4.0 to 1 for the two fiscal quarters immediately following a material acquisition), a maximum senior debt to EBITDA ratio of 3.0 to 1 (3.5 to 1 for the two fiscal quarters immediately following a material acquisition), and a minimum EBITDA to interest expense (last four fiscal quarters) ratio of 3.5 to 1. Effective March 11, 2015, the lending syndicate under the Credit Facilities agreed to revise both the maximum total debt to EBITDA and maximum senior debt to EBITDA financial covenants to the following: (i) 4.75 to 1 for the fiscal quarters ending September 30, 2015, December 31, 2015, March 31, 2016 and June 30, 2016; and (ii) 4.0 to 1 for the fiscal quarters ending September 30, 2016, December 31, 2016, and March 31, 2017. During the periods in which these revised financial covenants are in place, the additional automatic relaxation of the debt to EBITDA financial covenants following a material acquisition will not apply. Commencing with the second quarter of 2017, the maximum senior debt to EBITDA ratio will return to 3.0 to 1 (3.5 to 1 for the two fiscal quarters immediately following a material acquisition) and the maximum total debt to EBITDA ratio will return to 3.5 to 1 (4.0 to 1 for the two fiscal quarters immediately following a material acquisition). The minimum EBITDA to interest expense ratio of 3.5 to 1 remains unchanged as at March 11, 2015.

DIRECTORS AND OFFICERS

The following table sets forth the name, age (as at December 31, 2014), province or state and country of residence, date first elected as a director of Bellatrix where applicable and office held for each of the 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
Raymond G. Smith, P. Eng. Calgary, Alberta, Canada Age: 67	President, Chief Executive Officer and Director	April 25, 2005	President and Chief Executive Officer of Bellatrix, and prior to November 1, 2009 of True Energy Inc. (as administrator of True Energy Trust), since January 26, 2009. Director of Madalena Ventures Inc. since October 2005. From June 2007 to November 2007 President, CEO and Chairman of Cork Exploration Inc. and Chairman of Cork Exploration Inc. from April 2005 to November 2007; from September 2002 to January 2004, Chairman, President and Chief Executive Officer of Meridian Energy Corporation; and Chairman and Chief Executive Officer of Meridian Energy Corporation from January 2004 to March 2005. Prior thereto, Mr. Smith was President and Chief Executive Officer of Corsair Exploration Ltd.
Brent A. Eshleman, P. Eng. Calgary, Alberta, Canada Age: 50	Executive Vice-President and Chief Operating Officer	N/A	Chief Operating Officer of Bellatrix since September 1, 2014 and Executive Vice-President of Bellatrix since July 2012. Prior thereto, 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, CA Calgary, Alberta, Canada Age: 59	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.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
Mark L. Stephen, P. Eng. Calgary, Alberta, Canada Age: 54	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.
Russell G. Oicle P. Geol. Calgary, Alberta, Canada Age: 59	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.
Timothy A. Blair Cochrane, Alberta, Canada Age: 56	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.
Garrett K. Ulmer, P. Eng. Calgary, Alberta, Canada Age: 44	Vice-President, Engineering	N/A	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.
Chris D. Curry, CA Calgary, Alberta, Canada Age: 40	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.
Kelly M. Nichol Calgary, Alberta, Canada Age: 49	Vice-President, Business Development	N/A	Vice-President, Business Development of the Corporation since May 2013 and prior thereto, a business development consultant to the Corporation since 2012. Formerly Vice-President, Business Development with Daylight Energy Ltd. from 2008 to 2012.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
Leanne K. Gress-Blue, CA Calgary, Alberta, Canada Age: 46	Vice-President, Finance	N/A	Vice-President, Finance of Bellatrix since April 1, 2013 and prior thereto, Treasurer of Bellatrix. Prior to November 1, 2009, Treasurer of True Energy Inc. (as administrator of True Energy Trust).
Steve G. Toth, CFA Calgary, Alberta, Canada Age: 37	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.
Charles R. Kraus, Esq. Calgary, Alberta, Canada Age: 39	Vice-President, General Counsel and Corporate Secretary	N/A	Vice-President, General Counsel and Corporate Secretary of Bellatrix 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.
David R. Laing Calgary, Alberta, Canada Age: 56	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.
W.C. (Mickey) Dunn Calgary, Alberta, Canada Age: 61	Chairman[(4)(5)]	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.
Doug N. Baker, FCA Calgary, Alberta, Canada Age: 61	Director[(2)(5)]	April 26, 2007	Independent businessman. Mr. Baker currently serves as a director and Chair of the Audit Committee for RMP Energy Inc. and Century Energy Ltd. Served as Chair of the Canadian Institute of Chartered Accountants from 2008 to 2010. Previously a director of Genesis Land Development Corp. from May 2010 to September 2012, Longview Oil Corp. from March 2011 to June 2014, Winstar Resources Ltd. from May 2006 to April 2013 and ATB Financial Ltd from May 2009 to May 2014.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[(1)]	Principal Occupation
Murray L. Cobbe Calgary, Alberta, Canada Age: 65	Director[(3)(4)]	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 Pason Systems Inc. since 2001. Director of Secure Energy Services Inc. since 2009.
John H. Cuthbertson, Q.C. Calgary, Alberta, Canada Age: 64	Director[(5)]	August 31, 2000	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Melvin M. Hawkrigg, BA, FCA, LL.D. (Hon.) Waterdown, Ontario, Canada Age: 84	Director[(2)]	March 31, 2009	Chairman, Orlick Industries Limited, a private automotive supply company from 1998.
Robert A. Johnson, P.Geol. Calgary, Alberta, Canada Age: 78	Director[(3)]	September 21, 2009	Independent businessman. Executive Vice-President of Grey Wolf Exploration Inc. from 2000 to July 2009.
Daniel Lewis New York City, New York, USA Age: 39	Director	January 1, 2015[(7)]	Co-founder and Managing Partner of Orange Capital, a New York based investment fund, since 2005. From 1996 to 2004, Mr. Lewis was employed by Citigroup and its predecessor companies.
Keith E. Macdonald, CA Calgary, Alberta, Canada Age: 58	Director[(2)(4)]	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.
Steven J. Pully, Esq., CPA, CFA Dallas, Texas, USA Age: 54	Director[(4)(5)]	January 1, 2015[(7)]	Independent businessman and consultant; 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: 79	Director[(3)]	November 2, 2005	President and CEO of Canada Hibernia Holding Corporation (an oil and gas production company).
Keith Turnbull, B.Sc. CA Calgary, Alberta, Canada Age: 65	Director[(2)]	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).
(2) Member of Audit Committee.
(3) Member of Reserves, Safety and Environment Committee.
(4) Member of Compensation Committee.
(5) Member of Corporate Governance Committee.
(6) 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.
(7) On December 15, 2014, the Corporation announced the appointment of Daniel Lewis and Steven J. Pully to the Board, effective January 1, 2015.

As at February 28, 2015, the directors and officers of Bellatrix, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 30,860,220 Common Shares, representing approximately 16.08% of the issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders

To the knowledge of Bellatrix, 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.

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 The Cash Store Financial Services Inc. from May 1, 2003 until his resignation on January 2, 2014. On April 14, 2014, The Cash Store Financial Services Inc., 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. The proceedings remain ongoing as at December 31, 2014.

Charles R. Kraus, the Vice-President, General Counsel & 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
Doug N. Baker, FCA Calgary, Alberta, Canada	Yes	Yes	Mr. Baker, who served as the Chair of the Canadian Institute of Chartered Accountants from 2008 to 2010, and served as the President of the Institute of Chartered Accountants of Alberta in 2003, brings considerable experience in finance, tax and accounting to the Audit Committee. An independent businessman, Mr. Baker currently serves as a director and

Name and municipality of residence	Independent	Financially literate	Relevant education and experience
			Chair of the Audit Committee for RMP Energy Inc. and Century Energy Ltd. Prior thereto, Mr. Baker was Chief Financial Officer of Valiant Energy Inc. and predecessor companies, Forte Resources Inc. and Forte Energy Ltd. from 1997 to 2006. Prior to 1997, Mr. Baker held senior financial positions in several public companies. Mr. Baker is a graduate of the University of Saskatchewan and holds a Bachelor of Commerce degree with Honours and Distinction. He has been a chartered accountant since 1977. In 1996, Mr. Baker received the honour of being named a Fellow of Chartered Accountants.
Melvin M. Hawkrigg, BA, FCA, LL.D (Hon.) Waterdown, Ontario, Canada	Yes	Yes	Mr. Hawkrigg is the Chairman of Orlick Industries Limited, a private automotive supply company and has held such position since 1998. Mr. Hawkrigg has served as a board and audit committee member for a number of Canadian public corporations. Mr. Hawkrigg holds a Bachelor of Arts from McMaster University, received the honour of being a Fellow of the Institute of Chartered Accountants in 1985 and received an Honorary Doctor of Laws degree from McMaster University in 1997.
Keith E. Macdonald, CA Calgary, Alberta, Canada	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 is currently the Chief Executive Officer and a director of EFLO Energy Inc. and has held such positions since March 2011. He is a also a director of Surge Energy Inc., Madalena Ventures Inc. and Mountainview Energy Ltd. Mr. MacDonald is a Chartered Accountant.
Keith Turnbull, B.Sc. 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 audit committee member of Crown Point Energy Inc. and Renegade Petroleum Ltd.

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 MKT/NYSE listing and due diligence work in respect of financings and a corporate acquisition were $900,900 in 2014 and $657,200 in 2013.

Audit – Related Fees

There were $92,820 in 2014 and $111,180 in 2013 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

No fees were billed for professional services rendered by the external auditor for tax compliance, tax advice and tax planning in 2014 or 2013.

All Other Fees

No other professional services fees were billed by the external auditor for other non-audit related fees in 2014 or 2013.

INDUSTRY CONDITIONS

Companies operating in the oil and natural gas industry are subject to extensive regulation and control of operations (including land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government with respect to the pricing and taxation of oil and natural gas through agreements among the governments of Canada, Alberta, British Columbia, and Saskatchewan all of which should be carefully considered by investors in the oil and gas industry. All current legislation is a matter of public record and the Corporation is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry in western Canada.

Pricing and Marketing

Oil

In Canada, the 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 is currently undergoing a consultation process to update the regulations governing the issuance of export licences. The updating process is necessary to meet the criteria set out in the federal *Jobs, Growth and Long-term Prosperity Act* (Canada) (the "**Prosperity Act**") which received Royal Assent on June 29, 2012. In this transitory period, the NEB has issued, and is currently following an "Interim Memorandum of Guidance concerning Oil and Gas Export Applications and Gas Import Applications" under Part VI of the *National Energy Board Act* (Canada).

Natural Gas

Alberta's natural gas market has been deregulated since 1985. Supply and demand determine the price of natural gas and price is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, on a gas transmission system such as the Alberta "NIT" (Nova Inventory Transfer), at a storage facility, at the inlet to a utility system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon such producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange (NGX), Intercontinental Exchange or the New York Mercantile Exchange (NYMEX) in the United States, spot and future prices can also be influenced by supply and demand fundamentals on these platforms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such license requires the approval of the Governor in Council acting on the advice of the Federal Cabinet of the Government of Canada and the NEB. The Government of Alberta also regulates the volumes of natural gas that may be removed from that province for consumption elsewhere based on factors such as reserve availability, transportation and market considerations.

Gaining access to the market is currently a concern for the industry as a whole. Any producer's ability to market its product largely depends upon its ability to acquire space on pipelines that deliver oil and natural gas to commercial markets or to arrange for alternate transportation such as rail. While several pipeline expansions and proposed projects have been commenced, announced or are waiting for regulatory approval, the lack of firm pipeline capacity and regulatory delays for the approval of certain projects continue to affect the oil and natural gas industry and limit producers' ability to market their oil and natural gas production. While the use of rail transportation has significantly increased over the last few years, similar to the concern over the lack of pipeline capacity, issues with respect to capacity and uncertainty with respect to anticipated (but currently unknown) regulatory changes may also impact a producer's ability to access the market through this alternative method.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply.

All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes.

Royalties and Incentives

General

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

Alberta

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

Royalties are currently paid pursuant to "The New Royalty Framework" (implemented by the *Mines and Minerals (New Royalty Framework) Amendment Act, 2008*) and the "Alberta Royalty Framework", which was implemented in 2010. Royalty rates for conventional oil are set by a single sliding rate formula, which is applied monthly and incorporates separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime as set at 40%. Royalty rates for natural gas under the royalty regime are similarly determined using a single sliding rate formula incorporating separate variables to account for production rates and market prices. Effective January 1, 2011, the maximum royalty payable under the royalty regime set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the prices component of the natural gas royalty formula to moderate the increase in the royalty rate at prices higher than $5.25/GJ compared to the previous royalty curve.

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

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

The Government of Alberta currently has in place two royalty programs, both of which commenced in 2008 with the intention to encourage the development of deeper, higher cost oil and natural gas reserves. A five-year program for conventional oil exploration wells over 2,000 metres provides qualifying wells with up to a $1 million or 12 months of royalty relief, whichever comes first, and a five-year program for natural gas wells deeper than 2,500 metres provides a sliding scale royalty credit based on depth of up to $3,750 per metre. On May 27, 2010, the natural gas deep drilling program was amended, retroactive to May 1, 2010, by reducing the minimum qualifying depth to 2,000 metres, removing a supplemental benefit of $875,000 for wells exceeding 4,000 metres that are spudded subsequent to that date, and including wells drilled into pools drilled prior to 1985, among other changes.

On March 27, 2011, the Government of Alberta approved the *New Well Royalty Regulation* providing for the permanent implementation of a formerly temporary royalty program which provides for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" is reached, whichever comes first.

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months 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 level of the freehold production tax is based on the volume of monthly production. It is either a flat rate, or, beyond a certain production level, is determined using a sliding scale formula based on the production level. For natural gas, the freehold production tax is either a flat rate, or, at certain production levels, is determined using a sliding scale formula based on the reference price similar to that applied to natural gas production on Crown land, and depends on whether the natural gas is conservation gas or non-conservation gas. The production tax rate for freehold natural gas liquids is a flat rate of 12.25%.

As of January 1, 2017 all liquid natural gas ("**LNG**") facilities will be subject to a 3.5% income tax. This income tax is scheduled to increase to 5% in 2037. During the period in which net operating losses and capital investment are deducted, a tax rate of 1.5% will apply to the taxpayer's net income. Once the net operating losses and capital investment have been depleted, the full rate of 3.5% is payable. To encourage investment the British Columbia government will offer a corporate income tax credit to any LNG taxpayer based on the amount of LNG acquired for an LNG facility.

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

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

- *Deep Re-Entry Royalty Credit Program* providing a royalty credit for deep re-entry wells with a true vertical depth to the top of pay 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 m^3 of royalty free gas for deep discovery wells with a true vertical depth greater than 4,000 metres whose surface locations are at least 20 kilometres away from the surface location of any well drilled into a recognized pool within the same formation;

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

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

- *Ultra-Marginal Royalty Reduction Program* providing royalty reductions for low productivity, shallow natural gas wells. Vertical wells must be less than 2,500 metres and horizontal wells less than 2,300 metres to be eligible. Production in the first 12 months ending after January 2007 must be less than 17m^3 per metre of depth for exploratory wildcat wells and less than 11m^3 per metre of depth for development wells and exploratory outpost wells. The well must have been spudded or re-entered after December 31, 2005. A reduction is realized in each month that average daily production is less than 60,000m^3. Horizontal wells that are 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 also be exempt from the payment of a royalty for the first 36 months of production or 11,450 m^3 of production, whichever comes first.

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

The Petroleum and Natural Gas Royalty and Freehold Production Tax Regulation has been amended effective April 1, 2013 to provide for a 6% minimum royalty on tier 1 wells and a 3% minimum royalty on tier 2wells which claim the deep well/deep re-entry credits. The minimum royalty applies to tier 1 and tier 2 wells when the net royalty payable would otherwise be zero for a production month.

Saskatchewan

In Saskatchewan, taxes ("**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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Effective April 1, 2014, the Saskatchewan Ministry of the Economy streamlined fees related to licenses 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. While the fees have been streamlined, approvals to conduct the relevant activities are still required. These changes to the fee structure are part of ongoing work by the Government of Saskatchewan to streamline the licensing, regulation and monitoring processes in the oil and gas sector.

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, British Columbia expanded its policy of deep rights reversion for new leases to provide for the reversion of both shallow and deep formations that cannot be shown to be capable of production at the end of their primary term.

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

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

Federal

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

Alberta

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

Environmental compliance in Alberta for the oil and gas industry is primarily governed by the *Environmental Protection and Enhancement Act* (Alberta) (the "**EPEA**") and the *Oil and Gas Conservation Act* (Alberta) (the "**OGCA**"). The EPEA and the OGCA both impose environmental responsibilities on oil and natural gas operators and working interest holders in Alberta, and also provide for, among other things, the imposition of significant fines and penalties for violations. The EPEA and the OGCA create standards with respect to the release of effluents and emissions, including sulphur dioxide and nitrogen oxide, and set out reporting and monitoring obligations. Dewatering requirements, particularly to the extent that saline water or water containing traces of hydrocarbons is required to be released, stored or disposed of, is impacted by such environmental laws. Significant sanctions may be imposed for non-compliance with environmental laws.

In addition to general environmental and oil and natural gas laws protecting fresh water resources, in Alberta diversions of water and activities related to water, which is regulated as a provincial resources, require appropriate approvals or licenses pursuant to the *Water Act* (Alberta). Oil and natural gas production activities produce salt water and require disposal permits to allow producers to dispose of produced water in deeper saltier water bearing horizons, or saline aquifers. Producers, including Bellatrix, regularly required water approvals, licenses and disposal permits as may be required, and they are routinely approved by the AER.

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

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

On August 22, 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("**LARP**") which came into force on September 1, 2012. The LARP is the first of seven regional plans developed under the ALUF. LARP covers a region in the northeastern corner of Alberta that is approximately 93,212 square kilometres in size. The region includes a substantial portion of the Athabasca oil sands area, which contains approximately 82% of the province's oil sands resources and much of the Cold Lake oil sands area.

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

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. Similar to LARP, 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.

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

British Columbia

In British Columbia, the *Oil and Gas Activities Act* (the "**OGAA**") impacts conventional oil and gas producers, shale gas producers and other operators of oil and gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission (the "**Commission**") has broad powers, particularly with respect to compliance and enforcement and the setting of technical safety and operational standards for oil and gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives for water, riparian habitats, wildlife and wildlife habitat, old-growth forests and cultural heritage resources. The OGAA requires the Commission to consider these environmental objectives in deciding whether or not to authorize an oil and gas activity. In addition, although not an exclusively environmental statute, the *Petroleum and Natural Gas Act*, 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, Saskatchewan passed changes to *The Oil and Gas Conservation Act* ("**SKOGCA**"), the act governing the regulation of resource development operations in the province. Although the associated Bill received Royal Assent on May 18, 2011, it was not proclaimed into force until April 1, 2012, in conjunction with the release of *The Oil and Gas Conservation Regulations, 2012* ("**OGCR**") and *The Petroleum Registry and Electronic Documents Regulations* ("**Registry Regulations**"). The aim of the amendments to the SKOGCA, and the associated regulations, is to provide resource companies investing in Saskatchewan's energy and resource industries with the best support services and business and regulatory systems available. With the enactment of the Registry Regulations and the OGCR, Saskatchewan has implemented a number of operational aspects, including the increased demand for record-keeping, increased testing requirements for injection wells and increased investigation and enforcement powers; and, procedural aspects including those related to Saskatchewan's participation as partner in the Petroleum Registry of Alberta.

Liability Management Rating Programs

Alberta

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

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

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

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

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

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

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

On July 4, 2014, the AER introduced 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 will be 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*.

British Columbia

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

Saskatchewan

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

Climate Change Regulation

Federal

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.

The Government of Canada is a signatory to the *United Nations Framework Convention on Climate Change* (the "**UNFCCC**") and a participant to the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("**GHG**") emissions). On January 29, 2010, Canada inscribed in the Copenhagen Accord its 2020 economy-wide target of a 17% reduction of

GHG emissions from 2005 levels. This target is aligned with the United States target. In a report dated October 2013, the Government stated that this target represents a significant challenge in light of strong economic growth (Canada's economy is projected to be approximately 31% larger in 2020 compared to 2005 levels).

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

Alberta

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

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

The SGER, effective July 1, 2007, applies to facilities emitting more than 100,000 tonnes of GHGs in 2003 or any subsequent year, and requires reductions in GHG emissions intensity (e.g. the quantity of GHG emissions per unit of production) from emissions intensity baselines established in accordance with the SGER. The SGER distinguishes between "Established Facilities" and "New Facilities". Established Facilities are defined as facilities that completed their first year of commercial operation prior to January 1, 2000 or that have completed eight or more years of commercial operation. Established Facilities are required to reduce their emissions intensity by 12% of their baseline emissions intensity for 2008 and subsequent years. Generally, the baseline for an Established Facility reflects the average of emissions intensity in 2003, 2004 and 2005. New Facilities are defined as facilities that completed their first year of commercial operation on December 31, 2000, or a subsequent year, and have completed less than eight years of commercial operation, or are designated as New Facilities in accordance with the SGER. New Facilities are required to reduce their emissions intensity by 2% from 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 and 10% of their baseline in the eighth year. Neither the CCEMA nor the SGER contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA provides that regulated emitters can meet their emissions intensity targets by (i) making improvements to their operations, (ii) contributing to the Climate Change and Emissions Management Fund at a rate of $15 per tonne of CO_2 equivalent, (iii) purchasing emissions credits from other regulated emitters that have reduced their emissions intensities below their respective emission intensity requirements, (iv) purchasing emission offset credits from non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. The funds contributed by industry to the Climate Change and Emissions Management Fund will be used to drive innovation and test and implement new technologies for greening energy production. Emissions credits can also be purchased from regulated emitters that have reduced their emissions below the 100,000 tonne threshold or non-regulated emitters that have generated emissions offsets through activities that result in emissions reductions in accordance with established protocols published by the Government of Alberta. The provisions of the SGER are currently undergoing a Review by the Government of Alberta and will remain in force through June, 2015.

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

British Columbia

In February 2008, British Columbia announced a revenue-neutral carbon tax that took effect July 1, 2008. The tax is consumption-based and applied at the time of retail sale or consumption of virtually all fossil fuels purchased or used in British Columbia. The current tax level is $30 per tonne of CO_2 equivalent. The final scheduled increase took effect on July 1, 2012. There is no plan for further rate increases or expansions at this time. In order to make the tax revenue-neutral, British Columbia has implemented tax credits and reductions in order to offset the tax revenues that the Government of British Columbia would otherwise receive from the tax.

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

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

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 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 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.

As is standard industry practice, the Corporation is not fully insured against all risks, nor are all risks insurable. Although the Corporation maintains liability insurance in an amount that it considers consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event the Corporation could incur significant costs.

Global Financial Markets

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the American and European sovereign debt levels, have caused significant volatility in commodity prices. These events and conditions have caused a decrease in confidence in the broader United States and global credit and financial markets and have created a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and are likely to continue to impact the performance of the global economy going forward. Worldwide crude oil commodity prices are expected to remain volatile in the near future as a result of global excess supply, recent actions taken by the Organization of the Petroleum Exporting Countries ("**OPEC**"), and ongoing global credit and liquidity concerns. This volatility may affect the Corporation's ability to obtain equity or debt financing on acceptable 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 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 conditions, in the United States, Canada and Europe, 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, 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 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.

Market Price of Common Shares

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to the Corporation's performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices or current perceptions of the oil and gas market. Similarly, the market price of the Common Shares could be subject to significant fluctuations in response to variations in the Corporation's operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which the Common Shares will trade cannot be accurately predicted.

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.

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.

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, Pipeline Systems and Rail

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. Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and 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. 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 and it is projected to continue in this upward trend. 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.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. These recommendations include, among others, the imposition of higher standards for all DOT-111 tank cars carrying crude oil and the increased auditing of shippers to ensure they properly classify hazardous materials and have adequate safety plans in place. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and add additional costs to the transportation of crude oil by rail.

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. 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. 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, 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. 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.

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.

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 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 becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes of the ratio of the Corporation' deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted. See: "*Industry Conditions*".

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 greenhouse gas ("**GHG**") emissions legislation at the provincial or federal level. See: "*Industry Conditions*". Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") and a participant to the Copenhagen Agreement (a non-binding agreement created by the UNFCCC), the Government of Canada announced on January 29, 2010 that it will seek a 17% reduction in GHG emissions from 2005 levels by 2020. These GHG emission reduction targets are not binding, however. Some of the Corporation's significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. The direct or indirect costs of compliance with these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Corporation and its operations and financial condition.

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 will 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.

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 if applicable, the cash available for dividends 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. 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 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. There is risk that if the economy and banking industry experienced unexpected and/or prolonged deterioration, the Corporation's access to additional financing may be affected.

Because of global economic 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. 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 include certain financial ratio tests, which from time to time either affect the availability, or price, of additional funding. As a result of the precipitous drop in crude oil prices, the Corporation and the Credit Facility lenders recently amended certain of the financial covenants under the Credit Facilities. In the event that the Corporation is not able to comply with the covenants, as amended, the banking syndicate may not be willing to agree to a further amendment to the financial covenants 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 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. A further material decline in commodity prices could reduce the Corporation's borrowing base, reducing the funds available to the Corporation under the credit facility. This could result in the requirement to repay a portion, or all, of the Corporation's bank 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.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Corporation and may delay exploration and development activities.

Diluent Supply

Heavy oil and bitumen are characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the transportation of heavy oil and bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport heavy oil and bitumen to market and correspondingly increasing the Corporation's overall operating cost, decreasing its net revenues and negatively impacting the overall profitability of its heavy oil and bitumen projects.

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.

Ability of Residents of the United States to Enforce Civil Remedies

Bellatrix is organized under the laws of Alberta, Canada and our principal places of business are in Canada. Most of our directors and all of our officers and the experts named herein are residents of Canada, and a substantial portion of our assets and all or a substantial portion of the assets of such persons are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon those directors, officers and experts who are not residents of the United States or to enforce against them judgments of United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or against any of our directors, officers or experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or the securities laws of any state within the United States.

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.

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.

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.

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.

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. 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 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.

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.

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, 2014 Bellatrix employed 201 full-time employees (135 are located in the head office and 66 are field employees) and 133 full-time consultants (28 are located in the head office and 105 are in the field). As at December 31, 2014, Bellatrix did not employ any part-time employees or consultants.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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.

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 Sproule, the Corporation's independent engineering evaluators and KPMG LLP, the Corporation's auditors. None of Sproule or the "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 Sproule have or are 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 Sproule 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 2014 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, 2014, 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), Bellatrix has not entered into any material contracts within the last financial year, or before the last financial year which are still in effect.

AUDITORS, TRANSFER AGENT AND REGISTRAR

The auditors of Bellatrix are KPMG LLP, Chartered 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 and on EDGAR at www.sec.gov.

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 "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014 estimated using forecast prices and costs.

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

The Reserves Committee of the board of directors of the Corporation has

(a) reviewed the Corporation'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 Corporation'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 19th day of March, 2015.

(signed) "*Raymond G. Smith*"
Raymond G. Smith, P.Eng.
President and Chief Executive Officer

(signed) "*Edward J. Brown*"
Edward J. Brown, C.A.
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, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014 estimated using forecast prices and costs.

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

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

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

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2014, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management and Board of Directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (County)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate) Audited (M$)	Evaluated (M$)	Reviewed (M$)	Total (M$)
Sproule	Evaluation of the P&NG Reserves of Bellatrix Exploration Ltd., As of December 31, 2014, prepared November 2014 to February 2015	Canada	Nil	2,115,605	Nil	2,115,605

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

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

7. 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:

Sproule Associates Limited
Calgary, Alberta
February 27, 2015

Per: (signed) "*Geoffrey W. Beatson, P. Eng.*"
Manager, Engineering and Partner

Per: (signed) "*Douglas O. McNichol, P.Eng.*
Senior Petroleum Engineer and Partner

Per: (signed) "*Rodney E. Fradette, P. Eng.*"
Senior Petroleum Engineer and Partner

Per: (signed) "*James D. Hudson, P.L. (Eng.)*"
Senior Petroleum Technologist and Partner

Per: (signed) "*Linda Echikh, P.Geol.”*
Senior Petroleum Geologist

Per: (signed) "*Tony K. Wong, P.Geol.*"
Senior Petroleum Geologist and Partner

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

Per: (signed) "*Nora T. Stewart, P.Eng.*"
Senior Vice-President, Canada and 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 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. Report regularly to the Board;

27. 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.

October 6, 2014

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.