bellatrix EXPLORATION LTD

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED

DECEMBER 31, 2011

March 14, 2012

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ABBREVIATIONS

Oil and Natural Gas Liquids

Bbl	barrel
Bbls	barrels
Mbbls	thousand barrels
MMbbls	million barrels
Mstb	1,000 stock tank barrels
Bbls/d	barrels per day
BOPD	barrels of oil per day
NGLs	natural gas liquids
STB	stock tank barrels

Natural Gas

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

Other

AECO	the natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale.
BOE	barrel of oil equivalent of natural gas and crude oil on the basis of 1 BOE for 6 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

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.

Where any disclosure of reserves data is made in this annual information form that does not reflect all reserves of Bellatrix, the reader should note that the estimates of reserves and future net revenue for individual properties or groups of 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.

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:

"**2004 Arrangement**" means the plan of arrangement involving, among others, TKE Energy Inc., TUSK Energy Corporation and the Trust completed on November 2, 2004 under the ABCA pursuant to which, among other things, the Trust acquired all of the issued and outstanding common shares of TKE Energy Inc.;

"**2005 Arrangement**" means the plan of arrangement involving, among others, the Trust, True Energy Inc., TKE Energy Inc and Vero Energy Inc. completed on November 2, 2005 under the ABCA pursuant to which, among other things, the Trust acquired all of the issued and outstanding common shares of True Energy Inc.;

"**2009 Arrangement**" means the plan of arrangement involving, among others, the Trust, True Energy and securityholders of the Trust completed on November 1, 2009 under the ABCA which resulted in the reorganization of the Trust into a public exploration and production company, being Bellatrix, that owns all of the existing assets and assumed all of the existing liabilities of the Trust;

"**4.75% Debenture Indenture**" means the trust indenture dated April 20, 2010 between the Corporation and Computershare Trust Company of Canada governing the terms of the 4.75% Debentures;

"**4.75% Debentures**" means the 4.75% convertible unsecured subordinated debentures of the Corporation issued pursuant to the 4.75% Debenture Indenture;

"**7.50% Debenture Indenture**" means the trust indenture dated June 15, 2006, as amended by the supplemental indenture dated as of November 1, 2009 and as amended and restated as of November 1, 2009 among the Corporation and Computershare Trust Company of Canada governing the terms of the 7.50% Debentures;

"**7.50% Debentures**" means the 7.50% convertible unsecured subordinated debentures of the Corporation issued pursuant to the 7.50% Debenture Indenture;

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

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

"**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;

"**Exchangeable Shares**" means the series A exchangeable shares in the capital of True Energy which were exchangeable for Trust Units;

"**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.

"**net**" means:

(d) 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.

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

(f) 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*;

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

"**Sproule Report**" means the report of Sproule dated February 24, 2012 evaluating our crude oil, natural gas liquids and natural gas reserves as at December 31, 2011;

"**True**" or the "**Trust**" means True Energy Trust, a trust established under the laws of Alberta;

"**True Energy**" means True Energy Inc., a corporation amalgamated pursuant to the ABCA, which was the administrator of the Trust;

"**Trust Unit**" or "**Unit**" means a unit of the Trust;

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

"**TUSK**" means TUSK Energy Inc., a corporation incorporated under the ABCA that changed its name to TKE Energy Inc. on December 14, 2004 and amalgamated with True Energy Inc. pursuant to the 2005 Arrangement and continued under the name True Energy Inc.

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, 2010.

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, 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 be forward-looking statements. Words such as "may", "will", "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" 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 or information are based on a number of factors and assumptions which have been used to develop such statements and information but which may prove to be incorrect. Although Bellatrix believes that the expectations reflected in such forward-looking statements or information 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 and other information 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 the Trust pursuant to the 2009 Arrangement. Under the Arrangement, True Energy 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.

Bellatrix's principal and head office is located at 2300, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8 and its registered office is located at 2400, 525 – 8th Ave SW Calgary, AB T2P 1G1.

Bellatrix does not have, and at December 31, 2011 did not have, any material subsidiaries.

The Common Shares and 4.75% Debentures trade on the TSX under the symbols "BXE" and "BXE.DB.A", respectively.

GENERAL DEVELOPMENT OF OUR BUSINESS

The following is a summary description of the development of our business.

2009 Arrangement – Transformation to a Corporation

Effective November 1, 2009, Bellatrix completed a plan of arrangement under the ABCA involving True Energy, the Trust and certain subsidiaries of the Trust and securityholders of the Trust, pursuant to which Bellatrix, directly or indirectly, acquired all of the assets and assumed all of the liabilities, respectively, of the Trust. Prior to completion of the 2009 Arrangement, the Trust was a reporting issuer in certain provinces of Canada and the Trust Units were listed for trading on the TSX. Following completion of the 2009 Arrangement, the Trust Units were de-listed from trading on the TSX and the Trust ceased to be a reporting issuer.

Pursuant to the terms of the 2009 Arrangement, former holders of Trust Units received one Common Share for each one Trust Unit held and former holders of Exchangeable Shares received Common Shares based on the exchange ratio for the Exchangeable Shares in effect on completion of the 2009 Arrangement. The former securityholders of the Trust received an aggregate 78,809,039 Common Shares in exchange for all the outstanding Trust Units and Exchangeable Shares.

In connection with the completion of the 2009 Arrangement, Bellatrix assumed all of the covenants and obligations of the Trust under the outstanding 7.50% Debentures which following the 2009 Arrangement were convertible into Common Shares, rather than Trust Units, at the same conversion price that previously existed for the Trust Units, being a conversion price of $16.00 per Common Share, subject to adjustment as provided in the 7.50% Debenture Indenture.

Pre-2009 Arrangement

The TKE Energy Trust was created on November 2, 2004 pursuant to the 2004 Arrangement which resulted in, among other things, the conversion of TUSK into the TKE Energy Trust, a new oil and natural gas energy trust. On November 2, 2005, the 2005 Arrangement was completed pursuant to which, among other things, (i) all of the outstanding common shares of True Energy were acquired by the Trust, (ii) the name of the Trust was changed from "TKE Energy Trust" to "True Energy Trust" and (iii) the outstanding Trust Units were consolidated on a one for two basis. The following is summary of the development of the business of the Trust from January 1, 2009 to the 2009 Arrangement.

2009 Asset Divestitures

On July 30, 2009, the Trust completed the divestiture (the "**Pre-2009 Arrangement Divestitures**") of the majority of its oil and natural gas assets in Saskatchewan for net proceeds of $85 million, after closing adjustments, effective May 1, 2009. The divestiture excluded the Saskatchewan properties of Cypress and Mantario. The Trust's interest to the base Belly River in three sections in the Ferrier area of West Central Alberta was also disposed of in the transaction. The assets sold included production estimated to average 3,000 BOE/d in Q3 and Q4 in 2009, including 5.3 MMcf/d of natural gas, 128 km² of 3D proprietary seismic with 389.7 km of 2D proprietary seismic, subject to a royalty free license on the seismic in favour of True, and 63,333 net acres of undeveloped mineral leases. Effective June 1, 2009, in a separate transaction to a private buyer, the Trust sold 145 BOE/d of production, including 0.63 MMcf/d of natural gas, in the Penhold Area of Central Alberta for $4.7 million, after closing adjustments. In addition, in June 2009, the Trust completed a disposition of certain royalty interests for approximately $3.7 million, after purchase adjustments and closing costs. Proceeds from the Pre-2009 Arrangement Divestitures were utilized to reduce bank indebtedness. Upon closing of the Pre-2009 Arrangement Divestitures, Bellatrix had 270,651 net acres of undeveloped land. The Pre-2009 Arrangement Divestitures reduced sales volumes by approximately 3,600 BOE/d for the third and fourth quarters of 2009.

Post 2009 Arrangement

2010 Public Offering of Common Shares

On January 28, 2010, the Corporation completed a public offering of an aggregate of 13,640,000 Common Shares at a price of $3.30 per Common Share for aggregate gross proceeds of $45,012,000.

2010 Public Offering of 4.75% Debentures and Redemption of 7.50% Debentures

On April 20, 2010, the Corporation completed a public offering of 4.75% Debentures having an aggregate principal amount of $55,000,000. The proceeds from the issuance of the 4.75% Debentures were used to partially fund the redemption of the 7.50% Debentures and the balance of the redemption amount was funded through bank indebtedness. The 7.50% Debentures were redeemed by the Corporation on July 2, 2010 for an amount of $1,025 for each $1,000 principal amount of the 7.50% Debentures plus accrued and unpaid interest.

2010 Private Placement of Flow-Through Shares

On August 12, 2010, the Corporation completed a private placement of an aggregate of 4,710,000 Common Shares issued on a "flow-through" basis at a price of $4.25 per share for aggregate gross proceeds of $20,017,500.

2010 Asset Divestiture

On December 22, 2010, the Corporation completed the sale of its interest in a non-core property at Mantario, Saskatchewan for net proceeds of $13.6 million after adjustments. The property had annual production of 290 BOE/d that consisted primarily of heavy oil. The effective date of the sale was December 1, 2010.

2011 Public Offering of Common Shares

On May 11, 2011, the Corporation completed a public offering of an aggregate of 9,822,000 Common Shares at a price of $ 5.60 per Common Share for aggregate gross proceeds of $55,003,200.

2011 Asset Acquisitions and Divestitures

On January 25, 2011, Bellatrix acquired the interest in a section of Frog Lake First Nation lands from a joint venture partner for a net purchase price of $2.2 million after adjustments. The transaction had an effective date of January 1, 2011. At the time of acquisition, the net production on the acquired lands was 130 BOE/d. The acquisition resulted in Bellatrix acquiring an additional 20% working interest in the Colony formation (Bellatrix already had a 13.75% working interest) and an additional 50% working interest in the McLaren formation (Bellatrix already has a 50% working interest) except for a quarter section (in which Bellatrix already had a 13.75% working interest) in the acquired lands.

On January 25, 2011, Bellatrix exercised a right of first refusal increasing its interest in a joint venture property in the Brazeau area of West Central Alberta for approximately $1.5 million. The asset acquisition consisted of approximately 3,200 gross (1,102.8 net) acres of Cardium rights providing the Corporation with up to 6.3 additional net Cardium drilling locations and included 15 BOE/d of production.

During the second quarter of 2011, Bellatrix closed two transactions consisting of the sale of a minor property interest of 160 gross (14 net) acres of land in Saskatchewan and a swap of interests where Bellatrix increased its Cardium exposure in 3.5 gross (1.7 net) sections in the Greater Pembina area. There was no production associated with the acreages sold in the second quarter of 2011.

Effective September 22, 2011, the Corporation completed the sale of its interest in a non-core property at Meekwap, Alberta for net proceeds of $4.2 million after adjustments. The property had production of approximately 65 BOE/d that consisted primarily of light oil.

Significant Acquisitions

We did not complete any significant acquisitions during our most recently completed financial year for which disclosure is required under Part 8 of NI 51-102.

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. 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. Bellatrix 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 drilling or acquisition 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.

With Bellatrix's improved financial flexibility, management plans to seek opportunities to consolidate assets that complement its focused asset base either through geographic fit, technical expertise or future development potential.

Bellatrix may, 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 24, 2012. The effective date of the Statement is December 31, 2011 and the preparation date of the Statement is February 24, 2012.

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, 2011 contained in the Sproule Report. 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 and 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 our independent qualified reserves evaluators in Form 51-101F2 are attached as Schedule "A" and Schedule "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, 2011
FORECAST PRICES AND COSTS

	Light And Medium Oil		Heavy Oil		Conventional Natural Gas		Natural Gas Liquids		Coal Bed Methane	
Reserves Category	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**	**Gross (Mbbls)**	**Net (Mbbls)**	**Gross (MMcf)**	**Net (MMcf)**
Proved Developed Producing	4,380	3,333	646	550	70,070	55,983	2409	1,534	1,137	951
Proved Developed Non-Producing	35	32	-	-	2,125	1,646	50	31	-	-
Proved Undeveloped	4,425	3,541	210	149	84,812	62,325	3,250	2,201	-	-
Total Proved	8,840	6,905	856	699	157,007	119,953	5790	3,766	1,137	951
Probable	5,704	4,238	375	311	95,189	71,880	3,668	2,389	372	311
Total Proved Plus Probable	14,543	11,143	1,231	1,010	252,196	191,834	9,377	6,156	1,509	1,262

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	478,179	368,145	303,900	261,766	231,921	478,719	368,146	303,900	261,766	231,921	20.39	3.40
Proved Developed Non–Producing	7,321	5,380	4,190	3,416	2,886	7,321	5,380	4,190	3,416	2,886	12.42	2.07
Proved Undeveloped	398,527	248,347	163,001	109,404	73,334	301,592	193,288	128,714	86,660	57,527	10.01	1.67
Total Proved	884,567	621,873	471,092	374,586	308,141	787,632	566,814	436,804	351,843	292,334	14.94	2.49
Probable	733,346	392,434	251,454	177,814	133,231	550,005	292,691	186,034	130,253	96,481	13.26	2.21
Total Proved Plus Probable	1,617,913	1,014,307	722,546	552,400	441,373	1,337,637	859,505	622,838	482,095	388,815	14.31	2.39

Note:

(1) Unit values are based upon net reserves.

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2011 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	2,311,550	529,424	614,853	264,166	18,538	884,567	96,935	787,632
Proved Plus Probable	3,981,436	939,469	1,023,572	376,771	23,710	1,617,913	280,276	1,337,637

FUTURE NET REVENUE BY PRODUCTION GROUP AS OF DECEMBER 31, 2011 FORECAST PRICES AND COSTS

Reserves Category	Production Group	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)	238,238	$23.46/BOE
	Heavy Oil (including solution gas and other by-products)	15,277	$21.74/BOE
	Natural Gas (including by–products but excluding solution gas from oil wells)	216,292	$10.55/BOE
	Non-conventional oil and gas activities	1,286	$8.12/BOE
	Total	471,093	$14.94/BOE
Proved Plus Probable	Light and Medium Crude Oil (including solution gas and other by–products)	350,235	$20.00/BOE
	Heavy Oil (including solution gas and other by-products)	20,714	$20.42/BOE
	Natural Gas (including by–products but excluding solution gas from oil wells)	349,994	$11.02/BOE
	Non-conventional oil and gas activities	1,603	$7.62/BOE
	Total	722,546	$14.31/BOE

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.

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; and
- specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

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

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

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

Other criteria that must also be met for the categorization of reserves are provided in 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 presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

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

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

A 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 mathematically derived 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 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. 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 January 1, 2012, which are as follows:

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS

Year	OIL: WTI Cushing Oklahoma ($US/Bbl)	OIL: Edmonton Par Price 40° API ($Cdn/Bbl)	OIL: Hardisty Heavy 12° API ($Cdn/Bbl)	NATURAL GAS AECO Price ($Cdn/MMBtu)	NATURAL GAS LIQUIDS at Edmonton ($Cdn/Bbl)	INFLATION RATES(1) %/Year	EXCHANGE RATE(2) ($US/$Cdn)
Forecast							
2012	97.52	97.94	74.59	3.38	105.78	2.0	1.012
2013	97.47	97.92	72.19	4.04	104.14	2.0	1.012
2014	97.33	97.80	69.98	4.47	102.28	2.0	1.012
2015	99.41	99.85	74.10	5.23	104.48	2.0	1.012
2016	100.36	100.79	75.58	5.57	105.47	2.0	1.012
2017	101.35	101.78	77.09	5.88	106.53	2.0	1.012
2018	102.78	103.21	78.64	6.12	108.06	2.0	1.012
2019	104.44	104.88	80.21	6.26	109.80	2.0	1.012
2020	106.14	106.58	81.81	6.43	111.81	2.0	1.012
2021	108.29	108.77	83.45	6.57	113.92	2.0	1.012
2022	110.44	110.92	85.12	6.69	116.17	2.0	1.012
2023	112.68	113.13	86.82	6.81	118.47	2.0	1.012
2024	114.89	115.40	88.56	6.95	120.85	2.0	1.012
2025	117.19	117.70	90.33	7.10	123.27	2.0	1.012
2026	119.59	120.07	92.13	7.25	125.26	2.0	1.012
Thereafter	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	+2%/year	

Notes:

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

Weighted average historical prices realized by Bellatrix before hedging for the year ended December 31, 2011, were $3.77/Mcf for natural gas, $92.51/Bbl for light and medium gravity crude oil, $68.23 for heavy oil and $53.54/Bbl for natural gas liquids.

Reconciliation of Changes in Reserves

The following table sets out the reconciliation of our gross reserves as at December 31, 2011 compared to December 31, 2010 based on forecast prices and costs by principal product type:

FACTORS	LIGHT AND MEDIUM OIL: Gross Proved (Mbbl)	LIGHT AND MEDIUM OIL: Gross Probable (Mbbl)	LIGHT AND MEDIUM OIL: Gross Proved Plus Probable (Mbbl)	HEAVY OIL: Gross Proved (Mbbl)	HEAVY OIL: Gross Probable (Mbbl)	HEAVY OIL: Gross Proved Plus Probable (Mbbl)	CONVENTIONAL NATURAL GAS: Gross Proved (MMcf)	CONVENTIONAL NATURAL GAS: Gross Probable (MMcf)	CONVENTIONAL NATURAL GAS: Gross Proved Plus Probable (MMcf)
December 31, 2010(1)	6,465	5,566	12,031	445	208	653	90,353	59,932	150,284
Discoveries	-	-	-	-	-	-	-	-	-
Extensions	2,949	2,615	5,564	65	14	79	53,045	42,423	95,468
Infill Drilling	889	556	1,444	-	-	-	7,175	7,121	14,296
Improved Recovery	-	-	-	-	-	-	-	-	-
Technical Revisions	(333)	(2,970)	(3,302)	272	106	378	22,503	(14,249)	8,254
Acquisitions	39	16	55	190	47	236	59	25	84
Dispositions	(127)	(79)	(206)	-	-	-	(157)	(63)	(221)
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(1,043)	-	(1,043)	(115)	-	(115)	(15,970)	-	(15,970)
December 31, 2011(2)	8,840	5,703	14,543	856	376	1,231	157,007	95,189	252,196

FACTORS	NATURAL GAS LIQUIDS Gross Proved (Mbbl)	Gross Probable (Mbbl)	Gross Proved Plus Probable (Mbbl)	COAL BED METHANE Gross Proved (MMcf)	Gross Probable (MMcf)	Gross Proved Plus Probable (MMcf)
December 31, 2010 [(1)]	2,601	1,778	4,379	1,632	360	1,991
Discoveries	-	-	-	-	-	-
Extensions	2,066	1,623	3,689	-	-	-
Infill Drilling	301	362	663	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	1,237	(94)	1,144	(296)	13	(283)
Acquisitions	3	1	4	-	-	-
Dispositions	(6)	(3)	(9)	-	-	-
Economic Factors	-	-	-	-	-	-
Production	(494)	-	(494)	(199)	-	(199)
December 31, 2011[(2)]	5,709	3,668	9,377	1,137	372	1,509

Note:

(1) As evaluated by GLJ Petroleum Consultants Ltd. in a report dated February 22, 2011 and effective as of December 31, 2011.

(2) 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, 2011, 2010 and 2009 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)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)		Coal Bed Methane (MMcf)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
Prior thereto	211	211	2,505	2,505	9,002	9,002	182	182	52	52
2009	345	751	57	617	2,506	9,346	100	269	-	40
2010	3,742	3,742	60	60	23,399	27,969	902	961	-	121
2011	2,552	4,425	30	210	49,804	84,812	1,919	3,250	-	-

Probable Undeveloped Reserves

Year	Light and Medium Oil (Mbbl)		Heavy Oil (Mbbl)		Conventional Natural Gas (MMcf)		NGLs (Mbbl)		Coal Bed Methane (MMcf)	
	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End	First Attributed	At Year End
Prior thereto	367	367	4,706	4,706	17,521	17,521	423	423	32	32
2009	178	379	98	293	1,373	15,725	47	440	-	51
2010	3,600	4,191	90	90	24,025	34,200	933	1,167	-	18
2011	2,924	3,458	5	120	46,531	65,527	1,843	2,654	-	-

Proved Undeveloped Reserves

A total of 84,812 MMcf of natural gas, 4,635 Mbbl of oil and 3,250 Mbbl of NGLs were assigned as proved undeveloped reserves as at December 31, 2011, representing approximately 53% of our total proved reserves. 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. The proved undeveloped reserves are generally associated with infill/development drilling locations supported by offset well data. The largest portion of the capital associated with developing proved undeveloped reserves is expected to be spent in 2012 and 2013 with residual spending until 2021. With respect to capital development costs associated with proved undeveloped reserves in the Sproule Report, approximately 80% of the capital is scheduled to be spent over the next two years and 99.8% is scheduled to be spent over the next four 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 Pembina, Brazeau and Ferrier and represents 96% of all assigned proven future development capital. Eighty percent of the proved activity is expected in the next two years and all activity is booked over the next three. 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 operating or 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.

Probable Undeveloped Reserves

A total of 66,527 MMcf of natural gas, 3,578 Mbbl of oil and 2,655 Mbbl of NGLs were assigned as gross probable undeveloped reserves in 2011, representing approximately 67% of our total probable reserves or 26% 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. Some probable undeveloped reserves attributed require joint venture partner approval for development. Generally, Bellatrix attributes reserves as probable undeveloped reserves rather than proved undeveloped reserves in cases where Bellatrix cannot directly control the timing and execution of development of the reserves. 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 2012 to 2014. With respect to capital development costs associated with probable undeveloped reserves in the Sproule Report, approximately 84% of the capital is scheduled to be spent over the next two years and

99.6% is scheduled to be spent over the next four 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.

Significant Factors or Uncertainties

While we do not anticipate any significant economic factors or significant 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)**
2012	109,208	165,689
2013	98,738	137,266
2014	55,494	72,647
2015	97	541
2016	-	-
Thereafter	628	628
Total: Undiscounted	264,166	376,771

We expect to be able to fund our capital expenditure program, including estimated future development costs, using cash flow from operations and available credit facilities. Equity financing may also be used to fund operations. If cash flows are other than projected, capital expenditure levels will 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.

The expected costs of funding our capital expenditures have been built into the economics of the programs and the reserves evaluation.

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, 2011. Unless otherwise indicated, production stated is average daily production for the year ended December 31, 2011 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, Notikewin, Falher and Rock Creek zones at depths ranging from 1,800 to 2,700 metres. Area production averaged 4,140 BOE/d in 2011, comprised of 81% natural gas, 11% natural gas liquids and 8% light oil and condensate. The gas is currently processed at third party facilities. However, the Corporation has acquired working interests in two major gas processing facilities at Ferrier which will reduce operating expenses and guarantee access to gas markets. Bellatrix's land holdings in the area were 20,918 gross (9,480 net) acres of developed land and 33,236 gross (28,605 net) acres of undeveloped land as at December 31, 2011.

Bellatrix drilled or participated in a total of 16 gross liquids rich Cardium and Notikewin-Falher horizontal gas wells (8.6 net) at Ferrier and Alder Flats in 2011, which included 3 gross (3.0 net) Cardium gas wells and 8 gross (3.5 net) Notikewin-Falher gas wells operated by the Corporation, and an additional 5 gross (2.1 net) participating non-operated liquids rich Notikewin-Falher gas wells (2.1 net).

The 3 gross (3.0 net) Cardium wells drilled by the Corporation at Ferrier during 2011 at a success rate of 100% have been completed and tied in during November of 2011.

Of the 8 gross (3.5 net) liquids rich Notikewin-Falher horizontal gas wells drilled by the Corporation at Ferrier during 2011, 7 gross (3.3 net) were completed and tied in during 2011using multi-staged fracture stimulation. One gross well (0.2 net) was completed and tied in January 2012.

To date in 2012 at Ferrier, the Corporation has drilled and completed 1 gross (1.0 net) liquids rich Cardium horizontal gas well (1.0 net) and participated in 1 gross (0.5 net) non-operated horizontal Notikewin-Falher gas well. The Cardium well has been tied and is expected to be placed on production in February 2012 and the Notikewin-Falher gas well is currently being completed and expected to be tied and placed on production in March 2012.

The Corporation plans to drill between 8 and 10 gross Cardium (8.0 to 10.0 net) horizontal wells at Ferrier in the remainder of 2012. Bellatrix could also drill up to 4 additional Notikewin-Falher tests in the third or fourth quarter of 2012 (2.7 net) at Alder Flats in 2012.

Bellatrix has amassed a significant contiguous block of Duvernay rights at Ferrier in 2011. Two parcels of lands with Duvernay rights were acquired in 2011 that have a total area of 41 gross (41 net) sections. Bellatrix is currently drilling a 5,117 meter Duvernay horizontal test at 8-24-44-10 W5M to evaluate the liquids rich gas prospect. At Alder Flats, the Corporation holds additional Duvernay rights on an adjacent 2 gross (2.0 net) sections. The Corporation plans to drill a second exploratory test at Alder Flats in the third quarter of 2012. In total, the Corporation has an interest in 44 gross (43 net) sections of Duvernay rights.

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 and liquids-rich natural gas from zones in the Notikewin, Falher, Ellerslie, and Rock Creek 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 in 2011 averaged 2,183 BOE/d, consisting of 58% natural gas, 33% light oil and condensate and 9% natural gas liquids. The majority of this production is operated by Bellatrix. Bellatrix held 28,960 gross (16,074 net) acres of developed land and 4,320 gross (2,653 net) acres of undeveloped land in the area as at December 31, 2011.

Bellatrix drilled and completed a total of 5 gross (3.6 net) Cardium oil wells at Willesden Green in 2011. All of the wells were tied in during 2011.

Bellatrix owns interests in and operates three compressor stations. Although the liquids rich gas currently produced from this area is processed to pipeline specification at third party plants, Bellatrix has signed an agreement that will provide it with a working interest in a gas plant that currently processes natural gas production from the area.

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. In 2011, area production averaged 2,624 BOE/d, consisting of 21% natural gas, 76% light oil and condensate, and 3% natural gas liquids. Bellatrix production is processed at third party gas plants. Bellatrix held 28,263 gross (12,924 net) acres of developed land and 10,160 gross (4,378 net) acres of undeveloped land in this area as at December 31, 2011.

Bellatrix operated or participated in the drilling of a total of 22 gross (14.4 net) Cardium horizontal wells in the Pembina area at Lodgepole, West Pembina and Buck Creek during 2011 with a success rate of 100%, which included 11 gross (9.5 net) Cardium horizontal oil wells drilled and completed by the Corporation at Lodgepole, 3 gross (2.2 net) Cardium horizontal oil wells drilled and completed by the Corporation at West Pembina, 1 gross (0.9 net) Cardium horizontal well drilled and completed by the Corporation at Buck Creek, and 7 gross (1.9 net) non-operated Cardium horizontal oil wells at West Pembina.

The 11 gross (9.5 net) Cardium horizontal oil wells drilled, completed and tied in by the Corporation. All 10 gross (4.1 net) Cardium horizontal oil wells in which the Corporation drilled or participated in West Pembina were placed on production in 2011.

Bellatrix plans to drill 5 gross (3.3 net) Cardium horizontal oil wells at Lodgepole in 2012, of which 1 gross (0.3 net) has successfully been drilled, completed and placed on production. Bellatrix expects to drill 3 gross (2.1 net) Cardium horizontal oil wells at West Pembina in 2012, of which 1 gross (0.8 net) has been drilled and cased.

Brazeau

The Brazeau area is located approximately 50 kilometres southwest of Drayton Valley, Alberta. Bellatrix's land holdings were 10,560 gross (6,147 net) acres of developed land and 9,600 gross (7,738 net) acres of undeveloped land as at December 31, 2011. In 2011, production averaged 880 BOE/d consisting of 64% natural gas, 4% natural gas liquids and 32% light oil and condensate. Principal formations are the Cardium, Viking, Notikewin, Falher and Rock Creek zones at depths of 2,450 metres and 2,700 metres. Production is routed to existing third party facilities in the area for processing.

Bellatrix drilled 6 gross (5.0 net) horizontal Cardium oil wells at Brazeau in 2011. The wells were completed using a slick water fracture technique and subsequently tied in. Bellatrix participated in one gross (0.3 net) non-operated horizontal Cardium oil well in the fourth quarter of 2011. The well has been completed and is currently awaiting to be tied in.

Bellatrix anticipates drilling 5 gross (4.7 net) Cardium horizontal tests in 2012 to develop the resource potential on its Brazeau lands.

Northern Alberta and British Columbia

The Corporation maintains three shallow gas properties in Northern Alberta and British Columbia; however there are no plans for additional development of these at this time.

The Saddle Lake and Whitefish Lake properties are located in the vicinity of St. Paul, Alberta, on the Saddle Lake First Nation and the Whitefish Lake First Nation northeast of Edmonton. Bellatrix holds a 50% interest in a joint venture with Keyano Pimee Exploration Corporation Ltd., a corporation that is owned by the Saddle Lake and Whitefish Lake First Nations. The leases on the joint venture lands provide for payment of royalties to Indian Oil and Gas Canada ("**IOGC**"). The royalties payable to IOGC are Alberta Crown equivalent, calculated using the rules and regulations applicable to Alberta Crown royalties.

The Corporation has identified additional drilling and optimization opportunities but has chosen to defer additional development until such time that netbacks improve. In 2011, production for the Saddle Lake and Whitefish Lake properties averaged 445 BOE/d from natural gas wells ranging in depth from 550 to 700 metres. The area features multiple productive horizons that include some non-producing reserves waiting on favourable gas pricing. Bellatrix operates all the wells and three compressor/dehydrator stations in the area. The property is comprised of 24,796 gross (12,270 net) acres of developed land and 9,760 gross (5,520 net) acres of undeveloped land.

The Doris property is located 160 kilometres northwest of Edmonton, Alberta. In 2011, production averaged 137 BOE/d, primarily from natural gas. Doris is prospective in multiple zones including a coal bed methane zone which is offsetting a major Corporation's development project at Corbett Creek. Production is compressed at a Bellatrix owned compressor for delivery to a joint interest non-operated processing facility in which Bellatrix owns an interest. Bellatrix's land holdings were 32,640 gross (29,657 net) acres of developed land and 30,240 gross (24,896 net) acres of undeveloped land in this area as at December 31, 2011. The Corporation has no near term plans for additional drilling at Doris.

South East and Central Alberta and South West Saskatchewan

Bellatrix's properties in South East and Central Alberta and South West Saskatchewan include five producing areas: Rattlesnake, Cypress, Irvine, Faith and Siksika. Rattlesnake is the largest of the five natural gas producing areas and is located approximately 40 kilometres southwest of Medicine Hat. The Second White Specks is one of the key producing horizons in southern Alberta. The Medicine Hat and Milk River formations also significantly contribute to production. In 2011, production averaged 930 BOE/d from predominately shallow natural gas. Bellatrix operates booster compression and gathering systems in this area which delivers gas to a joint interest non-operated processing facility. As at December 31, 2011, Bellatrix's land holdings were 111,633 gross (80,252 net) acres of developed land and 65,989 gross (61,172 net) acres of undeveloped land in South East and Central Alberta and South West Saskatchewan.

Additional drilling plans will be determined by commodity pricing in 2012.

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, 2011.

	Oil Wells				**Natural Gas Wells**			
	Producing		**Non-Producing**		**Producing**		**Non-Producing**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Saskatchewan	-	-	-	-	15	15	18	18
Alberta	350	116	95	25	937	512	172	116
British Columbia	-	-	-	-	19	6	8	4
Total	350	116	95	25	971	533	198	138

Developed and Undeveloped Lands

The following table sets out our developed and undeveloped land holdings as at December 31, 2011.

	Developed Acres		**Undeveloped Acres**		**Total Acres**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	370,653	209,786	198,777	152,363	569,429	362,149
British Columbia	19,850	7,315	143,968	60,590	163,818	67,905
Saskatchewan	13,327	12,720	11,606	11,606	24,934	24,326
Total	403,830	229,821	354,351	224,559	758,181	454,380

Note:

(1) May not add due to rounding.

As at December 31, 2011, Bellatrix committed to drill 4 gross (3.17 net) wells pursuant to farm-in agreements. Bellatrix expects to satisfy these drilling commitments at an estimated cost of approximately $10.8 million. In addition, on February 1, 2011, Bellatrix entered into a joint venture agreement which includes a minimum commitment for the Corporation to drill 3 gross (3.0 net) wells per year for 2011 to 2015 for a total estimated cost of approximately $52.5 million. As at December 31, 2011, 12 wells remained to be drilled under this commitment for a total estimated cost of $42.0 million. On August 4, 2011, Bellatrix entered in a joint venture agreement which includes a minimum commitment for the Corporation to drill between 5 to 10 gross and net wells per year for 2011 to 2016 for a total of 40 gross and net wells at an estimated cost of approximately $140.0 million, with the first five wells requiring completion by November of 2012. In respect of the February 1, 2011 joint venture agreement, the Corporation also committed to drilling 1 gross (1.0 net) test well at an estimated cost of $7.8 million.

Potentially, approximately 7% of our mineral rights could expire by December 31, 2012 as a result of those rights reaching maximum land tenure. 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.

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 63% of total crude oil and natural gas liquids production and an average of 31% of total natural gas production during the twelve months ended December 31, 2011. The following provides details of the commodity price risk management arrangements outstanding as at December 31, 2011 and as of the date hereof.

As at December 31, 2011, the Corporation has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Crude oil fixed	January 1, 2012 to Dec. 31, 2012	1,000 Bbls/d	$ 90.00 CDN	$ 90.00 CDN	WTI
Crude oil fixed	January 1, 2012 to Dec. 31, 2012	1,000 Bbls/d	$ 90.49 CDN	$ 90.49 CDN	WTI
Crude oil fixed	January 1, 2012 to Dec. 31, 2012	1,000 Bbls/d	$ 96.40 CDN	$ 96.40 CDN	WTI
Crude oil call option	January 1, 2012 to Dec. 31, 2012	833 Bbls/d	-	$ 110.00 US	WTI
Crude oil call option	January 1, 2013 to Dec. 31, 2013	1,000 Bbls/d	-	$ 110.00 US	WTI
Natural gas fixed	April 1, 2012 to Oct. 31, 2012	10,000 GJ/d	$ 4.10 CDN	$ 4.10 CDN	AECO

Subsequent to December 31, 2011, the Corporation has entered into commodity price risk management arrangements as follows:

Type	Period	Volume	Price Floor	Price Ceiling	Index
Crude oil call option	January 1, 2013 to Dec. 31, 2013	1,000 Bbls/d	-	$ 110.00 US	WTI
Crude oil call option	January 1, 2013 to Dec. 31, 2013	1,000 Bbls/d	-	$ 110.00 US	WTI
Natural gas fixed	April 1, 2012 to Oct. 31, 2012	10,000 GJ/d	$ 4.10 CDN	$ 4.10 CDN	AECO
Natural gas fixed	April 1, 2012 to Oct. 31, 2012	10,000 GJ/d	$ 4.11 CDN	$ 4.11 CDN	AECO

Additional Information Concerning Abandonment and Reclamation Costs

We have included the estimated future well abandonment costs for existing and future reserves wells in the economic forecasts. 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 reserve 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 $18.5 million ($5.0 million discounted at 10%) and $23.7 million ($4.5 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)**
2012	146	73
2013	138	87
2014	369	272
Subtotal	653	432
Remainder	17,885	23,278
Total (Undiscounted)	18,538	23,710
Total discounted at 10%	5,047	4,527

We currently have 1026.0 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, 2011, 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 $50.7 million, of which $45.1 million has been recorded. 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 2011 fiscal year. Depending on production, commodity prices and capital spending levels, management believes that the Corporation will not begin paying current income taxes until 2013 or beyond.

Capital Expenditures

The following table summarizes capital expenditures (excludes non-cash expenditures relating to asset retirement obligations, capitalized unit based compensation and capital leases) related to our assets and activities for the year ended December 31, 2011:

		$000's
Property acquisition costs		
Proved properties		3,798
Undeveloped properties		16,367
Exploration costs		433
Development costs		159,522
Drilling incentive credits		(827)
Dispositions		(4,203)
Corporate Assets		268
Total	$	175,358

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, 2011.

	Exploratory Wells		Development Wells	
	Gross	**Net**	**Gross**	**Net**
Light and Medium Oil	5	4.7	32	22.3
Natural Gas	-	-	14	5.8
Heavy Oil	-	-	2	2.0
Service	-	-	-	-
Stratigraphic Test	-	-	-	-
Dry	-	-	1	0.0
Total	5	4.7	49	30.1

For details on the important current and likely exploration and development activities during 2010, 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, 2012, 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	3,237	333	52,478	2,019	14,335
Total Proved Plus Probable	3,576	377	69,811	2,923	18,512

Note:

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

The Ferrier property in the West Central area accounts for 9,892 BOE/d, or 53% of the estimated total production. 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			
	2011			
	Dec. 31	**Sept. 30**	**June 30**	**Mar. 31**
Average Daily Production[(1)]				
Light and Medium Crude Oil (Bbls/d)	3,925	3,365	3,335	3,301
Heavy Oil (Bbls/d)	322	245	423	273
Natural Gas (Mcf/d)[(2)]	52,734	44,546	43,157	37,346
NGLs (Bbls/d)	1,173	803	692	556
Combined (BOE/d)	14,209	11,837	11,643	10,084

	Quarter Ended			
	2011			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Price Received				
Light and Medium Crude Oil ($/Bbl)	95.18	88.91	100.88	83.75
Heavy Oil ($/Bbl)	74.30	64.19	71.46	59.55
Natural Gas ($/Mcf)(2)	3.30	3.91	4.06	3.94
NGLs ($/Bbl) (3)	54.31	51.74	56.15	51.27
Combined ($/BOE)	44.69	44.83	49.87	44.20
Royalties Paid				
Light and Medium Crude Oil ($/Bbl)	14.49	14.92	18.46	11.42
Heavy Oil ($/Bbl)	30.21	18.54	39.15	29.16
Natural Gas ($/Mcf)(2)	0.36	0.44	0.72	0.51
NGLs ($/Bbl)	8.26	23.47	14.96	18.59
Combined ($/BOE)	6.71	7.88	10.25	7.13
Operating Expenses				
Light and Medium Crude Oil ($/Bbl)	14.14	14.21	13.94	14.70
Heavy Oil ($/Bbl)	19.24	34.69	11.61	32.03
Natural Gas ($/Mcf)(2)	1.55	1.64	1.76	1.79
NGLs ($/Bbl)	8.14	11.37	9.15	9.99
Combined ($/BOE)	10.78	11.71	11.50	12.45
Netback Received before Transportation				
Light and Medium Crude Oil ($/Bbl)	66.55	59.79	68.48	57.63
Heavy Oil ($/Bbl)	24.84	10.96	20.70	(1.64)
Natural Gas ($/Mcf)(2)	1.38	1.83	1.58	1.64
NGLs ($/Bbl)	37.91	16.91	32.04	22.69
Combined ($/BOE)	27.21	25.24	28.11	24.62
Transportation Costs				
Light and Medium Crude Oil ($/Bbl)	2.01	2.50	3.17	1.90
Heavy Oil ($/Bbl)	2.54	0.96	0.44	0.43
Natural Gas ($/Mcf)(2)	0.16	0.16	0.13	0.19
NGLs ($/Bbl)	-	-	-	-
Combined ($/BOE)	1.21	1.34	1.42	1.29
Netback Received after Transportation (4)				
Light and Medium ($/Bbl)	64.55	57.29	65.31	55.73
Heavy Oil ($/Bbl)	22.30	10.00	20.26	(2.07)
Natural Gas ($/Mcf)(2)	1.22	1.67	1.45	1.45
NGLs ($/Bbl)	37.91	16.91	32.04	22.69
Combined ($/BOE)	26.00	23.89	26.70	23.33

Notes:

(1) Includes minor royalty volumes received but does not deduct royalty volumes paid.
(2) Includes minor amounts of coal bed methane production.
(3) NGL pricing excludes pentanes.
(4) 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, 2011. Company share production includes minor royalty volumes received but does not deduct royalty volumes paid.

	Light and Medium Crude Oil (Bbls/d)	Heavy Oil (Bbls/d)	Condensate (Bbls/d)	Natural Gas (Mcf/d)	NGLs (Bbls/d)	BOE (BOE/d)
West Central Alberta Region						
Ferrier	29	-	322	20,106	438	4,140
Greater Pembina	1,936	-	57	3,288	83	2,624
Willesden Green	609	-	107	7,631	195	2,183
Brazeau	234	-	42	3,394	38	880
Other Properties	(1)	-	13	715	39	170
	2,807	-	541	35,134	793	9,997
Northern Region and British Columbia						
Saddle Lake & Whitefish Lake	-	-	-	2,667	-	445
Doris	-	-	-	811	2	137
Other Properties	(5)	241	5	1,181	7	445
	(5)	241	5	4,659	9	1,027
South East and Central Alberta and South West Saskatchewan	64	75	4	4,691	6	930
TOTALS[(1)]	2,866	316	550	44,484	808	11,954

Note:

(1) May not add due to rounding.

Crude oil production from our assets for the year ended December 31, 2011 was 90% light and medium quality crude oil (25° API or greater) and 10% heavy crude oil (less than 15° API).

For the twelve months ended December 31, 2011, approximately 69% of gross revenue from our assets was derived from crude oil and natural gas liquids production and 31% was derived from natural gas production.

DIVIDENDS AND DISTRIBUTIONS

Dividend History

Bellatrix has not paid any dividends on the outstanding Common Shares. The Board of Directors of Bellatrix 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 of Directors of Bellatrix 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 of Directors of Bellatrix considers relevant. Bellatrix's current credit facility does not permit payment of dividends on the outstanding Common Shares.

Distribution History

Prior to the completion of the 2009 Arrangement, historically, monthly cash distributions were paid by the Trust to holders of Trust Units; however, distributions were suspended February 9, 2009 and no distributions were paid thereafter. The last cash distribution paid by the Trust (and the only cash distribution paid by the Trust in 2009) was a $0.02 cash distribution paid per Trust Unit in January 2009.

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 of Directors of Bellatrix 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 trade under the symbol "BXE". The following table sets forth the price range and trading volume of the Common Shares on the TSX (as reported by such exchange) for the periods indicated.

Period	High ($)	Low ($)	Volume
2011			
January	5.25	4.61	4,266,310
February	6.19	5.05	18,584,553
March	5.90	5.06	11,047,471
April	5.96	5.48	19,685,391
May	5.49	4.78	15,600,942
June	5.45	4.48	9,669,965
July	5.48	4.58	9,978,560
August	4.96	3.59	8,809,404
September	4.62	3.35	7,468,687
October	4.89	3.15	14,065,173
November	5.00	4.31	6,725,282
December	5.05	4.49	4,610,124
2012			
January	5.10	4.36	11,429,179
February	5.67	4.66	16,385,652
March (1 - 14)	5.64	5.12	6,699,412

4.75% Debentures

The 4.75% Debentures are listed for trading on the TSX and trade under the symbol "BXE.DB.A". The following table sets forth the high and low trading prices and trading volume of the 4.75% Debentures on the TSX (with each unit of volume traded being equal to $100 principal amount for each 4.75% Debenture) for the periods indicated.

Period	High ($)	Low ($)	Volume
2011			
January	109.20	103.10	22,824
February	125.00	109.01	45,510
March	122.00	111.69	11,920
April	122.00	116.50	19,355
May	116.50	110.00	7,275
June	115.00	105.00	3,930
July	117.91	107.50	3,900
August	108.45	97.00	17,080
September	104.75	92.19	23,980
October	117.70	91.00	39,730
November	111.14	102.00	25,070
December	108.50	104.75	32,505
2012			
January	111.22	104.39	7,490
February	117.50	107.99	14,520
March (1 - 14)	117.50	115.16	20,230

ESCROWED SECURITIES

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

BORROWINGS

Senior Credit Facilities

As at December 31, 2011 and as at the date hereof, the Corporation's credit facilities consist of a $15 million demand operating facility provided by one Canadian bank and a $155 million extendible revolving term credit facility provided by two Canadian banks and one Canadian financial institution (collectively the "**Credit Facilities**"). The extendible revolving term facility would be payable 365 days after the term-out date, if such term-date is not extended by the lenders. Amounts borrowed under the Credit Facilities bear interest at a floating rate, with the margin over the Canadian prime rate, U.S. base rate or LIBOR margin rate, or the bankers' acceptance stamping fee, as applicable being between 1.0% and 3.50%, depending on the type of borrowing and the debt to cash flow ratio. A standby fee is charged of between 0.50% and 0.875% on the undrawn portion of the Credit Facilities, depending on the Corporation's debt to cash flow ratio. The Credit Facilities are secured against all of the assets of the Corporation by a $400 million debenture containing a first ranking charge and security interest. The Corporation has provided a negative pledge and undertaking to provide fixed charges over major petroleum and natural gas reserves in certain circumstances. The amount available under the Credit Facilities is not to exceed the borrowing base, which is currently $170 million. The borrowing base will be subject to re-determination on May 31 and November 30 in each year prior to the maturity, with the next semi-annual redetermination occurring on or before May 31, 2012.

Debentures

On April 20, 2010 the Corporation completed a public offering of 4.75% Debentures by way of short form prospectus for aggregate gross proceeds of $55 million. The 4.75% Debentures have a face value of $1,000 per Debenture and have a maturity date of April 30, 2015 (the "**Maturity Date**"). The payment of the principal and premium, if any, of, and interest on, the 4.75% Debentures is subordinated in right of payment to the prior payment in full of all "Senior Indebtedness" of the Corporation which includes all obligations, liabilities and indebtedness of the Corporation and its subsidiaries which would, in accordance with generally accepted accounting principles be classified as a liability of the Corporation and its subsidiaries, unless it is expressly stated to be subordinated and ranked *pari passu* with the 4.75% Debentures.

The 4.75% Debentures are convertible at the holder's option at any time prior to the close of business on the earlier of the business day immediately preceding the Maturity Date and the date specified by the Corporation for redemption of the 4.75% Debenture into Common Shares at a conversion price of $5.60 per Common Share (the "**Conversion Price**").

The 4.75% Debentures are not redeemable by the Corporation before April 30, 2013. On and after April 30, 2013 and prior to April 30, 2014, the 4.75% Debentures are redeemable at the Corporation's option, in whole or in part, at par plus accrued and unpaid interest if the weighted average trading price of the Common Shares for the specified period is not less than 125% of the Conversion Price. On and after April 30, 2014, the 4.75% Debentures are redeemable at the Corporation's option, in whole or in part, at any time at par plus accrued and unpaid interest.

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

Within 30 days following the occurrence of a "Change of Control" of the Corporation, the Corporation will be required to make an offer (the "**Change of Control Purchase Offer**") in writing to purchase all of the Debentures then outstanding (the "**Debenture Offer**"), at a price equal to 100% of the principal amount thereof plus accrued and unpaid interest thereon. If 90% or more of the aggregate principal amount of the Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered to the Corporation pursuant to the Debenture Offer, the Corporation will have the right to redeem all the remaining Debentures at the same offer price. For this purpose, a Change of Control of the Corporation is deemed to have occurred upon (i) the acquisition by any person, or group of persons acting jointly or in concert (within the meaning of Multilateral Instrument 62-104), of voting control or direction of an aggregate of more than 50% of the outstanding Common Shares; or (ii) the sale of all or substantially all of the assets of the Corporation, but shall not include a sale, merger, reorganization, combination or other similar transaction where the previous holders of Common Shares hold at least 50% of the voting control or direction in such merged, reorganized, combined or other continuing entity (or, in the case of a sale of all or substantially all of the assets, in the entity which has acquired such assets).

In addition, in the event of a Change of Control occurs in which 10% or more of the consideration for the Common Shares in the transaction or transactions constituting the Change of Control consists of cash (other than payment for fractional Common Shares or cash payments made in satisfaction of appraisal rights), equities, securities or other properties not traded or intended to be traded immediately following such transaction on a stock exchange, then during the period beginning 10 trading days after the anticipated date that such Change of Control becomes effective and ending 30 days after the Change of Control Purchase Offer is delivered, holders of the 4.75% Debentures will be entitled to convert the debentures at an adjusted conversion price which will be adjusted based on a formula dependent on the then current trading price and the remaining period up to but excluding April 30, 2014.

The following table summarizes certain terms of the Debentures including the principal amount outstanding as of March 13, 2012:

Maturity Date	Interest Rate at Date of Issue	Principal Amount Outstanding	Conversion Price per Common Share	Number of Common Shares Reserved
April 30, 2015	4.75%	$55,000,000	$5.60	9,821,429

For a complete description of the terms of the 4.75% Debentures, a copy of the 4.75% Debenture Indenture has been filed on www.sedar.com under the Corporation's SEDAR profile.

DIRECTORS AND OFFICERS

The following table sets forth the name, age (as at December 31, 2011), 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. Palm Desert, California, United States of America Age: 64	President, Chief Executive Officer and Director	April 25, 2005	President and Chief Executive Officer of Bellatrix and prior to the 2009 Arrangement of True Energy since January 26, 2009, Chairman of Madalena Ventures Inc. since October 2005. Prior thereto, 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.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director[1]	Principal Occupation
Edward J. Brown, C.A. Calgary, Alberta, Canada Age: 56	Vice-President, Finance and Chief Financial Officer	N/A	Vice-President, Finance and Chief Financial Officer of Bellatrix and prior to the 2009 Arrangement of True Energy since July 4, 2006; 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.
Ving Y. Woo, P. Eng. Calgary, Alberta, Canada Age: 63	Vice President and Chief Operating Officer	N/A	Vice-President and Chief Operating Officer of Bellatrix since October 2010 and prior thereto Vice President, Operations of Bellatrix and prior to the 2009 Arrangement of True Energy since April 2009. Currently director of Madalena Ventures Inc. since March 2006 and formerly a Director of Cork Exploration Inc., a public oil and gas company. Formerly Vice President, Engineering for Meridian Energy Corp. from September 2002 until March 2005.
Russell G. Oicle **P. Geol.** Calgary, Alberta, Canada Age: 56	Vice-President, Exploration	N/A	Vice-President, Exploration of Bellatrix and prior to the 2009 Arrangement of True Energy 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: 53	Vice President, Land	N/A	Vice President, Land of Bellatrix and prior to the 2009 Arrangement of True Energy since October 2009; prior thereto was Vice President, Land for Terra Energy Corp. from June 2004 to September 2009
Garrett Ulmer Calgary, Alberta, Canada Age: 41	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, or prior to the 2009 Arrangement, True Energy, since January 2008.
W.C. (Mickey) Dunn Calgary, Alberta, Canada Age: 58	Chairman[4][5]	August 31, 2000	Chairman of Bellatrix and prior to the 2009 Arrangement of True Energy; Director of Precision Drilling Inc.; Director of The Cash Store Financial Services Inc.; 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.

Name, Municipality of Residence and Age	Position with Bellatrix	Date First Elected or Appointed as Director(1)	Principal Occupation
Doug N. Baker, FCA Calgary, Alberta, Canada Age: 58	Director(2)(5)	April 26, 2007	Independent businessman. Mr. Baker currently serves as Chair of the Board of Directors of Genesis Land Development Corp. and Chair of the Audit Committee for ATB Financial Ltd., Winstar Resources Ltd., RMP Energy Inc., Longview Oil Corp., and Century Energy Ltd. Served as Chair of the Canadian Institute of Chartered Accountants from October 2008 to 2010.
Murray L. Cobbe Calgary, Alberta, Canada Age: 62	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).
John H. Cuthbertson, Q.C. Calgary, Alberta, Canada Age: 61	Director(5)	August 31, 2000	Partner, Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Murray B. Todd, B. Sc. P. Eng. Calgary, Alberta, Canada Age: 76	Director(3)	November 2, 2005	President of Canada Hibernia Holding Corporation (an oil and gas production company).
Melvin M. Hawkrigg, BA, FCA, LL.D. (Hon.) Waterdown, Ontario, Canada Age: 81	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: 75	Director(3)	September 21, 2009	Independent businessman. Executive Vice-President of Grey Wolf Exploration Inc. from 2000 to July 2009.
Keith E. Macdonald, C.A. Calgary, Alberta, Canada Age: 55	Director(2)(4)	April 26, 2007	President of Bamako Investment Management Ltd., a private holding and financial consulting company, since July 1994.

Notes:

(1) Reflects the date of election or appointment as Director of True Energy.
(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.

As at February 29, 2012, the directors and officers of Bellatrix, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 1,995,849 Common Shares, representing approximately 1.86% of the issued and outstanding Common Shares.

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.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate and Terms of Reference

The Mandate of the Audit Committee of the board of directors of Bellatrix is attached hereto as Schedule "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 Chair of the Board of Directors of Genesis Land Development Corp. and Chair of the Audit Committee for ATB Financial Ltd., Winstar Resources Ltd., RMP Energy Inc., Longview Oil Corp. 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 Chairman and director of Cirrus Energy Ltd. and a director of Cordy Oilfield Services Inc., Holloman Energy Corp., Madalena Ventures Inc.,

Name and municipality of residence	Independent	Financially literate	Relevant education and experience
			Mountainview Energy Ltd., Rocky Mountain Dealerships Inc., Stratabound Minerals Inc., Surge Energy Inc. and WCSB Oil & Gas Royalty Income 2010 Management Corp., which is the general partner of WCSB Oil & Gas Royalty Income 2010 Limited Partnership. Mr. MacDonald is a Chartered Accountant.

Pre-Approval of Policies and Procedures

The Audit Committee has pre-approved the provision of certain non-audit services to the Corporation including assorted income tax services including compliance and routine planning matters and has delegated to the Chairman of the Audit Committee the authority to pre-approve other non-audit services and in such event the Chairman is required to report to the Audit Committee such pre-approval at the next meeting of the Audit Committee. The engagement may commence upon approval of the Chairman of the Audit Committee.

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, a Saskatchewan properties audit, a plan of arrangement, reviews of interim consolidated financial statements, international financial reporting standards and due diligence work in respect of financings were $351,390 in 2011 and $543,914 in 2010.

Audit – Related Fees

There were $52,530 in 2011 and $102,822 in 2010 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

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the external auditor for tax compliance, tax advice and tax planning were $Nil in 2011 and $Nil in 2010.

All Other Fees

No other professional services fees were billed by the external auditor for other non-audit related fees in 2011 or 2010.

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 and 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. It is not expected that any of these regulations or controls will affect the Corporation's operations in a manner materially different than they will affect other oil and natural gas companies of similar size. 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

The producers of oil are entitled to negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Oil prices are primarily based on worldwide supply and demand. The specific price depends in part on oil quality, prices of competing fuels, distance to market, value of refined products, the supply/demand balance and contractual terms of sale. Oil exporters are also entitled to enter into export contracts with terms not exceeding one year in the case of light crude oil and two years in the case of heavy crude oil, provided that an order approving such export has been obtained from the National Energy Board of Canada (the "**NEB**"). Any oil export to be made pursuant to a contract of longer duration (to a maximum of 25 years) requires an exporter to obtain an export licence from the NEB.

Natural Gas

The price of the vast majority of natural gas produced in western Canada is now determined through highly liquid market hubs such as the Alberta "NIT" (Nova Inventory Transfer) hub rather than through direct negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas (other than propane, butane and ethane) exports for a term of less than two years or for a term of two to 20 years (in quantities of not more than 30,000 m^3/day) must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or for a larger quantity requires an exporter to obtain an export licence from the NEB.

The governments of Alberta, British Columbia and Saskatchewan also regulate the volume of natural gas that may be removed from those provinces for consumption elsewhere based on such factors as reserve availability, transportation arrangements and market considerations.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico became effective on January 1, 1994. In the context of energy resources, Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of the party maintaining the restriction as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. All three signatory countries are prohibited from imposing a minimum or maximum export price requirement in any circumstance where any other form of quantitative restriction is prohibited. The signatory countries are also prohibited from imposing a minimum or maximum import price requirement except as permitted in enforcement of countervailing and anti-dumping orders and undertakings. NAFTA requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of those changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements, all of which are important for Canadian oil and natural gas exports.

Royalties and Incentives

General

In addition to federal regulation, each province has legislation and regulations which govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects, crude oil, natural gas liquids, sulphur and natural gas production. Royalties payable on production from lands other than Crown lands are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, 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 was set at 40%. The royalty curve for conventional oil announced on May 27, 2010 amends the price component of the conventional oil royalty formula to moderate the increase in the royalty rate at prices higher than $\$535/m^3$ compared to the previous royalty curve.

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 was set at 36%. The royalty curve for natural gas announced on May 27, 2010 amends the price 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.

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

Producers of oil and natural gas from freehold lands in Alberta are required to pay annual freehold production taxes. The level of the freehold production tax is based on the volume of monthly production and a specified rate of tax for both oil and gas.

The Innovative Energy Technologies Program (the "**IETP**"), which is currently in place, 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 and are intended to encourage the development of deeper, higher cost oil and 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 November 19, 2008, the Government of Alberta announced the introduction of a five-year program of transitional royalty rates with the intent of promoting new drilling. The five-year transition option is designed to provide lower royalties at certain price levels in the initial years of a well's life when production rates are expected to be the highest. Under this program, companies drilling new natural gas or conventional deep oil wells (between 1,000 and 3,500 m) are given a one-time option, on a well-by-well basis, to adopt either the new transitional royalty rates or those outlined in the royalty regime. These options expired on February 15, 2011 and on January 1, 2014, all producers operating under the transitional royalty rates will automatically become subject to the royalty regime. The revised royalty curves for conventional oil and natural gas will not be applied to production from wells operating under the transitional royalty rates.

On March 3, 2009, the Government of Alberta announced a three-point incentive program in order to stimulate new and continued economic activity in Alberta. One aspect of the program was a drilling royalty credit program which provided up to a $200 per metre royalty credit for new wells. The drilling credit program applied to wells that were drilled between April 1, 2009 and March 31, 2010 and has not been extended for wells drilled after March 31, 2010. Another aspect of the program was a new well royalty program which provided for a maximum 5% royalty rate for eligible new wells for the first twelve (12) productive months or until the regulated "volume cap" was reached. The *New Well Royalty Regulation*, providing for the permanent implementation of this incentive program, was approved by an Order-in-Council on March 17, 2011.

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

- Coalbed methane wells will receive a maximum royalty rate of 5% for 36 producing months on up to 750 MMcf of production, retroactive to wells that began producing on or after May 1, 2010;
- Shale gas wells will receive a maximum royalty rate of 5% for 36 producing months with no limitation on production volume, retroactive to wells that began producing on or after May 1, 2010;
- Horizontal gas wells will receive a maximum royalty rate of 5% for 18 producing months on up to 500 MMcf of production, retroactive to wells that commenced drilling on or after May 1, 2010; and
- Horizontal oil wells and horizontal non-project oil sands wells will receive a maximum royalty rate of 5% with volume and production month limits set according to the depth of the well (including the horizontal distance), retroactive to wells that commenced drilling on or after May 1, 2010.

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

British Columbia

Producers of oil and natural gas from Crown lands in British Columbia are required to pay annual rental payments, currently at a rate of $3.50 per hectare, 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 based on the determination of whether the oil is produced from a pool discovered before October 31, 1975 ("old oil"), between October 31, 1975 and June 1, 1998 ("new oil"), or after June 1, 1998 ("third-tier oil"). 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 as an incentive for the production and marketing of natural gas which might otherwise have been flared.

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. For natural gas, the freehold production tax 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.

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

- *Summer Royalty Credit Program* providing a royalty credit of 10% of drilling and completion costs up to $100,000 for wells drilled between April 1 and November 30 of each year, intended to increase summer drilling activity, employment and business opportunities in northeastern British Columbia;

- *Deep Royalty Credit Program* providing a royalty credit equal to approximately 23% of 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 2,300 metres;

- *Deep Re-Entry Royalty Credit Program* providing royalty credits for deep re-entry wells with a true vertical depth greater than 2,300 metres and a re-entry date subsequent to December 1, 2003;

- *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 with a spud date after November 30, 2003;

- *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 royalty reductions for low productivity natural gas wells with average monthly production under 25,000 m^3 during the first 12 production months and average daily production less than 23 m^3 for every metre of marginal well depth;

- *Ultra-Marginal Royalty Reduction Program* providing additional royalty reductions for low productivity shallow natural gas wells with a true vertical depth of less than 2,500 metres in the case of vertical wells, and a total vertical depth of less than 2,300 metres in the case of a horizontal well, average monthly production under 60,000 m^3 during the first 12 production months and average daily production less than 11.5 m^3 (development wells) or 17 m^3 (exploratory wildcat wells) for every 100 metres of marginal well depth; 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 (the "**Infrastructure Royalty Credit Program**") which provides royalty credits for up to 50% of the cost of certain approved road construction or pipeline infrastructure projects intended to improve, or make possible, the access to new and underdeveloped oil and gas areas. In 2009, 2010 and 2011, the Government of British Columbia awarded $120 million in royalty credits to oil and gas companies under the Infrastructure Royalty Credit Program.

On August 6, 2009, the Government of British Columbia announced an oil and gas stimulus package designed to attract investment in and create economic benefits for British Columbia. The stimulus package includes four royalty initiatives related primarily to natural gas drilling and infrastructure development. British Columbia's existing Deep Royalty Credit Program was permanently amended for wells spudded after August 31, 2009 by increasing the royalty deduction on deep drilling for natural gas by 15% and extending the program to include horizontal wells drilled to depths of between 1,900 and 2,300 metres. An additional $50 million was also allocated to be distributed through the Infrastructure Royalty Credit Program to stimulate investment in oilfield-related road and pipeline construction.

Saskatchewan

In Saskatchewan, the amount payable as Crown royalty or 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 classified as "heavy oil", "southwest designated oil" or "non-heavy oil other than southwest designated oil". The conventional royalty and production tax classifications ("fourth tier oil", "third tier oil", "new oil" and "old oil") depend on the finished drilling date of a well and are applied to each of the three crude oil types slightly differently. Heavy oil is classified as third tier oil (having a finished drilling date on or after January 1, 1994 and before October 1, 2004), fourth tier oil (having a finished drilling date on or after October 1, 2002) or new oil (not classified as either third tier oil or fourth tier oil). Southwest designated oil uses the same definitions of third and fourth tier oil but 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 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, whereas old oil is defined as conventional oil not classified as third or fourth tier oil or new oil.

Base prices are used to establish lower limits in the price-sensitive royalty structure for conventional 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 Crown royalty or freehold production tax in respect of natural gas production is determined by a sliding scale based on the actual price received, the quantity produced in a given month, the type of natural gas, and the vintage of the natural gas. Like conventional oil, natural gas may be classified as "non-associated gas" or "associated gas" and royalty rates are determined according to the finished drilling date of the respective well. As an incentive for the production and marketing of natural gas which may have been flared, the royalty rate on natural gas produced in association with oil is less than on non-associated natural gas. 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 more than 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* replacing the existing *Freehold Oil and Gas Production Tax Act* with the intention to facilitate more efficient payment of freehold production taxes by industry. No regulations have been passed with respect to the calculation of freehold production taxes under the new legislation, although several regulations remain in force under the previous legislation.

As with conventional oil production, base prices 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 \$50 per thousand m^3 for third and fourth tier gas and \$35 per thousand m^3 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 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 and freehold tax rates 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);

- *Royalty/Tax Incentive Volumes for Exploratory Gas Wells Drilled on or after October 1, 2002* providing reduced Crown royalty and freehold tax rates 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 and freehold tax rates 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 or within certain formations);

- *Royalty/Tax Incentive Volumes for Horizontal Gas Wells drilled on or after June 1, 2010 and before April 1, 2013* providing reduced Crown royalty and freehold tax rates on incentive volumes of 25,000,000 m^3 for horizontal gas wells;

- *Royalty/Tax Regime for Incremental Oil Produced from New or Expanded Waterflood Projects Implemented on or after October 1, 2002* treating incremental production from waterflood projects as fourth tier oil for the purposes of royalty calculation;

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

- *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 enhanced oil recovery projects pre-payout and 20% post-payout and a freehold production tax of 0% on operating income from enhanced oil recovery projects pre-payout and 8% post-payout; and

- *Royalty/Tax Regime for High Water-Cut Oil Wells* granting "third tier oil" royalty/tax rates to incremental high water-cut oil production resulting from qualifying investments made to rejuvenate eligible oil wells and/or associated facilities.

In 1975, the Government of Saskatchewan introduced a Royalty Tax Rebate ("**RTR**") as a response to the Government of Canada disallowing crown royalties and similar taxes as a deductible business expense for income tax purposes. As of January 1, 2007, the remaining balance of any unused RTR will be limited in its carry forward to seven years since the Government of Canada's initiative to reintroduce the full deduction of provincial resource royalties from federal and provincial taxable income. Saskatchewan's RTR will be wound down as a result of the Government of Canada's plan to reintroduce full deductibility of provincial resource royalties for corporate income tax purposes.

On June 22, 2011, the Government of Saskatchewan released the Upstream Petroleum Industry Associated Gas Conservation Standards which are designed to reduce emissions resulting for 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 is set to commence on July 1, 2012 for new wells and facilities licensed on or after such date, and to apply to existing licensed wells and facilities on July 1, 2015.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. 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. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are granted by lease on such terms and conditions as may be negotiated.

Each of the provinces of Alberta, British Columbia and Saskatchewan has implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or license. On March 29, 2007, British Columbia's policy of deep rights reversion was expanded 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. Holders of leases or licences that have been continued indefinitely prior to January 1, 2009 will receive a notice regarding the reversion of the shallow rights, which will be implemented three years from the date of the notice. Leases and licences that were granted prior to January 1, 2009 but continued after that date are not subject to shallow rights reversion until they reach the end of their primary term and are continued (at which time deep rights reversion will be applied); thereafter, the holders of such agreements will be served with shallow rights reversion notices based on vintage and location similar to leases and licences that were already continued as of January 1, 2009. The order in which these agreements will receive reversion notices will depend on their vintage and location, and the Government of Alberta had anticipated that the receipt of reversion notices for older leases and licenses would commence in April 2011. However, on April 14, 2011, the Government of Alberta announced it was deferring serving shallow rights reversion notices and will revisit the decision in spring 2012.

Environmental Regulation

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of provincial and federal legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations, such as sulphur dioxide and nitrous oxide. In addition, such legislation requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, and the imposition of material fines and penalties.

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 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.

The *Alberta Land Stewardship Act* (the "**ALSA**") was proclaimed in force in Alberta on October 1, 2009 and provides the legislative authority for the Government of Alberta to implement the policies contained in the ALUF. Regional plans established pursuant to the ALSA will be 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, leases, licenses, 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 29, 2011 the Government of Alberta released a revised draft of the Lower Athabasca Regional Plan (the "**Revised LARP**") updating its prior draft of April 5, 2011 (the "**Draft LARP**"). The Revised LARP, while establishing several conservation areas of the Athabasca region, has changed the boundaries of certain conservation areas outlined in the Draft LARP with the result that fewer oil sands leases appear to be impacted. Consistent with the Draft LARP, as the intention of the Revised LARP is to manage the areas to minimize or prevent new land disturbance, activities associated with oil sands development are considered incompatible with the intent to manage such conservation areas. However, references to the cancellation of existing tenures have been removed from the Revised LARP and the Revised LARP now contemplates that the conservation areas will be created pursuant to existing legislation rather than the previously contemplated regulations. Existing conventional petroleum and natural gas rights will not be affected, although the Revised LARP raises some question as to whether new conventional leases and licenses will be granted in the conservation areas in the future. The planning process is also underway for a regional plan for the South Saskatchewan Region.

Climate Change Regulation

Federal

In December 2002, the Government of Canada ratified the Kyoto Protocol ("**Kyoto Protocol**"), which requires a reduction in greenhouse gas ("**GHG**") emissions by signatory countries between 2008 and 2012. The Kyoto Protocol officially came into force on February 16, 2005 although on December 12, 2011 Canada formally withdrew from the Kyoto Protocol.

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 which will be applied to regulated sectors on either a facility-specific, sector-wide or company-by-company basis. Facility-specific targets apply to the upstream oil and gas, oil sands, petroleum refining and natural gas pipelines sectors. Unless a minimum regulatory threshold applies, all facilities within a regulated sector will be subject to the emissions intensity targets.

The Updated Action Plan makes a distinction between "Existing Facilities" and "New Facilities". For Existing Facilities, the Updated Action Plan requires an emissions intensity reduction of 18% below 2006 levels by 2010 followed by a continuous annual emissions intensity improvement of 2%. "New Facilities" are defined as facilities beginning operations in 2004 and include both greenfield facilities and major facility expansions that (i) result in a 25% or greater increase in a facility's physical capacity, or (ii) involve significant changes to the processes of the facility. New Facilities will be given a 3-year grace period during which no emissions intensity reductions will be required. Targets requiring an annual 2% emissions intensity reduction will begin to apply in the fourth year of commercial operation of a New Facility. Further, emissions intensity targets for New Facilities will be based on a cleaner fuel standard to encourage continuous emissions intensity reductions over time. The method of applying this cleaner fuel standard has not yet been determined. In addition, the Updated Action Plan indicates that targets for the adoption of carbon capture and storage ("**CCS**") technologies will be developed for oil sands in-situ facilities, upgraders and coal-fired power generators that begin operations in 2012 or later. These targets will become operational in 2018, although the exact nature of the targets has not yet been determined.

Given the large number of small facilities within the upstream oil and gas and natural gas pipeline sectors, facilities within these sectors will only be subject to emissions intensity targets if they meet certain minimum emissions thresholds. That threshold will be (i) 50,000 tonnes of CO_2 equivalents per facility per year for natural gas pipelines; (ii) 3,000 tonnes of CO_2 equivalents per facility per year for the upstream oil and gas facility; and (iii) 10,000 boe/d/company. These regulatory thresholds are significantly lower than the regulatory threshold in force in Alberta, discussed below. In all other sectors governed by the Updated Action Plan, all facilities will be subject to regulation.

Four separate compliance mechanisms are provided for in the Updated Action Plan in respect of the above targets:

(a) Regulated entities will be able to use Technology Fund contributions to meet their emissions intensity targets. The contribution rate for Technology Fund contributions will increase over time, beginning at $15 per tonne of CO_2 equivalent for the 2010 to 2012 period, rising to $20 in 2013, and thereafter increasing at the nominal rate of GDP growth. Maximum contribution limits will also decline from 70% in 2010 to 0% in 2018. Monies raised through contributions to the Technology Fund will be used to invest in technology to reduce GHG emissions. Alternatively, regulated entities may be able to receive credits for investing in large-scale and transformative projects at the same contribution rate and under similar requirements as described above.

(b) The offset system is intended to encourage emissions reductions from activities outside of the regulated sphere, allowing non-regulated entities to participate in and benefit from emissions reduction activities. In order to generate offset credits, project proponents must propose and receive approval for emissions reduction activities that will be verified before offset credits will be issued to the project proponent. Those credits can then be sold to regulated entities for use in compliance or non-regulated purchasers that wish to either purchase the offset credits for cancellation or banking for future use or sale.

(c) Under the Updated Action Plan, regulated entities were able to purchase credits created through the Clean Development Mechanism of the Kyoto Protocol which facilitates investment by developed nations in emissions-reduction projects in developing countries. The purchase of such Emissions Reduction Credits will be restricted to 10% of each firm's regulatory obligation, with the added restriction that credits generated through forest sink projects will not be available for use in complying with the Canadian regulations. However, with the recent withdrawal from the Kyoto Protocol, the future use of this mechanism may not occur.

(d) Finally, a one-time credit of up to 15 million tonnes worth of emissions credits will be awarded to regulated entities for emissions reduction activities undertaken between 1992 and 2006. These credits will be both tradable and bankable.

From December 7 to 18, 2009, government leaders and representatives met in Copenhagen, Denmark and agreed to the Copenhagen Accord, which reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Another meeting of government leaders and representatives in 2010 resulted in the Cancun Agreements wherein developed countries committed to additional measures to help developing countries deal with climate change. Neither the Copenhagen Accord nor the Cancun Agreements establish binding GHG emissions reduction targets. In response to the Copenhagen Accord, the Government of Canada indicated that it will seek to achieve a 17% reduction in GHG emissions from 2005 levels by 2020.

Although draft regulations for the implementation of the Updated Action Plan were intended to become binding on January 1, 2010, only draft regulations pertaining to carbon dioxide emissions from coal-fired generation of electricity have been proposed to date. Further, 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. As a result, it is unclear to what extent, if any; the proposals contained in the Updated Action Plan will be implemented.

The United States Environmental Protection Agency (the "**EPA**") has indicated its intention to impose GHG emissions standards for fossil fuel-fired power plants by specifying that it will issue final regulations by May 26, 2012, and with respect to refineries, specifying that it will issue proposed regulations by December 10, 2011 and finalized regulations by November 10, 2012. The EPA did not meet the December 10, 2011 deadline and it is unclear whether the EPA will also miss the finalized regulations deadline.

Alberta

Alberta enacted the *Climate Change and Emissions Management Act* (the "**CCEMA**") on December 4, 2003, amending it 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 similar to the Updated Action Plan and aims for a 50% reduction from 1990 emissions relative to GDP by 2020.

Alberta facilities emitting more than 100,000 tonnes of GHGs a year are subject to compliance with the CCEMA. Similar to the Updated Action Plan, the CCEMA and the associated *Specified Gas Emitters Regulation* make a distinction 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 to 88% of their baseline for 2008 and subsequent years, with their baseline being established by the average of the ratio of the total annual emissions to production for the years 2003 to 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 *Specified Gas Emitters Regulation*. New Facilities are required to reduce their emissions intensity by 2% from baseline in the fourth year of commercial operation, 4% of baseline in the fifth year, 6% of baseline in the sixth year, 8% of baseline in the seventh year, and 10% of baseline in the eighth year. Unlike the Updated Action Plan, the CCEMA does not contain any provision for continuous annual improvements in emissions intensity reductions beyond those stated above.

The CCEMA contains compliance mechanisms that are similar to the Updated Action Plan. Regulated emitters can meet their emissions intensity targets by contributing to the Climate Change and Emissions Management Fund (the "**Fund**") at a rate of $15 per tonne of CO_2 equivalent. Unlike the Updated Action Plan, CCEMA contains no provisions for an increase to this contribution rate. Emissions credits can 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.

On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*, which 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 $25 per tonne of CO2 equivalent. It is scheduled to increase to $30 per tonne of CO2 equivalent on July 31, 2012. 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.

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. 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. Although more specific details of British Columbia's cap and trade plan have not yet been finalized, on January 1, 2010, new reporting regulations came into force requiring all British Columbia facilities emitting over 10,000 tonnes of CO2 equivalents per year to begin reporting their emissions. Facilities reporting emissions greater than 25,000 tonnes of CO2 equivalents per year are required to have their emissions reports verified by a third party. Regulations pertaining to proposed offsets and emissions trading are currently in the consultation stage.

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. Regulations under the MRGGA have also yet to be proclaimed, but draft versions indicate that Saskatchewan will adopt the goal of a 20% reduction in GHG emissions from 2006 levels by 2020 and permit the use of pre-certified investment credits, early action credits and emissions offsets in compliance, similar to both the federal and Alberta 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.

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, any existing reserves the Corporation may have at any particular time, and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Corporation's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Corporation will be able to continue to locate satisfactory properties for acquisition or participation therein. Moreover, if such acquisitions or participations are identified, management of the Corporation may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Corporation.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also 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 or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including fire, explosion, blowouts, cratering, sour gas releases, spills or other environmental hazards, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, 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. In accordance with 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, the nature of certain risks is such that liabilities could exceed policy limits or not be covered, in either event the Corporation could incur significant costs.

Global Financial Crisis

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 conditions have caused a decrease in confidence in the 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. This volatility may in the future affect the Corporation's ability to obtain equity or debt financing on acceptable terms.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by numerous factors beyond its control. 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. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any 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 as a result 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 of 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. 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 of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. 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 as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions, and sanctions imposed on certain oil producing nations by other countries and the 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. This volatility is often based on factors both related and unrelated to the financial performance or prospects of the issuers involved. 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. Factors that could affect the market price of the Common Shares that are unrelated to the Corporation's performance include domestic and global commodity prices and market perceptions of the attractiveness of particular industries. 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 in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as 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 and may divert 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 that 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, could be expected to 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. As a result, 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 therefore depends upon a number of factors that may be outside of the Corporation's control, including 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 within 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;
- changes in regulations;
- 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 not be able to effectively market the oil and natural gas that it produces.

Gathering and Processing Facilities and Pipeline Systems

The Corporation delivers its products through gathering, processing 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, processing and pipeline systems. The lack of availability of capacity in any of the gathering, processing and pipeline systems, 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. 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.

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 materially adversely affect the Corporation's ability to process its production and to deliver the same for sale.

Competition

The petroleum industry is competitive in all 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 and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. See "Industry Conditions". Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political 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 licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate hydrocarbon (oil and natural gas) production. The use of hydraulic fracturing is being used to produce 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 or 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. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such 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 regulations, 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.

Climate Change

The Corporation's exploration and production facilities and other operations and activities emit greenhouse gases and require the Corporation to comply with greenhouse gas emissions legislation in Alberta or that may be enacted in other provinces. The Corporation may also be required comply with the regulatory scheme for greenhouse gas emissions ultimately adopted by the federal government, which regulations are expected to be consistent with the regulatory scheme for greenhouse gas emissions adopted by the United States. The direct or indirect costs of these regulations may have a material adverse effect on the Corporation's business, financial condition, results of operations and prospects. The future implementation or modification of greenhouse gases regulations, whether to meet the limits regulated by the Copenhagen Accord or as otherwise determined, could have a material impact on the nature of oil and natural gas operations, including those of the Corporation. 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. See "*Industry Conditions – Climate Change Regulation*".

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Material increases in the value of the Canadian dollar negatively impact the Corporation's production revenues. Future Canadian/United States exchange rates could accordingly impact 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, which could negatively impact the market price of the Common Shares of the Corporation.

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, tax burden due to new 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. As a result of the global economic volatility, the Corporation, along with many other oil and natural gas entities, 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 or 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 materially and adversely affected 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 amounts authorized under the Credit Facilities are dependent on the borrowing base determined by its lenders. The Corporation is required to comply with covenants under the Credit Facilities and in the event that the Corporation does not comply therewith the Corporation's access to capital could be restricted or repayment could be required. The failure of the Corporation to comply with such covenants, which may be affected by events beyond the Corporation's control, could result in the default under the Credit Facilities which could result in the Corporation being required to repay amounts owing thereunder. 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, 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 facility may, from time to time, 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, 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 borrowing base is determined and re-determined by the Corporation's lenders based on the Corporation's reserves, commodity prices, applicable discount rate and other factors as determined by the Corporation's lenders. A material decline in commodity prices could reduce the Corporation's borrowing base, therefore reducing the funds available to the Corporation under the Credit Facilities which could result in a portion, or all, of the Corporation's bank indebtedness be required to be repaid.

See "*Borrowings – Senior Credit Facilities*"

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;
- 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 in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, 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.

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 to defeat the Corporation's claim 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 proposed legislative changes which affect title, to the oil and natural gas properties the Corporation controls that, if successful or made into law, 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 herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom 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, 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 thereof and such variations could be material.

Estimates 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 and 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 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 has not been updated and thus 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.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Corporation is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil. Conflicts, or conversely peaceful developments, arising in the Middle East, North Africa and other areas of the world have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore 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 subject to 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 may be 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.

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 of directors of the Corporation considers relevant.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to 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.

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. Also, certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and corresponding declines in the demand for the goods and services of the Corporation.

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 impact 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 of the Corporation are also directors of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of 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.

HUMAN RESOURCES

As at December 31, 2011 we employed 66 full-time employees (53 are located in the head office and 13 are field employees) and 38 consultants (34 full-time and 4 part-time consultants of which 7 are located in the head office and 31 are in the field).

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of directors or executive officers of True Energy or 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 the Trust or 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, Chartered Accountants, the Corporation's auditors, are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

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 2011 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, 2011, 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, other than the 4.75% Debenture Indenture.

A copy of this document has been filed on SEDAR at www.sedar.com.

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 and Debentures.

ADDITIONAL INFORMATION

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

Bellatrix Exploration Ltd.
Suite 2300, 530 - 8th Avenue S.W.
Calgary, Alberta T2P 3S8
Tel: (403) 266-8670
Fax: (403) 264-8163

SCHEDULE "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, 2011 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 14th day of March, 2012.

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

(signed) "*Edward J. Brown*"
Edward J. Brown, C.A.
Vice-President, Finance and Chief Financial Officer

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

(signed) "*Robert A. Johnson*"
Robert A. Johnson
Director

SCHEDULE "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, 2011. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2011 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**") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions 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 Corporation evaluated by us as of December 31, 2011, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $M)			
Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Audited	Evaluated	Reviewed	Total
Sproule Associates Limited	Evaluation of the P&NG Reserves of Bellatrix Exploration Ltd., As of December 31, 2011, Using Consensus Pricing, prepared December 2011 to February 2012	Canada	-	$722,546	-	$722,546

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 reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

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

EXECUTED as to our report referred to above:

Sproule Associates Limited
Calgary, Alberta
February 24, 2012

Per: (signed) "*Meghan M. Klein, P. Eng.*"
Petroleum Engineer and Partner

Per: (signed) "*James E. Nemrava, R.E.T.*"
Senior Petroleum Technologist and Partner

Per: (signed) "*Lucia M. Precul, P. Eng.*"
Senior Petroleum Engineer and Partner

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

Per: (signed) "*Harry J. Helwerda, P. Eng., FEC.*"
Executive Vice-President and Director

SCHEDULE "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. 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;
4. 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 provide better communication between Directors and external auditors;
3. To enhance the external auditor's independence;
4. To increase the credibility and objectivity of financial reports; and
5. 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.

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 be "independent" (as such term is used in National Instrument 52-110 — *Audit Committees* ("**NI 52-110**") unless the Board determines that the exemption contained in NI 52-110 is available and determines to rely thereon.
2. The Board may from time to time designate one of the members of the Committee to be the Chair of the Committee.
3. All of the members of the Committee must be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon in accordance with the provisions of NI 52-110.

Mandate and Responsibilities of Committee

It is the responsibility of the Committee to:

1. Oversee the work of the external auditors, including the resolution of any disagreements between Management and the external auditors regarding financial reporting.

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 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. The process should include but not be limited to:

   - 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;
   - reviewing significant accruals, reserves or other estimates such as the ceiling test calculation;
   - reviewing accounting treatment of unusual or non-recurring transactions;
   - ascertaining compliance with covenants under loan agreements;
   - reviewing disclosure requirements for commitments and contingencies;
   - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;
   - reviewing unresolved differences between Management and the external auditors; and
   - obtain explanations of significant variances with comparative reporting periods.

4. Review the financial statements, prospectuses, MD&A, annual information forms ("**AIF**") 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 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.

5. With respect to the appointment of external auditors by the Board:

   - recommend to the Board the external auditors to be nominated;
   - recommend to the Board the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors will report directly to the Committee;
   - on an annual basis, review and discuss with the external auditors all significant relationships such auditors have with the Corporation to determine the auditors' independence;
   - 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; and
   - review and pre-approve any non-audit services 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 delegate to one or more independent members the authority to pre–approve non–audit services, provided that the member(s) report to the Committee at the next scheduled meeting such pre–approval and the member(s) comply with such other procedures as may be established by the Committee from time to time.

6. Review with external auditors (and internal auditor if one is appointed by Bellatrix) their assessment 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.

7. Review risk management policies and procedures of the Corporation (i.e., hedging, litigation and insurance).

8. Establish a procedure for:

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

   - the confidential, anonymous submission by employees of Bellatrix of concerns regarding questionable accounting or auditing matters.

9. Review and approve Bellatrix's hiring policies regarding partners and employees and former partners and employees of the present and former external auditors of the Corporation.

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 persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at such compensation as established by the Committee and at the expense of Bellatrix without any further approval of the Board.

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 four times per year. 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 will meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

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

7. 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.

8. 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.

9. 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.

10. 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.

11. 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.

November 1, 2009