CORRIDOR RESOURCES INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2014

March 30, 2015

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GLOSSARY

In this AIF, unless the context otherwise requires, the following words and phrases shall have the meanings set forth below:

"**ABCA**" means the *Business Corporations Act* (Alberta), as amended from time to time;

"**AIF**" means this Annual Information Form of Corridor dated March 30, 2015;

"**Anticosti General Partner**" means Anticosti Hydrocarbons General Partner Inc., a Québec corporation established by each of Corridor, Ressources Québec, Pétrolia and M&P pursuant to the Anticosti Joint Venture, which is the general partner of Anticosti Hydrocarbons;

"**Anticosti Hydrocarbons**" means Anticosti Hydrocarbons L.P., a Québec limited partnership established by each of Corridor, Ressources Québec, Pétrolia and M&P pursuant to the Anticosti Joint Venture;

"**Anticosti Joint Venture**" means the joint venture entered into on April 1, 2014 between Corridor, Ressources Québec, Pétrolia and M&P in respect of Corridor's and Pétrolia's interests in Anticosti Island, Québec;

"**Apache**" means Apache Canada Ltd.;

"**Apache Agreement**" means the farm-out and option agreement dated December 7, 2009 between Apache and Corridor to appraise and potentially develop oil and natural gas resources in southern New Brunswick;

"**API**" means the American Petroleum Institute;

"**BAPE**" means Québec's Bureau d'audiences publiques sur l'environnement;

"**Board of Directors**" refers to the board of directors of Corridor;

"**CEAA**" means the *Canadian Environmental Assessment Act*;

"**C-NLOPB**" means Canada – Newfoundland and Labrador Offshore Petroleum Board;

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook;

"**Common Share**" or "**Common Shares**" mean, respectively, one or more common shares in the capital of Corridor;

"**Corridor**" or "**Corporation**" means Corridor Resources Inc., a corporation incorporated under the ABCA;

"**developed non-producing reserves**" refers to 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;

"**developed producing reserves**" refers to 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;

"**developed reserves**" refers to 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;

"**discovered petroleum initially-in-place**", the equivalent of "**discovered resources**", refers to that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and contingent resources; the remainder is unrecoverable;

"**discovered unrecoverable petroleum initially-in-place**", the equivalent of "**discovered unrecoverable resources**", refers to that portion of discovered petroleum initially-in-place which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks;

"**EA**" refers to a project specific screening level environmental assessment;

"**GLJ**" refers to GLJ Petroleum Consultants Ltd., independent petroleum engineers of Calgary, Alberta;

"**GLJ Reserves Report**" means the report of GLJ dated and with a preparation date of February 18, 2015 and an effective date of December 31, 2014, setting forth certain information relating to certain natural gas, crude oil and natural gas liquids reserves of Corridor properties, specifically the McCully Field and the Caledonia Field, and the net present value of the estimated future net reserves associated with such reserves;

"**gross reserves**" refers to Corridor's working interest reserves before the deduction of royalties and before including any royalty interests;

"**gross wells**" refers to the total number of wells in which Corridor has an interest;

"**IFRS**" means International Financial Reporting Standards;

"**M&NP**" means the Maritimes & Northeast Pipeline;

"**M&P**" means Maurel & Prom S.A., inclusive of its subsidiary, Saint-Aubin E&P Québec Inc., and which is a participant in the Anticosti Joint Venture;

"**NEB**" means the National Energy Board;

"**net reserves**" refers to Corridor's working interest reserves after royalty deductions plus royalty interest reserves;

"**net wells**" refers to the aggregate of the numbers obtained by multiplying each gross well by Corridor's percentage working interest in that well;

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

"**PCS**" means Potash Corporation of Saskatchewan Inc.;

"**Pétrolia** " means Pétrolia Inc., and which is a participant in the Anticosti Joint Venture;

"**possible reserves**" refers to those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves;

"**probable reserves**" refers to 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;

"**prospective resources**" refers to those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development;

"**proved reserves**" refers to 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;

"**RA**" means the Responsible Authority under the CEAA;

"**reserves**" refers to the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, 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;

"**resources**" refers to a general term that may refer to all or a portion of total resources;

"**Ressources Québec**" means Ressources Québec Inc., a subsidiary of Investissement Québec, an affiliate of the Government of Québec, which is a participant in the Anticosti Joint Venture;

"**Ro**" refers to reflectance suppressed by high oil saturation;

"**Rock Eval**" refers to the method used to identify the type and maturity of organic matter and to detect petroleum potential in sediments;

"**royalties**" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula;

"**Schlumberger Canada**" means Schlumberger Canada Inc.;

"**SEA**" refers to the Western Newfoundland Strategic Environmental Assessment;

"**shut-in**" refers to wells that are capable of producing natural gas which are not producing due to lack of available transportation facilities, available markets or other reasons;

"**Sproule**" means Sproule Associates Limited, independent petroleum engineers of Calgary, Alberta;

"**Sproule Anticosti Resources Report**" means the Resource Assessment report of the Macasty Formation in Certain Petroleum and Natural Gas Holdings on Anticosti Island for Pétrolia Inc. and Corridor Resources Inc. prepared by Sproule dated July 12, 2011 with an effective date of June 1, 2011, setting forth certain information regarding total petroleum initially-in-place of the properties owned by the Anticosti Joint Venture in the Macasty shale formation on Anticosti Island;

"**TOC**" refers to total organic carbon;

"**total petroleum initially-in-place**" or "**PIIP**", the equivalent of "**total resources**", refers to that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered;

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

"**undeveloped reserves**" refers to 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, possible) to which they are assigned;

"**undiscovered petroleum initially-in-place**", the equivalent of "**undiscovered resources**", refers to that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially-in-place is referred to as prospective resources, the remainder as unrecoverable;

"**undiscovered unrecoverable petroleum initially-in-place**", the equivalent of "**undiscovered unrecoverable resources**", means that portion of undiscovered petroleum initially-in-place which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks;

"**unproved property**" means a property or part of a property to which no reserves have been specifically attributed; and

"**working interest**" means the percentage of undivided interest held by Corridor in an oil and natural gas property.

ABBREVIATIONS AND EQUIVALENCIES

The following are abbreviations and definitions of terms used in this AIF.

Crude Oil and Natural Gas Liquids		Natural Gas	
bbl	one barrel equaling 34.972 Imperial gallons or 42 U.S. gallons	btu	British Thermal Units
bblpd	barrels per day	mscf	thousand standard cubic feet
boe[(1)]	barrels of oil equivalent	mscfpd	thousand standard cubic feet per day
boepd	barrels of oil equivalent per day	mmbtu	million British Thermal Units
mboe	thousand barrels of oil equivalent	mmbtupd	million British Thermal Units per day
mbbl	thousand barrels	mmscf	million standard cubic feet
mmbbls	million barrels	mmscfpd	million standard cubic feet per day
bboe	billion barrels of oil equivalent	scf	standard cubic feet
mmboe	million barrels of oil equivalent	scfpd	standard cubic feet per day
NGL or NGLs	natural gas liquids, consisting of any one or more of propane, butane and condensate	bscf	billion standard cubic feet
		tscf	trillion standard cubic feet
WTI	West Texas Intermediate crude oil delivered at Cushing, Oklahoma	psi	pounds per square inch

Financial	
M$	thousands of dollars (Cdn.)
MM$	millions of dollars (Cdn.)

Note:

(1) All calculations converting natural gas to crude oil equivalent have been made using a ratio of six mscf of natural gas to one barrel of crude equivalent. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of six mscf of natural gas to one barrel of crude oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert From	To	Multiply By
mscf	cubic metres	28.317
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

Except as otherwise specified, all references to "dollars", or to "$" are to Canadian dollars.

FORWARD-LOOKING INFORMATION

This AIF contains certain forward-looking statements and forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "should", or similar words suggesting future outcomes. In particular, this AIF contains forward-looking statements pertaining to the following:

- business plans and strategies;
- the Anticosti Joint Venture and its plans;
- capital budget;
- cash flow from operations;
- capital expenditure programs;
- exploration and development plans, including plans to drill an offshore exploration well on the Old Harry prospect in the Gulf of St. Lawrence;
- the ability to find a joint venture partner for each of the Frederick Brook shale and the Old Harry prospect and to extend exploration license EL-1105;
- plans of the Anticosti Joint Venture to update resources reports;
- timing to secure regulatory approvals;
- government support of exploration and development activities;
- operating expenses;
- the quantity of natural gas, oil and natural gas liquids reserves and resources;
- net present values of future net revenues from reserves;
- development costs;
- estimates of production;
- estimates of tax pools;
- timing of taxation;
- abandonment and reclamation costs;
- projections of market prices and premiums;
- projections of costs;
- supply and demand for natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions, exploration and development;
- expectations relating to the renewal of licenses; and
- treatment under governmental regulatory regimes.

Statements relating to "reserves" and "resources" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described, as applicable, exist in the quantities predicted or estimated and can profitably be produced in the future.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Corporation and its shareholders.

Forward-looking statements are based on the Corporation's current beliefs as well as assumptions made by, and information currently available to, the Corporation concerning anticipated financial performance, business prospects, strategies, regulatory developments, future natural gas and oil commodity prices, exchange rates, future natural gas production levels, the ability to obtain equipment in a timely manner to carry out development activities, the ability to market natural gas successfully to current and new customers, the impact of increasing competition, the ability to obtain financing on acceptable terms, the ability to add production and reserves through development and exploration activities, and the terms of agreements with third parties such as the Corporation's forward sales contracts, transportation contracts and the Anticosti Joint Venture. Although management considers these assumptions to be reasonable based on information currently available to it, they may prove to be incorrect.

By their very nature, forward-looking statements involve inherent risks and uncertainties (both general and specific) and risks that forward-looking statements will not be achieved. These factors include, but are not limited to, risks associated with oil and gas exploration, substantial capital requirements and financing, volatility of natural gas and oil prices, government regulation, environmental, hydraulic fracturing, third party risk, dependence on key personnel, co-existence with mining operations, availability of drilling equipment and access, risks may not be insurable, variations in exchange rates, expiration of licenses and leases, reserves and resources estimates, development and/or acquisition of oil and natural gas properties, trading of common shares, seasonality, competition, management of growth, conflicts of interest, issuance of debt, title to properties and hedging. Further information regarding these factors may be found under the heading "*Risk Factors*" in this AIF, and in the Corporation's most recent financial statements, management's discussion and analysis, management information circular, material change reports and news releases. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive.

The forward-looking statements contained in this AIF are made as of the date hereof and the Corporation does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

CORPORATE STRUCTURE

Corridor Resources Inc. is the continuing corporation resulting from the amalgamation under the ABCA on May 13, 1996 of Corridor Resources Inc., a closely-held corporation, and Contwoyto Goldfields Limited, a corporation with minimal assets and liabilities and with a "reporting issuer" status in British Columbia, Alberta, Ontario, and Québec. On June 14, 2011, the articles of the Corporation were amended to increase the minimum and maximum number of directors of the Corporation to three directors and nine directors, respectively.

The Corporation has a 21.67% interest in Anticosti Hydrocarbons, see "*Description of the Properties - Anticosti Island, Québec – Anticosti Joint Venture*".

The Corporation does not have any subsidiaries.

The head office of Corridor is located at 301, 5475 Spring Garden Road, Halifax, Nova Scotia, B3J 3T2 and the registered office is located at 4500, 855 - 2nd Street, S.W., Calgary, Alberta, T2P 4K7.

GENERAL DEVELOPMENT OF THE BUSINESS

General

The Corporation is an Eastern Canadian junior resource company engaged in the exploration for and development and production of petroleum and natural gas onshore in New Brunswick and Québec and offshore in the Gulf of St. Lawrence. The Corporation currently has natural gas production and reserves in the McCully Field near Sussex, New Brunswick. In addition, the Corporation has discovered unrecoverable resources in Elgin, New Brunswick and a 21.67% interest in Anticosti Hydrocarbons, a joint venture which has undiscovered resources on Anticosti Island, Québec.

As at March 30, 2015, Corridor had 17 full time employees and 1 full time consultant.

Corridor's operations are currently focused on four principal properties, being: the McCully Field, New Brunswick; Anticosti Island, Québec (through its 21.67% interest in the Anticosti Joint Venture); the Elgin Sub-Basin, New Brunswick; and the Gulf of St. Lawrence.

McCully Field, New Brunswick

The Corporation drilled the natural gas discovery well at the McCully Field in September 2000. The well was drilled in partnership with PCS as a result of a farm-in which provided that PCS would pay 100% of the costs of the well to earn a 50% working interest in four sections (3,561 acres).

On June 28, 2007, the Corporation commenced the flow of natural gas from the McCully Field into the gas conditioning plant and 50 kilometre lateral pipeline to connect the McCully Field with the M&NP. Corridor continued to produce natural gas at the McCully Field following initial deliveries to M&NP with gross production averaging over 26.1 mmscfpd (19.5 mmscfpd net) in July 2007.

As at the date hereof, 39 wells have been drilled in the McCully Field, all of which have encountered natural gas. Gross production from the McCully Field was approximately 9.3 mmscfpd (7.2 mmscfpd net) in December 2014 and 9.3 mmscfpd (7.1 mmscfpd net) for the year ended December 31, 2014.

On October 28, 2014, Corridor announced the initial results of its 2014 well re-entry and fracturing program at the McCully Field and Elgin Field in southern New Brunswick. The program resulted in increased natural gas production and revenues from the McCully Field and demonstrated that the Frederick Brook shale is productive from at least six different sub-intervals across a distance of 25 kilometers. The program resulted in the fracture stimulation of two sand intervals in the Hiram Brook and three shale intervals in the Frederick Brook.

While the New Brunswick Government has reconfirmed its support of natural resources development, on March 27, 2015 it enacted *An Act to Amend the Oil and Natural Gas Act* which creates a moratorium on all forms of hydraulic fracturing in New Brunswick, regardless of whether the process uses water, propane or another substance to extract natural gas from shale rock beneath the earth's surface. The vast majority of wells drilled by Corridor and its partners in New Brunswick have been fracture stimulated by water as the stimulation fluid, with recent wells using liquefied propane, both of which are considered hydraulic fracture stimulators. While the moratorium is in effect, Corridor's ability to maintain or increase its natural gas production is significantly reduced. For more information, see "*Industry Conditions – Environmental Regulation – New Brunswick*" and "*Risk Factors - Hydraulic Fracturing*".

The applicable leases are detailed in the "*Description of the Properties – New Brunswick Lands – McCully Field*" and reserve and other information is set forth under "*Statement of Reserves and other Oil and Gas Information*".

Anticosti Island, Québec

On May 20, 2010, Corridor entered into a joint venture agreement with Pétrolia to conduct a four-well joint exploration drilling program on Anticosti Island.

In June 2011, Corridor and Pétrolia retained Sproule to estimate the quantity of hydrocarbon resource contained within the Macasty Formation shales on Anticosti Island, at which time Sproule categorized the resources as undiscovered petroleum initially-in-place. See "*Resources Information – Sproule Anticosti Resources Report"*.

On February 21, 2012, the Corporation announced results of a study by Schlumberger Canada, which suggests that the rock properties of the Macasty shale are similar to those of the Utica shale in Ohio, one of the most prolific shales in the United States.

In the fall of 2012, Corridor and Pétrolia conducted an exploration program on Anticosti Island to advance the understanding of the development potential of the vast shale oil prospect on Anticosti Island. In January 2013, Corridor announced the initial results of the Macasty core analyses from the Pétrolia/Corridor Princeton Lake and High Cliff wells drilled as part of such exploration program, which confirmed that the Macasty Formation is within the oil/condensate window at all locations. These results are very positive indicators for the hydrocarbon production potential of the Macasty Formation.

On April 1, 2014, Corridor announced the closing of the Anticosti Joint Venture with Ressources Québec, Pétrolia and M&P, which joint venture was formed to appraise and potentially develop hydrocarbon resources on Anticosti Island. The parties completed the formation of the Anticosti Joint Venture pursuant to which Corridor acquired a 21.67% interest in the Anticosti Joint Venture by transferring all of its right, title and interest in and to its Anticosti exploration licenses covering 891,906 acres, and redeeming certain limited partnership units in exchange for a cash payment from Anticosti Hydrocarbons to Corridor in the amount of $15.26 million. For additional information regarding the Anticosti Joint Venture, see "*Description of the Properties - Anticosti Island, Québec – Anticosti Joint Venture*".

As part of the first phase of the Anticosti Joint Venture's exploration program, five stratigraphic coreholes were drilled into the Macasty Formation in 2014. Corridor is encouraged with the initial results of the program, as the results of the core analysis and petrophysical log surveys generally meet or exceed the Corporation's expectations. The stratigraphic corehole program experienced start-up delays due to the adoption of a new regulatory framework and the program was temporarily suspended during the winter season. The Anticosti Joint Venture intends to resume the drilling of the remaining approved stratigraphic corehole wells in the spring of 2015, to complete this program during the year, and to drill the three horizontal wells in 2016. The results of all the cores will help assess the rock quality and determine the optimal location for the three test wells.

See *"Description of the Properties – Anticosti Island, Québec ".*

Elgin Sub-Basin, New Brunswick

In 2009, Corridor drilled and fracture stimulated with propane the Green Road G-41 (vertical) well and completed initial clean-up flow of two intervals in the upper part of the Frederick Brook formation. The first of the two fracs resulted in the placement of 46 tonnes of proppant in a black shale interval at a depth between 2000 and 2050 metres. The second frac resulted in the placement of 68 tonnes of proppant in a silty interval of the formation containing thin interbeds of sandstone at a depth between 1850 and 1900 metres. Following completion of the fracturing operations, commingled clean-up flow was conducted for the two intervals. At the end of a 57 hour flow period, the well was flowing at a restricted rate of 4.1 mmscfpd, consisting of approximately 85% natural gas and 15% propane frac fluid at a flowing wellhead pressure of 2083 psi. A temperature log confirmed that both intervals were contributing to the flow. These results represented the first significant flow of natural gas from the Frederick Brook formation. In December 2009, Corridor completed segregated testing of the two intervals. Following the initial commingled zone testing, a tubing string with a packer was installed in the well and the two zones were independently tested. The first test interval (a black shale at a depth interval between 2000 and 2050 metres) was flowing natural gas at a stabilized rate of 0.43 mmscfpd at the end of an 83 hour flow period at a final flowing wellhead pressure of 147 psi. The second test interval (a silty, sandy shale at a depth interval between 1850 and 1900 metres) produced a total of 42.4 mmscf of natural gas over a 185 hour flow period at a peak rate of 11.7 mmscfpd and a final stabilized rate of 3.0 mmscfpd at a final flowing wellhead pressure of 699 psi.

On May 31, 2011, Apache advised the Corporation that it had elected not to proceed with the second phase of the farm-out program with Corridor in respect of the potential shale gas resource development near Elgin, New Brunswick in accordance with the Apache Agreement. Apache had drilled two horizontal wells (Will DeMille G-59 and Green Road B-41) and hydraulically fracture stimulated these wells pursuant to the Apache Agreement, using similar large slick water techniques, but as at May 31, 2011 the wells had not generated sustained shale gas production. In May 2011, the Will DeMille G-59 well was re-opened and flowed frac fluid at low rates with minor gas shows over five days. It is important to note that, when the Will DeMille G-59 well was shut-in after initial testing in early December, 2010, it had recovered only approximately 4% of the total frac fluid. The Green Road B-41 well had been placed on a 45 day gas lift which ended on March 16, 2011. At that time, the well was shut-in after recovering 17% of the frac fluid. In late May 2011, due to significant well head pressure build-up, the well was reopened and flowed gas at a maximum rate of 0.7 mmscfpd for several hours prior to frac fluids loading the well causing gas rates to decline. Based on a consensus among third party expert consultants and Corridor technical staff, the most significant issues identified with the G-59 and B-41 well performance relate to the design of the horizontal wells in this high-stress environment and the fracture technique. Corridor believes that a different well design and frac program could lead to a commercial development of the Frederick Brook shale. It should also be noted that Corridor re-tested the Green Road G-41 well in December 2010, which produced gas at a constant rate of four mmscfpd for five days at a final flowing pressure of 1306 psi. During the first quarter of 2011, the G-41 well was used to provide gas lift for the Green Road B-41 well and consistently delivered the required rate of 0.5 mmscfpd during a 45 day test, at a final pressure of 2007 psi.

As part of the termination of the Apache agreement, Apache conveyed to Corridor the interest earned in the spacing units in the two horizontal wells drilled in the Elgin area and abandoned the Will DeMille G-59 well, and Corridor assumed the abandonment and reclamation obligation for the Green Road B-41 well.

On November 14, 2011, Corridor completed the drilling of the vertical Will DeMille O-59 shale gas appraisal well to a total depth of 3188 meters measured depth. Strong gas shows were encountered within Hiram Brook sandstones and the Upper Frederick Brook shale. Based upon initial analysis of well log information, the well intersected at least eight intervals with significantly elevated gas shows that are considered fracture candidates.

In 2012, Corridor retested the Green Road B-41 well, previously drilled by Apache pursuant to the Apache Agreement, and was successful at removing a tool stuck in this well in 2011. While the well did not flow material amounts of gas, a section of the horizontal leg of this well was made available for future fracturing operations.

On October 28, 2014, Corridor announced the initial results of its 2014 well re-entry and fracturing program at the McCully Field and Elgin Field in southern New Brunswick. The program resulted in the fracture stimulation of three intervals in the Frederick Brook shale and the results have demonstrated that the Frederick Brook shale is productive from at least six different sub-intervals across a distance of 25 kilometers. The focus of the 2014 program was to utilize existing wellbores that provided the most readily available access to stimulate and produce the Frederick Brook shale and not necessarily the most prospective intervals. Corridor has one long term producing well from the Frederick Brook shale; the F-58 well in the McCully Field which was fracture stimulated with water in a single 11 tonne treatment and placed on production in 2008. It is still producing at an estimated average rate of 180 mscf/d with a 1.8% annual decline. The Corporation expects F-58 to recover a total of 1.5 bscf (proved plus probable estimate as forecast by GLJ in its report effective December 31, 2014). Corridor recently placed on production three wells fracture stimulated in the Frederick Brook shale. Two of the wells have proven productive capacity as they continue to clean up drilling/workover fluids. The third well is following the production profile of the F-58 well.

While the New Brunswick Government has reconfirmed its support of natural resources development, on March 27, 2015 it enacted *An Act to Amend the Oil and Natural Gas Act* which creates a moratorium on all forms of hydraulic fracturing in New Brunswick, regardless of whether the process uses water, propane or another substance to extract natural gas from shale rock beneath the earth's surface. The vast majority of wells drilled by Corridor and its partners in New Brunswick have been fracture stimulated by water as the stimulation fluid, with recent wells using liquefied propane, both of which are considered hydraulic fracture stimulators. While the moratorium is in effect, Corridor's ability to attract a joint venture partner to participate in the exploration of the Frederick Brook shale is significantly reduced. For more information, see "*Industry Conditions – Environmental Regulation – New Brunswick*" and "*Risk Factors* **-** *Hydraulic Fracturing*".

The applicable leases are detailed in the "*Description of the Properties – New Brunswick Lands – Elgin Sub-Basin*". See also "*Resources Information – GLJ Shale Resources Report*".

Gulf of St. Lawrence

In October 2010, Corridor completed a geohazard survey to identify potential seabed hazards to drilling with the goal to ensure that any future exploration by Corridor on the Old Harry prospect is conducted in a safe and responsible manner.

On February 22, 2011, Corridor submitted a Project Description to the C-NLOPB for the drilling of an exploration well on the Old Harry prospect. Submission of the Project Description commenced the official regulatory process for obtaining the necessary approvals to drill the offshore well. Corridor submitted its completed EA in December 2011 and received regulatory comments from the C-NLOPB review of the document in April 2012. Corridor submitted a revised EA document addressing the regulatory comments in February 2013. An exploration well is an essential step in the evaluation of the Old Harry prospect, which offers significant hydrocarbon potential and associated benefits for Eastern Canada.

On July 16, 2012, the Minister of Environment designated Corridor’s Old Harry EA as a designated project under the *Canadian Environmental Assessment Act* ("**CEAA**") and, as a result, the screening for the project must be continued and completed under the CEAA.

On February 28, 2013, further to the update of the 2005 Strategic Environmental Assessment and 2007 Amendment for the Western Newfoundland and Labrador Offshore Area strategic environmental assessment, the C-NLOPB announced it would be preparing a draft SEA update to be released for public review in the second quarter of 2013. The C-NLOPB stated that it feels that there is value in having an updated SEA for the Western Newfoundland Offshore Area prior to the completion and public review of Corridor's Old Harry EA and that the results of the SEA update may contribute to a more informed project-specific EA. Once the updated SEA is completed, the C-NLOPB has advised that it will evaluate all options for public review of Corridor's Old Harry EA, including the possible resumption of an independent review. The C-NLOPB has advised that it is committed to ensuring the public have ample opportunity to express their concerns about the potential environmental impacts of offshore oil and gas activity in the Gulf of St. Lawrence.

On July 22, 2013, the C-NLOPB amended Corridor's Exploration Licence 1105 to extend Period 1 of the license from seven to eight years (January 15, 2016). Corridor’s exploration license also has a provision whereby Corridor can extend this drilling period by an additional year (January 13, 2017) with the payment of a $1 million deposit.

On May 5, 2014, the C-NLOPB issued the SEA update for the Western Newfoundland and Labrador offshore area. This report states that "petroleum exploration activity generally can proceed in the Western Newfoundland and Labrador offshore area with the application of standard mitigation measures currently applied." The C-NLOPB also indicated that additional consultations on Corridor's Old Harry EA are required in order for the C-NLOPB to finalize the Old Harry EA.

Corridor is in discussions with the C-NLOPB regarding the extension of its exploration license EL-1105 to complete its consultations on the Old Harry EA. Corridor expects to conclude these discussions in 2015.

The applicable leases are detailed in the "*Description of the Properties – Gulf of St. Lawrence – Newfoundland and Labrador and Québec*".

Other Prospects

The Corporation holds exploration licenses and leases for the following other prospects in eastern Canada a 100% working interest in ONG Lease 06-01 (40,930 acres) and a 50% working interest in ONG Lease 09-01 where one oil well has been drilled in the Caledonia Field(36,531 gross acres and 18,265 net acres).

Recent Developments

On March 27, 2015, *An Act to Amend the Oil and Natural Gas Act* was enacted which creates a moratorium on all forms of hydraulic fracturing in New Brunswick.

On March 24, 2015, the New Brunswick Government announced the appointment of a panel with a mandate to review and report on, within 12 months, whether the five conditions necessary to lift the New Brunswick moratorium can be met.

On March 19, 2015, Anticosti Hydrocarbons announced an update on its 2014 stratigraphic corehole program. The results from the five coreholes obtained in the eastern and central part of the Island were analyzed and met or exceeded the expectations of the partners. The results were determined to be within the range of the assumptions used in the Sproule Anticosti Resources Report. Anticosti Hydrocarbons intends to resume the drilling of the remaining approved stratigraphic corehole wells in the spring of 2015, to complete this program during the year and to drill three horizontal wells in 2016.

On March 2, 2015, Corridor entered into a forward sale agreement for the period from November 1, 2015 to March 31, 2016 for 2,500 mmbtu per day of natural gas (approximately 2.3 mmscf per day) at an average price of $US9.25/mmbtu.

Three Year History

The following is a summary of significant events in the development of the Corporation's business over the past three years.

Financial Year Ended December 31, 2014

McCully Field, New Brunswick

On February 3, 2014, Corridor announced that it had entered into a forward sale agreement for the period from November 1, 2014 to March 31, 2015 for an average of 4,000 mmbtu per day of natural gas (approximately 3.8 mmscf per day) at an average price of $US11.74/mmbtu. This agreement resulted in a netback of approximately $CAD10/mscf for approximately 50% of Corridor's production for that period. Corridor also entered into forward sale agreements in 2014 for the sale of 2,258 mmbtupd from March 1, 2014 to March 31, 2014 at an average price of $US10.76/mmbtu and the sale of 3,000 mmbtupd from April 1, 2014 to April 30, 2014 at an average price of $US7.25/mmbtu. The forward sale agreements covered approximately two-thirds (including a forward sale agreement entered into in 2013) of Corridor's estimated production for March 2014 and one-third for April 2014.

On October 28, 2014, Corridor announced the initial results of its 2014 well re-entry and fracturing program at the McCully Field and Elgin Field in southern New Brunswick. The program resulted in increased natural gas production and revenues from the McCully Field and demonstrated that Frederick Brook shale is productive from at least six different sub-intervals across a distance of 25 kilometer. The program, at a cost of $22.5 million, resulted in the fracture stimulation of two sand intervals in the Hiram Brook and three shale intervals in the Frederick Brook.

On December 23, 2014, Corridor announced that it had entered into a forward sale agreement for the period from January 1, 2015 to March 31, 2015 for an average of 1,344 mmbtu per day of natural gas (approximately 1.3 mmscf per day) at an average price of $US11.50/mmbtu. This sale, in combination with the forward sale announced on February 3, 2014 for 4,000 mmbtu per day from November 1, 2014 to March 31, 2015, resulted in an average hedged price of $US11.68/mmbtu for an average of 5,344 mmbtu per day (approximately 5mmcf per day) for the first quarter of 2015, see "*Other Oil and Gas Information – Forward Contracts*".

Anticosti Island, Québec – Anticosti Joint Venture

On April 1, 2014, Corridor announced the closing of the Anticosti Joint Venture with Ressources Québec, Pétrolia and M&P, which joint venture was formed to appraise and potentially develop hydrocarbon resources on Anticosti Island. The parties completed the formation of the Anticosti Joint Venture by, among other things (including entering into the securityholders agreement and the limited partnership agreement), (i) subscribing for shares of Anticosti General Partner; and (ii) subscribing for units of Anticosti Hydrocarbons, a newly formed Québec limited partnership with Anticosti General Partner acting as general partner, pursuant to which Corridor acquired a 21.67% interest in the Anticosti Joint Venture by transferring all of its right, title and interest in and to its Anticosti exploration licenses covering 891,906 acres, and redeeming certain limited partnership units in exchange for a cash payment from Anticosti Hydrocarbons to Corridor in the amount of $15.26 million. For additional information regarding the Anticosti Joint Venture, see "*Description of the Properties - Anticosti Island, Québec – Anticosti Joint Venture*".

On November 3, 2014, Corridor announced that, as part of the first phase of the Anticosti Joint Venture's exploration program four stratigraphic corehole wells were drilled into the Macasty Formation and an additional corehole would be completed in the next few weeks. Corridor was encouraged with the program, as the core obtained from these wells had positive indications of the presence of hydrocarbons. Corridor announced that the stratigraphic corehole program experienced start-up delays due to the adoption of a new regulatory framework and that the program would be temporarily suspended during the winter season and scheduled to resume in the spring of 2015. At the time, Corridor expected that the remainder of the stratigraphic corehole program would be completed by the summer of 2015. The results of all the cores will help assess the rock quality and determine the optimal location for three test wells. Anticosti Hydrocarbons intends to drill and fracture stimulate three test wells as soon as possible thereafter.

As a condition of the development of any oil and gas resources in Québec, the Québec Government has mandated a comprehensive strategic environmental assessment (the "**Québec SEA**") process in respect of the entire oil and gas sector in Québec, which shall include a specific individual assessment of Anticosti Island (the "**Anticosti SEA**"). The Québec SEA in respect of Anticosti Island is being carried out in tandem with the exploration work of the Anticosti Joint Venture. The Québec SEA will help assess the likely consequences of oil and gas development and estimate the economic effects of development of the oil and gas sector in Québec. Through the Québec SEA, the Québec Government intends to undertake a comprehensive review and modernization of legislation and the regulatory framework governing oil and gas exploration and development. The Anticosti SEA will study the social and economic impacts of oil and gas development on the island and identify best practices and technologies for development, as well identify methods to foster local economic spinoffs.

Only after the completion of both the Québec SEA and the Anticosti SEA will the potential of such resources be assessed and potentially developed. For more information, see "*Industry Conditions – Environmental Regulation – Québec*" and "*Risk Factors - Hydraulic Fracturing*".

For additional information regarding the Anticosti Joint Venture, see "*Description of the Properties - Anticosti Island, Québec – Anticosti Joint Venture*".

Gulf of St. Lawrence

On May 5, 2014, the C-NLOPB issued the SEA update for the Western Newfoundland and Labrador offshore area. This report states that "petroleum exploration activity generally can proceed in the Western Newfoundland and Labrador offshore area with the application of standard mitigation measures currently applied." The C-NLOPB also indicated that additional consultations on Corridor's Old Harry EA are required in order for the C-NLOPB to finalize the Old Harry EA.

Other

On March 6, 2014, Corridor announced that it had authorized a $27.2 million capital expenditure program for 2014 primarily related to a well re-entry and fracturing program in the McCully Field located in southern New Brunswick. The program was designed to increase natural gas production and revenues from the McCully Field and to evaluate the oil and shale gas potential of the Frederick Brook shale in the surrounding basin, while maintaining a strong balance sheet with no outstanding debt.

Effective April 1, 2014, the Government of New Brunswick implemented a new two-tier royalty regime for natural gas production. The new regime changes the basic royalty rate payable from the previous 10% to a royalty rate equal to the greater of a 4% basic royalty calculated on the wellhead revenues and a 2% minimum royalty calculated on gross revenues. After the Corporation has recovered all costs and begins to make a profit, the royalty rate will increase to 25%.

In July 2014, Corridor renewed its credit facility with a Canadian Chartered bank. As at the date hereof, Corridor has a $6 million revolving short term credit facility that matures on July 25, 2015.

On August 1, 2014, Mr. Phil Knoll, President and CEO, announced his planned retirement. After an extensive search, Mr. Steve Moran was appointed President and CEO of Corridor on September 29, 2014.

The Government of New Brunswick has advised, most recently on December 18, 2014, that it is committed to the development of its natural resources. However, on March 27, 2015, the New Brunswick Government enacted *An Act to Amend the Oil and Natural Gas Act* that allows government to prohibit hydraulic fracturing activity. Energy and Mines Minister Donald Arseneault stated that the moratorium will not be lifted until the following conditions are satisfied: (i) a social license for hydraulic fracturing is established; (ii) there is clear and credible information about the impacts of hydraulic fracturing on health, environment and water, so that a regulatory regime may be developed; (iii) a plan is established that mitigates the impacts on New Brunswick's public infrastructure and that addresses issues such as waste water disposal; (iv) a process is in place to respect New Brunswick's obligations under the duty to consult with First Nations; and (v) a proper royalty structure is developed to ensure that the benefits of fracturing are maximized for residents of New Brunswick. In furtherance of this, on March 24, 2015, the New Brunswick Government announced the appointment of a panel with a mandate to review and report on, within 12 months, whether the five conditions necessary to lift the New Brunswick moratorium can be met. The moratorium applies to all forms of hydraulic fracturing in New Brunswick, regardless of whether the process uses water, propane or another substance to extract natural gas from shale rock beneath the earth's surface. See "*Industry Conditions – Environmental Regulation – New Brunswick*" and "*Risk Factors - Hydraulic Fracturing*".

On December 16, 2014, Québec Premier Philippe Couillard announced that, while developing shale gas would bring economic and financial benefit, there is not sufficient support from the population to move forward with such development. Premier Couillard subsequently clarified that he "wants the doors to stay open … or at least, that people know how to open the door" for investment in the development of Québec's oil and gas resources.

While it is not possible to predict the final outcome of the ongoing or proposed studies, policies, legislation or regulation, any restrictions will increase the costs as well as delay or halt Corridor's ability to develop its oil and gas resources in New Brunswick (McCully Field, Caledonia Field and the Elgin Sub-Basin) and will affect the Anticosti Joint Venture's ability to develop its resources in Québec (Anticosti Island).

Financial Year Ended December 31, 2013

McCully Field, New Brunswick

On August 1, 2013, Corridor began to sell its natural gas production from the McCully Field using the Algonquin city-gate pricing point instead of the Dracut pricing point, as the Dracut sales hub was no longer actively traded. Corridor's expectation was that natural gas prices, net of the additional transportation charge, would be representative of New England market prices.

On October 22, 2013, Corridor announced that it had entered into a forward sale agreement from November 1, 2013 to March 31, 2014 for an average of 3,000 mmbtu per day (approximately 2.8 mmscf per day), at an average price of $US9.03/mmbtu and an estimated netback of approximately $6.50/mscf. This forward sale agreement represented approximately one-third of Corridor's estimated production for that period.

On December 6, 2013, Corridor announced that it had entered into a forward sale agreement for the period January 1, 2014 to February 28, 2014 for an average of 2,370 mmbtu per day of natural gas production (approximately 2.2 mmscf per day). This sale was at an average price of $US15.50/mmbtu, resulting in a netback of approximately $CAD12.50/mscf. Corridor's remaining production was sold at daily market prices which were strong during this period due to the high basis differential in the New England market.

Anticosti Island, Québec

In January 2013, Corridor announced the initial results of the Macasty core analyses from the Pétrolia/Corridor Princeton Lake and High Cliff wells that were drilled in the fall of 2012 on Anticosti Island. The Princeton Lake and High Cliff wells intersected 90 meters and 57 meters of highly organic Macasty Formation, respectively. The cores were sampled at 50 cm intervals and analyzed by Weatherford (Princeton Lake) and TerraTek Labs (High Cliff). The results provided an average of 4.0% TOC in both wells. It is important to note that TOC averaged 5.5% through a 10 meter section at the High Cliff well, with the highest TOC measured at 7.1%. At the Princeton Lake well, TOC averaged 6.0% through a 10 meter section, with the highest TOC measured at 7.5%. The results include hydrocarbon saturation levels as measured by the S1 (free hydrocarbons within pore spaces) at an average of 5.7 mg/g at Princeton Lake and 4.6 mg/g at High Cliff through the 10 meter sections. The final corehole drilled was at Oil River. It intersected 30 meters of organic Macasty Formation and averaged approximately 4% TOC. The analyses confirmed that the Macasty Formation is within the oil/condensate window at all locations. These results are very positive indicators for the hydrocarbon production potential of the Macasty Formation.

Gulf of St. Lawrence

On July 22, 2013, the C-NLOPB amended Corridor's Exploration Licence 1105 to extend Period 1 of the license from seven to eight years (January 15, 2016). Corridor's exploration license also has a provision whereby Corridor can extend this drilling period by an additional year (January 13, 2017) with the payment of a $1 million deposit. At that time, Corridor believed that the extension would provide it with sufficient time to gain the regulatory permits required to drill the Old Harry prospect in a two year drilling window between 2015 and 2016**,** provided Corridor obtained a joint venture partner to participate in this exploration well. Corridor expected the C-NLOPB would be releasing its SEA update, which is a component of the C-NLOPB's review of the Old Harry EA, in April 2014.

Other

In August, 2013, Corridor renewed its credit facility with a Canadian Chartered bank.

On February 15, 2013, the New Brunswick Government released rules, "*Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick*", to support New Brunswick's on-going management of oil and gas activities and to ensure that New Brunswick continues to have the tools needed to guide oil and gas exploration and extraction in an environmentally responsible manner. For further information, see "*Industry Conditions – Environmental Regulation – New Brunswick*", "*Risk Factors – Hydraulic Fracturing*" and "*Industry Conditions – Royalties – New Brunswick*". At this time, the Province of New Brunswick also released for public comment a discussion document, "*Responsible Environmental Management of Oil and Gas Activities in New Brunswick: Sharing of Royalty Revenues From Natural Gas Activities in New Brunswick"*, which proposed a new royalty regime in New Brunswick.

On November 4, 2013, the Government of New Brunswick introduced a new two-tier royalty regime for natural gas production, designed to promote natural gas exploration. Operators must pay the greater of a 4% basic royalty based on wellhead revenues and a 2% minimum royalty calculated on gross revenues. After the operator recovers all costs and begins to make a profit, the royalty rate increases to 25%. At the time, it was expected that the new royalty regime would be effective April 1, 2014. See "*Industry Conditions – Royalties – New Brunswick*"

On February 6, 2013, the Québec Government announced that it would table legislation to ban the award of exploration licences and suspend those already granted on shale gas development on an indefinite basis. However, as of the date hereof, no such legislation has been enacted.

Financial Year Ended December 31, 2012

McCully Field, New Brunswick

In December 2012, Corridor entered into a forward sale agreement for 6,000 mmbtu per day effective from January 1, 2013 to March 31, 2013, which production represented approximately two-thirds of Corridor's estimated production for this period, at an average price of $US8.52/mmbtu.

Following a drop in natural gas prices at Henry Hub below US$2.00/mmbtu in the second quarter of 2012, Corridor shut-in four McCully Field wells from May until early November 2012, which resulted in a gross average lost daily production of approximately one mmscfpd during this period. Corridor resumed production of the shut-in wells early in November 2012 when natural gas prices increased due to cold weather.

Anticosti Island, Québec

In the fall of 2012, Corridor and Pétrolia conducted an exploration program on Anticosti Island to advance the understanding of the development potential of the vast shale oil prospect on Anticosti Island. The exploration program consisted of three components, including: (i) drilling three stratigraphic coreholes through the Macasty Formation at strategic locations across the Island; (ii) an extensive well core and cuttings sampling and analysis project that included 15 previously drilled Anticosti wells to map the organic content and maturity of the shale; and (iii) a baseline study of the Anticosti groundwater system that consisted of drilling and monitoring approximately 14 water wells (13 water wells actually drilled) as well as conducting a number of surface water studies. The objective of the program was to further define the resource estimates across Anticosti Island and to help select optimal locations where the next stage of drilling and testing programs could be initiated, leading toward potential development of this shale oil play.

Following the first component of the program, complete cores of the Macasty shale were preserved and sent to a laboratory specializing in assessing shales. Various tests and analyses were conducted to assist in confirming the quality of the shale. The results of these analyses were intended to provide information on rock parameters such as porosity, permeability, mineralogy and brittleness. A key objective of the coreholes was to test the Macasty intervals thickness on Anticosti Island as well as maturities and organic carbon content.

The extensive well core and cuttings sampling and analyses project in the second component of the program supplemented the existing core and cuttings analyses previously obtained on Anticosti

Island. In addition, three wells were sampled in the laterally equivalent Utica Formation of Ohio where a number of very interesting Initial Production (IP) rates had been recently announced. A Utica well from the St. Lawrence Lowlands was also sampled. A total of 556 samples were collected for Rock Eval (including TOC) analysis and 198 samples were collected for reflectance analysis (determining maturity through organic reflectivity or Ro). This new data, in combination with the existing data, was expected to refine Corridor's understanding of the maturation and TOC (quality) trends on Anticosti Island and help focus our exploration strategy.

Thirteen water wells were drilled during the third component of the program in 2012 for the purposes of groundwater monitoring. A number of surface water studies were conducted as well.

Elgin Sub-Basin, New Brunswick

In the fall of 2012, the New Brunswick Government amended the *Oil and Natural Gas Act* and the *Licence to Search and Lease Regulation* to allow lessees to consolidate two or more leases into a single contiguous lease. A consolidated lease will have prescribed annual work commitments on a per hectare basis and will be subject to penalties if the annual work commitment is not fulfilled. The lease consolidation mechanism was consistent with Corridor's plan for shale gas development in the Elgin Sub-basin, and the Corporation began this consolidation process in 2013.

In 2012, Corridor retested the Green Road B-41 well, previously drilled by Apache pursuant to the Apache Agreement, and was successful at removing a tool stuck in this well in 2011. While the well did not flow material amounts of gas, a section of the horizontal leg of this well was made available for future fracturing operations. Based on a consensus among third party expert consultants and Corridor's technical staff, the most significant issues previously identified with the B-41 well performance related to the design of the horizontal well in this high-stress environment and the fracture technique used. Corridor believes that a different well design and fracture program could lead to a commercial development of the Frederick Brook shale.

Gulf of St. Lawrence

On February 27, 2012, the C-NLOPB issued a decision to dismiss Corridor's application for a prohibition order in respect of Corridor's exploration license EL 1105. The application was made by Corridor as a result of what Corridor considered to be duplicative regulatory processes, due to Corridor being subject to a project specific EA (in respect of old Harry) while a concurrent SEA took place. If granted, the prohibition order would have effectively provided Corridor a "time-out" on its license during the conduct of the SEA. The C-NLOPB also decided on February 27, 2012 that the SEA update should be completed before proceeding with the review of the Old Harry EA for the single exploration well proposed to be drilled within Corridor's EL 1105. The C-NLOPB announced that the SEA update would be completed in early 2013.

On July 16, 2012, the Minister of Environment designated Corridor's Old Harry EA as a designated project under the CEAA and, as a result, the screening for the project must be continued and completed under the CEAA. The C-NLOPB, as the RA, was required to take a course of action no later than 365 days after the day on which CEAA 2012 came into force (July 6, 2012). It should be noted that the time taken by the proponent to comply with a request made by an RA is not included in the calculation of time.

Corridor had estimated that the Old Harry EA would take until late 2013 to be fully processed based on the expected completion date of the updated SEA and other regulatory requirements. Corridor then had until January 15, 2016 (with the payment of a deposit) to spud an exploration well at Old Harry.

Corridor released a request for proposal for the provision of drilling management services and also identified a drilling asset which would be available to undertake the Old Harry exploration program within the mid-2014 to January 2016 window.

Other

In July 2012, Corridor renewed its $6 million revolving short term credit facility with a Canadian Chartered bank.

On March 27, 2012, the Government of New Brunswick announced its 2012-2013 Budget in which it reaffirmed its commitment to exploring the development of a shale gas industry. The budget speech declared that New Brunswick must provide an environment that encourages exploration, development and added value.

On May 17, 2012, the Province of New Brunswick released for public comment *Responsible Environmental Management of Oil and Gas Activities in New Brunswick - Recommendations for Public Discussion* for new proposed environmental requirements which allow for the exploration and development of oil and gas in New Brunswick.

On March 20, 2012, the Québec Government announced its 2012-2013 Budget, which included provisions that recognize the potential of Québec as an oil and gas producer and outlined steps to encourage the development of this potential. The Government noted that it may determine whether it would be necessary to implement a royalty incentive for Anticosti Island. On November 20, 2012, the Québec Government stated in the 2013-2014 budget speech that it intended to develop Québec's oil potential and that it would consult the industry and the stakeholders concerned about natural resources development before making changes to the regimes that establish the framework for developing these non-renewable resources.

Mr. Jack Bray resigned as a director of the Corporation on January 20, 2012. Mr. Bray advised the Corporation that he was of retirement age and was cutting back on business commitments in several areas.

TRENDS

See "*Industry Conditions*" for characteristics of the oil and gas industry in which the Corporation participates.

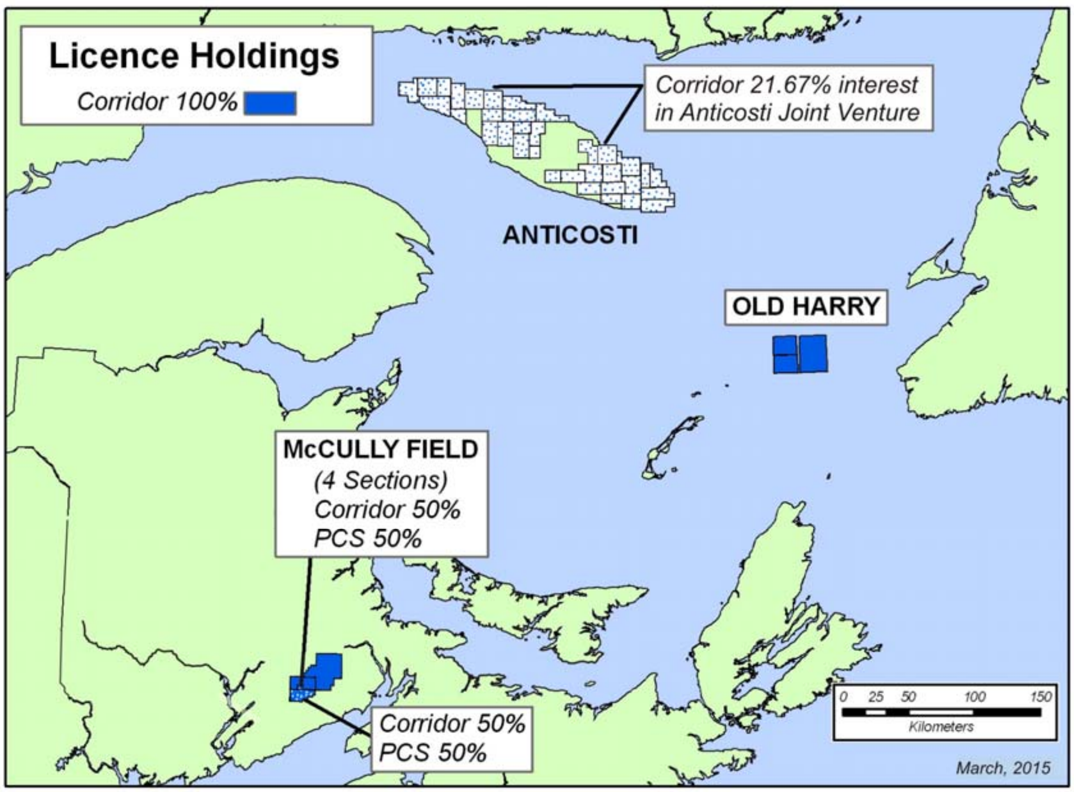
There are a number of trends that appear to be developing, which may have both long and short-term effects on the industry and the competitive positioning of the Corporation, and include the volatility of commodity prices and also increased environmental regulation, including restrictions and moratoriums on hydraulic fracturing in certain jurisdictions (including New Brunswick and Québec). The pricing trends are described briefly below and the environmental regulation trends are described in detail in "*Industry Conditions*" and also "*Risk Factors*". The discussion of these trends and their potential impact constitute forward-looking statements. Refer to "*Forward-Looking Statements*".

With regard to volatility of commodity prices, the market is experiencing a great deal of elasticity in pricing due to changes in domestic and international supply and demand for natural gas and oil, drilling activity, storage levels, fuel switching, market uncertainty and a variety of additional factors beyond the Corporation's control. Weather is another key factor in determining gas demand, making future gas prices highly unpredictable. Volatility in gas prices has a significant impact on the Corporation's revenues as all of the Corporation's production is natural gas. In addition, the fluctuation of the Canadian dollar relative to its U.S. counterpart affects the cash flow available to Canadian oil and gas producers to fund capital expenditures.

Corridor's natural gas production in the McCully Field in New Brunswick (Corridor's only producing field) is connected to the M&NP that supplies customers in the New England market in the United States. The New England market is, and is expected to continue to be, characterized by excess demand during the winter season. As a result of this recent excess demand, Corridor has been able to secure elevated premiums for its natural gas in 2013 and 2014. The premium to Henry Hub realized averaged US$3.74/mmbtu for the year ended December 31, 2014 compared to $US3.19/mmbtu for the year ended December 31, 2013 and US$1.10/mmbtu for the year ended December 31, 2012.

DESCRIPTION OF THE PROPERTIES

The following is a description of the Corporation's principal oil and natural gas properties. Unless otherwise specified, gross and net acres and well count information is at March 30, 2015.



New Brunswick Lands

Corridor’s ability to access premium markets from its existing production at the McCully Field and the Frederick Brook shale gas play in New Brunswick creates a strategic advantage for Corridor’s on-going natural gas development in New Brunswick.

McCully Field

The Corporation owns various working interests in the McCully Field, located approximately 12 kilometres northeast of Sussex, New Brunswick.

The Corporation's interests in the McCully Field consist of three petroleum and natural gas leases:

- 100% working interest in ONG Lease 06-01 (40,930 acres). At the date hereof, seventeen wells (D-48, H-28, B-58, F-58, E-38, J-38, J-76, H-76, P-76, K-48, J-47, C-48, I-47, C-29, P-47, L-38 and L-37) are located on these lands.
- 50% working interest in ONG Lease 06-02 (3,561 gross acres and 1,780 net acres). At the date hereof, twenty wells (A-67, P-56, P-66, K-57, C-67,G-67ST, O-66, D-57, J-67, K-66, M-66, J-66, E-57, I-67, D-66, D-67, E-67, C-57, P-67 and N-66) are located on these lands in which Corridor and PCS each hold a 50% working interest.
- 50% working interest in ONG Lease 09-01 (36,531 gross acres and 18,265 net acres held jointly with PCS) where wells J-65 and C-75 are located, subject to a 15% working interest held by EOG Resources in a ¼ section where well C-75 is located.

For additional information regarding the McCully Field, see "*General Development of the Business – Three Year History*".

The natural gas reserves and other gas information associated with the McCully Field are set forth in the GLJ Reserves Report, which is summarized under "*Statement of Reserves Data and Other Oil and Gas Information*".

Corridor and PCS Arrangements

The production, transportation, processing and marketing of natural gas from PCS' share of the production from the McCully Field are subject to agreements with PCS for use at the PCS potash mill, located near Sussex, New Brunswick and for processing at Corridor's midstream facilities. PCS' share of the natural gas is either taken in kind and delivered to the PCS potash mill or flows through Corridor's midstream facilities.

Caledonia Field

The Corporation's interests in the Caledonia Field consist of two petroleum and natural gas leases:

- 100% working interest in ONG Lease 06-01. One oil well has been drilled in the Caledonia Field (South Branch G-36 well).
- 50% working interest in ONG Lease 09-01.

On December 3, 2008, Corridor announced a potentially significant oil discovery at the South Branch G-36 well, located three kilometres southeast of the McCully Field in the southern flank of the Elgin Sub-Basin. The well was cased and two fracture stimulation treatments were carried out over two intervals within the Hiram Brook formation. At the end of 10 days of flowback and clean-up of frac fluids, the well was flowing, through production tubing, clean, 45º API oil and no water, at a measured rate of 59 bblpd. The well was shut-in awaiting installation of a pump to reduce down-hole pressure and increase the rate of production prior to undertaking long-term testing to evaluate the economic potential of the well. Corridor subsequently investigated several techniques to stimulate flow in the G-36 well, with limited results, including downhole treatments designed to reduce the high wax content of the oil and steam assisted flow techniques. In 2013, the Corporation entered into a paraffin research collaboration program with the University of New Brunswick. The results of the research in 2014 identified a wax remediation treatment that was up to 80% effective in suppressing paraffin deposition during oil flow in the laboratory. Given these results, Corridor is considering its options with respect to the G-36 well in the context of the current oil price environment.

For additional information regarding development activities in the Caledonia Field, see "*General Development of the Business – Three Year History*".

The crude oil reserves and other oil and gas information associated with the Caledonia Field are set forth in the GLJ Reserves Report, which is summarized under "*Statement of Reserves Data and Other Oil and Gas Information*".

Elgin Sub-Basin

The Corporation's interests in the Elgin Sub-Basin in the Moncton basin in southeastern New Brunswick consist of a 100% working interest in consolidated lease ONG Lease 13-02C (135,920 gross acres). The lease carried a work commitment of $3,300,360 over its three year term, which has now been fulfilled following the 2014 capital program.

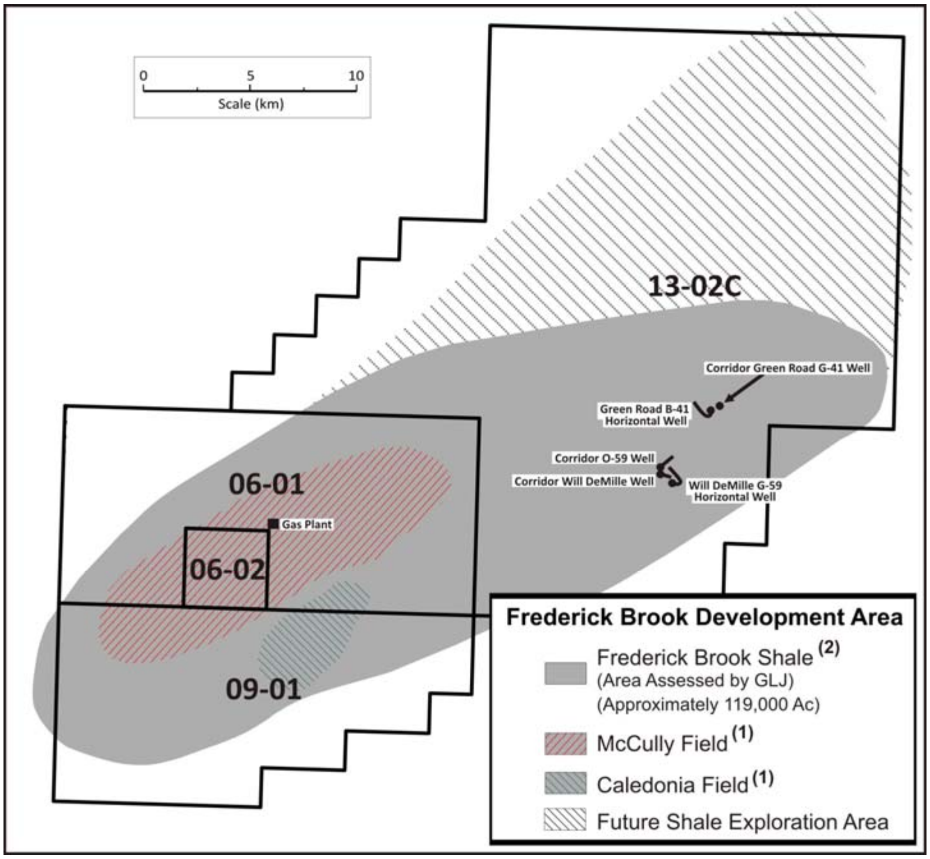
In 2009, Corridor drilled and fracture stimulated with propane the Green Road G-41 (vertical) well and completed initial clean-up flow of two intervals in the upper part of the Frederick Brook formation. The first of the two fracs resulted in the placement of 46 tonnes of proppant in a black shale interval at a depth between 2000 and 2050 metres. The second frac resulted in the placement of 68 tonnes of proppant in a silty interval of the formation containing thin interbeds of sandstone at a depth between 1850 and 1900 metres. Following completion of the fracturing operations, commingled clean-up flow was conducted for the two intervals. At the end of a 57 hour flow period, the well was flowing at a restricted rate of 4.1 mmscfpd, consisting of approximately 85% natural gas and 15% propane frac fluid at a flowing wellhead pressure of 2083 psi. A temperature log confirmed that both intervals were contributing to the flow. These results represented the first significant flow of natural gas from the Frederick Brook formation. In December 2009, Corridor completed segregated testing of the two intervals. Following the initial commingled zone testing, a tubing string with a packer was installed in the well and the two zones were independently tested. The first test interval (a black shale at a depth interval between 2000 and 2050 metres) was flowing natural gas at a stabilized rate of 0.43 mmscfpd at the end of an 83 hour flow period at a final flowing wellhead pressure of 147 psi. The second test interval (a silty, sandy shale at a depth interval between 1850 and 1900 metres) produced a total of 42.4 mmscf of natural gas over a 185 hour flow period at a peak rate of 11.7 mmscfpd and a final stabilized rate of 3.0 mmscfpd at a final flowing wellhead pressure of 699 psi. Corridor re-tested the Green Road G-41 well in December 2010, which produced gas at a constant rate of four mmscfpd for five days at a final flowing pressure of 1306 psi. During the first quarter of 2011, the G-41 well was used to provide gas lift for the Green Road B-41 well and consistently delivered the required rate of 0.5 mmscfpd during a 45 day test, at a final pressure of 2007 psi.

In 2011, Corridor completed the drilling of the vertical Will DeMille O-59 shale gas appraisal well to a total depth of 3188 meters measured depth. Strong gas shows were encountered within Hiram Brook sandstones and the Upper Frederick Brook shale. Based upon initial analysis of well log information, the well intersected at least eight intervals with significantly elevated gas shows that are considered fracture candidates.

In 2012, Corridor retested the Green Road B-41 well, previously drilled by Apache pursuant to the Apache Agreement, and was successful at removing a tool stuck in this well in 2011. While the well did not flow material amounts of gas, a section of the horizontal leg of this well was made available for future fracturing operations. Based on a consensus among third party expert consultants and Corridor's technical staff, the most significant issues previously identified with the B-41 well performance related to the design of the horizontal well in this high-stress environment and the fracture technique used.

For additional information regarding development activities in the Elgin Sub-Basin, see "*General Development of the Business – Three Year History*".

The following map highlights Corridor's interest in New Brunswick (and identifies Corridor's leases) and the areas subject to the GLJ Reserves Report and the GLJ Shale Resources Report:



Notes:

(1) Corridor's reserves as evaluated in the GLJ Reserves Report are located primarily in the McCully Field (covering all of ONG lease 06-02 and part of ONG leases 06-01 and 09-01). Some reserves are also located in the Caledonia Field (covering a small part of ONG lease 09-01).

(2) Corridor's resources that were initially estimated by GLJ in its shale resources report are located in the Frederick Brook shale (covering in large part ONG leases 06-01, 06-02 and 09-01 and partly ONG lease 13-02C).

McCully North

A portion of Corridor's 100% working interest in ONG Lease 06-03 (17,774 acres) located directly above the McCully Field was consolidated with ONG Lease 13-02C effective June 16, 2014. The remaining acreage (26,654 acres) expired on that date.

Gulf of St. Lawrence

The Old Harry prospect has simple 4-way closure covering an area of approximately 43,000 acres, and is one of the largest undrilled prospects in Eastern Canada. Six natural oil seeps have been detected on the ocean surface by satellite, apparently emanating from the flanks of "Old Harry". The prospect lies partly in the Québec sector and partly in the Newfoundland and Labrador sector of the Gulf of St. Lawrence.

Québec

The Corporation holds 100% of two exploration licenses covering 123,550 gross acres over most of the Old Harry prospect, lying in 1,500 feet of water in the Laurentian Channel in Québec. Any drilling in the Québec sector requires agreement between the Québec and Federal governments in order to open up this prospective area of the Gulf to petroleum exploration. In order to permit Corridor to drill on its Québec exploration licence, such agreement would require federal government recognition of such license. On March 24, 2011, an accord between the Government of Canada and the Government of Québec was signed to allow for the development of petroleum resources within the Québec sector of the Gulf of St. Lawrence. The accord contains provisions for the issuance of exploration permits equivalent to the previously held licences to explore for petroleum and natural gas previously issued by the Government of Québec in the accord area. Corridor licenses PG963 and PG964 dated March 29, 1996 are located in the accord area. On October 14, 2014 an announcement on the Prime Minister's website indicated that the governments of Canada and Québec "are in a good position to table the legislative framework to implement the Canada-Québec Accord". As of the date hereof, no further announcements have been made with respect to the accord legislation.

In August 2003, Corridor announced the execution of an option agreement with Hydro-Québec whereby Hydro-Québec received the right to obtain a minimum of 18.75% working interest in the Old Harry farm-in opportunity on the same terms as are ultimately negotiated with an operating partner.

The Québec Government announced on May 30, 2014 that the entire oil and gas sector would be subject to a comprehensive strategic environmental assessment ("**Québec SEA**") process. The Québec SEA will help assess the likely consequences of oil and gas development and estimate the economic effects of development of the oil and gas sector in Québec. Through the Québec SEA, the Québec Government intends to undertake a comprehensive review and modernization of legislation and the regulatory framework governing oil and gas exploration and development. Only after the completion of the Québec SEA will the potential of such resources be assessed and potentially developed.

Newfoundland and Labrador

Corridor holds a 51,780 hectare (127,948 acres) exploration licence situated on the eastern end of the Old Harry prospect off the west coast of Newfoundland and Labrador in the Gulf of St. Lawrence. The licence carried a minimum work commitment of $1,521,000 to be conducted over a five year initial term. This work commitment has now been fulfilled. Acquisition of this licence is part of Corridor's long-term efforts to open up hydrocarbon exploration offshore in the Gulf of St. Lawrence. On July 22, 2013, the C-NLOPB amended Corridor's Exploration Licence 1105 to extend Period 1 of the license from seven to eight years (January 15, 2016). Corridor's exploration license also has a provision whereby Corridor can extend this drilling period by an additional year (January 13, 2017) with the payment of a $1 million deposit.

In October 2010, Corridor completed a geohazard survey to identify potential seabed hazards to drilling with the goal to ensure that any future exploration by Corridor on the Old Harry prospect is conducted in a safe and responsible manner.

In February, 2011, Corridor submitted to the C-NLOPB a Project Description for the drilling of an exploration well on the Old Harry prospect. The Project Description, submitted pursuant to the CEAA, commenced the official regulatory process for obtaining the necessary approvals to permit Corridor to drill an offshore well then planned for mid-2012 and early 2014. Initially, the C-NLOPB determined that Corridor's application would be subject to a project specific screening level EA. After receiving over 50 comments from the public, the C-NLOPB, although it did not anticipate any significant adverse environmental impacts, recommended to the federal Minister of Environment for Canada that the project be referred to a mediator or review panel. On August 15, 2011, the Minister of Environment responded to this recommendation, noting that the concerns raised in the public comments related to broader policy issues and a project specific EA was not the most appropriate mechanism to address these broader issues and directed that, instead, the SEA be updated. Subsequently, the C-NLOPB announced that the EA would be subject to additional public consultation led by an Independent Reviewer and that the SEA update and the Old Harry EA processes would take place concurrently.

In December 2011, Corridor submitted to the C-NLOPB its completed EA for the Old Harry exploration well and received regulatory comments from the C-NLOPB review of the document in April 2012. Corridor submitted a revised EA document addressing the regulatory comments in February 2013.

On February 27, 2012, the C-NLOPB issued a decision to dismiss Corridor's application for a prohibition order in respect of Corridor's EL 1105. The application was made by Corridor as a result of what Corridor considered to be duplicative regulatory processes, due to Corridor being subject to a project specific EA (in respect of old Harry) while a concurrent SEA took place. If granted, the prohibition order would have effectively provided Corridor a "time-out" on its licence during the conduct of the SEA.

The C-NLOPB also decided on February 27, 2012 that the SEA update should be completed before proceeding with the review of the Old Harry EA for the single exploration well proposed to be drilled within Corridor's EL 1105.

On July 6, 2012, the Minister of Environment designated Corridor’s Old Harry EA as a designated project under the CEAA and, as a result, the screening for the project must be continued and completed as if the CEAA had not been repealed.

On February 28, 2013, further to the update of the 2005 Strategic Environmental Assessment and 2007 Amendment for the Western Newfoundland and Labrador Offshore Area Strategic Environmental Assessment, the C-NLOPB announced it would be preparing a draft SEA update that would be released for public review in the second quarter of 2013.

On November 5, 2013, C-NLOPB provided additional comments to Corridor in respect of the Old Harry EA, and Corridor provided responses to C-NLOPB in respect of these comments on November 29, 2013.

On May 5, 2014, the C-NLOPB issued the SEA update for the Western Newfoundland and Labrador offshore area. This report states that "petroleum exploration activity generally can proceed in the Western Newfoundland and Labrador offshore area with the application of standard mitigation measures currently applied." The C-NLOPB also indicated that additional consultations on Corridor's Old Harry EA are required in order for the C-NLOPB to finalize the Old Harry EA.

Corridor is in discussions with the C-NLOPB regarding the extension of its exploration license EL-1105 to complete its consultations on the Old Harry EA. Corridor expects to conclude these discussions in 2015.

For additional information regarding Corridor's interest in the Gulf of St. Lawrence, see "*General Development of the Business – Three Year History*".

Anticosti Island, Québec

Corridor has a 21.67% interest in the Anticosti Joint Venture, which holds a 100% working interest in 1,530,943 gross acres in more than 30 exploration licenses covering lands across much of

Anticosti Island. Prior to the establishment of the Anticosti Joint Venture, Corridor held working interests ranging from 50% to 100% in these licenses.

Anticosti Joint Venture

On April 1, 2014, Corridor announced the establishment of the Anticosti Joint Venture with Ressources Québec, Pétrolia and M&P. The purpose of this joint venture is to appraise and potentially develop hydrocarbon resources on Anticosti Island.

The Anticosti Joint Venture was formed by, among other things (including entering into the securityholders agreement and the limited partnership agreement), each of Ressources Québec, Pétrolia and M&P and Corridor: (i) subscribing for shares of Anticosti General Partner Inc.; and (ii) subscribing for units of Anticosti Hydrocarbons, pursuant to which Corridor acquired an interest in the Anticosti Joint Venture by transferring all of its right, title and interest in and to its Anticosti exploration licenses covering 891,906 acres, and redeeming certain limited partnership units in exchange for a cash payment from Anticosti Hydrocarbons to Corridor in the amount of $15.26 million. The interests of the participants in the Anticosti Joint Venture are Ressources Québec (35%), Corridor (21.67%), Pétrolia (21.67%) and M&P (21.67%).

M&P has the right to exit from Anticosti Hydrocarbons after: a minimum of $35 million has been expended by Anticosti Hydrocarbons; the earlier of the completion of a minimum of 15 stratigraphic wells or $25 million has been expended on drilling stratigraphic wells; a minimum of one well has been drilled and fracture stimulated; and, all technical data and results accomplished at that point have been received. The exercise of M&P of this exit right would be based solely on a reasonable analysis and interpretation of the technical data and results of the first phase of the Anticosti Joint Venture exploration program accomplished at that time. In such event, M&P would relinquish its entire interest in Anticosti Hydrocarbons for no consideration. If this were to occur, in completing the first phase, Ressources Québec would fund up to $13.26 million of the remaining commitment and would then own 50% of Anticosti Hydrocarbons. Corridor and Pétrolia would each become required to pay up to $3.37 million, subject to dilution penalties, and each would then own 25% of Anticosti Hydrocarbons.

Anticosti Hydrocarbons is managed by the Anticosti General Partner. Each of the participants is entitled to appoint one member to the board of directors of the Anticosti General Partner, and a fifth and independent director shall be appointed with the unanimous consent of the partners. Pursuant to a contract operating agreement, Pétrolia has been appointed Contract Operator and M&P has been designated as Assistant Technical Operator. Each of the participants has equal representation on the operating committee and technical services committee of the Anticosti General Partner. Anticosti Hydrocarbons has been organized to take advantage of the combined expertise of all the partners so that the programs are implemented in a safe, effective and environmentally responsible manner.

The first phase of the Anticosti Joint Venture's exploration program consists of drilling 15-18 stratigraphic corehole wells followed by three wells with multiple fracture stimulations. The program is designed to further explore the Macasty Formation on Anticosti Island, which is the lateral equivalent of the Utica Formation in Eastern Ohio.

In 2014, five stratigraphic coreholes were drilled into the Macasty Formation as part of the first phase of the Anticosti Joint Venture's exploration program. Corridor is encouraged with the initial results of the program, as the results of the core analysis and petrophysical log surveys generally meet or exceed the Corporation’s expectations. The stratigraphic corehole program experienced start-up delays due to the adoption of a new regulatory framework and the program was temporarily suspended during the winter season. The Anticosti Joint Venture intends to resume the drilling of the remaining approved stratigraphic corehole wells in the spring of 2015, to complete this program during the year, and to drill the three horizontal wells in 2016. The results of all the cores will help assess the rock quality and determine the optimal location for the three test wells.

See "*Industry Conditions - Environmental Regulation – Québec*" for a description of the current regulatory regime applicable to Corridor in respect of its interests on Anticosti Island (through the Anticosti Joint Venture), and "*Resources Information - Sproule Anticosti Resources Report*" for information regarding the resources associated with the Anticosti Joint Venture.

Anticosti Working Interest History

In 2009, Corridor's Anticosti licenses were converted from exploration licenses to underground storage licenses with new 10 year terms. The underground storage licenses permit the Anticosti Joint Venture to explore for oil and natural gas in a manner similar to the previous exploration licenses.

In July 2011, the Québec Government notified Corridor that the holder of a licence to explore for petroleum, natural gas and underground reservoirs is exempted from performing the work required under the *Mining Act* until a later date to be determined by the Minister. This date was originally scheduled to be no later than June 13, 2014, however, the Québec Government recently extended this date indefinitely through Bill 5 – *An Act to amend the Act to limit oil and gas activities and other legislative provisions*. This essentially provides Corridor with a time-out on its Québec licencesuntil the Quebec SEA and Anticosti SEA are completed.

Between June and early September 2010, Corridor, in partnership with Pétrolia, undertook a three-well exploration drilling program on Anticosti Island. The primary objective of the program was to evaluate the oil potential of the Trenton Black River and Mingan Group formations in the Jupiter, Chaloupe, Saumon and Bell or Macaire prospects located in the east central part of Anticosti Island. Another objective for the Anticosti drilling program was to core part of the oil-bearing Macasty shale overlying the Trenton/Black River Formation in the Chaloupe well. A conventional core of approximately 27 metres was recovered and analysis of the reservoir character and fluid content of the core was undertaken.

In June 2011, Corridor and Pétrolia retained Sproule to estimate the quantity of hydrocarbon resource contained within the Macasty Formation shales on Anticosti Island with the goal of using the assessment to determine whether to engage in further investigation into these resources. The Sproule Anticosti Resources Report categorized the resources as undiscovered petroleum initially-in-place, since insufficient information was available at such time to estimate the technical or economically recoverable amount of resources within the study area. See "*Resources Information – Sproule Anticosti Resources Report"*.

On February 21, 2012, the Corporation announced results of a study by Schlumberger Canada comparing the petrophysical properties of the Utica shale in the Ohio Geological Survey CO2 #1 well with those of the Macasty Formation (a geological equivalent to the Utica) in the Pétrolia /Corridor Chaloupe #1 well on Anticosti Island, Québec. The results of the study demonstrate that the majority of rock parameters of the Macasty Formation are very similar to those of the Utica Formation, including net pay, total organic carbon, clay content and hydrocarbon saturation. This data suggests that the rock properties of the Macasty shale are similar to those of the Utica shale in Ohio where a number of companies are active.

On September 4, 2012, Corridor announced that it was conducting an exploration program on Anticosti Island with its partner, Pétrolia, designed to advance the understanding of the development potential of the vast shale oil prospect on Anticosti Island. The exploration program consisted of three components, including: (i) drilling three stratigraphic coreholes through the Macasty Formation at strategic locations across the Island; (ii) an extensive well core and cuttings sampling and analysis project that included 15 previously drilled Anticosti wells to map the organic content and maturity of the shale; and (iii) a baseline study of the Anticosti groundwater system that consisted of drilling and monitoring approximately 14 water wells (13 water wells actually drilled) as well as conducting a number of surface water studies.

In January 2013, Corridor announced the initial results of the Macasty core analyses from the Pétrolia/Corridor Princeton Lake and High Cliff wells that were drilled in the fall of 2012 on Anticosti Island. The Princeton Lake and High Cliff wells intersected 90 meters and 57 meters of highly organic Macasty Formation, respectively. The cores were sampled at 50 cm intervals and analyzed by Weatherford (Princeton Lake) and TerraTek Labs (High Cliff). The results provided an average of 4.0% TOC in both wells. It is important to note that TOC averaged 5.5% through a 10 meter section at the High Cliff well, with the highest TOC measured at 7.1%. At the Princeton Lake well, TOC averaged 6.0% through a 10 meter section with the highest TOC measured at 7.5%. The results include hydrocarbon saturation levels as measured by the S1 (free hydrocarbons within pore spaces) at an average of 5.7 mg/g at Princeton Lake and 4.6 mg/g at High Cliff through the 10 meter sections. The final corehole drilled was at Oil River. It intersected 30 meters of organic Macasty Formation and averaged approximately 4% TOC. The analyses confirmed that the Macasty Formation is within the oil/condensate window at all locations. These results are very positive indicators for the hydrocarbon production potential of the Macasty Formation.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Reserves Data

The statement of reserves data and other oil and gas information set forth below is dated February 18, 2015 and is a summary of information contained in the GLJ Reserves Report, which has an effective date of December 31, 2014 and a preparation date of February 18, 2015. The GLJ Reserves Report was prepared in accordance with the COGE Handbook and NI 51-101. The reserves data summarizes the natural gas, oil and natural gas liquids reserves of Corridor and the net present values of future net revenue for these reserves using GLJ's forecast prices and costs. Assumptions and qualifications applicable to the evaluation and contained in the GLJ Reserves Report are set forth in the notes to the tables. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Corridor believes is important to the readers of this information.

The information relating to the natural gas, oil and natural gas liquids reserves of the Corporation contains forward-looking statements relating to future net revenues, forecast capital expenditures, future development plans and costs related thereto, forecast operating costs, anticipated production and abandonment costs. Refer to "*Forward-Looking Statements*" and "*Risk Factors*".

All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimates of future net revenues presented in the following tables represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Reserves Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Reserves Report. The recovery and reserves estimates of the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated. For more information on the risks involved, see "*Forward-Looking Statements*" and "*Risk Factors*".

In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices "A" and "B" hereto, respectively.

All of Corridor's reserves are located in the McCully Field and the Caledonia Field in New Brunswick, Canada.

Please note that rounding errors may occur in the tables set forth below in the statement of reserves data and other oil and gas information.

Reserves Data

Summary of Oil and Gas Reserves as of December 31, 2014 (Forecast Prices and Costs)

Reserves Category	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent Basis[1]	
	Gross (mbbl)	Net (mbbl)	Gross (bscf)	Net (bscf)	Gross (mbbl)	Net (mbbl)	Gross (mboe)	Net (mboe)
Proved Reserves								
Developed Producing	-	-	21.3	20.8	27	27	3,569	3,493
Developed Non Producing	-	-	-	-	-	-	-	-
Undeveloped	87	84	23.8	23.1	30	30	4,084	3,962
Total Proved Reserves	87	84	45.1	43.9	58	56	7,654	7,455
Probable Reserves	43	42	20.9	20.2	27	26	3,553	3,433
Total Proved Plus Probable Reserves	130	126	66.0	64.1	84	82	11,207	10,888
Possible Reserves [2]	434	382	120.9	99.8	155	127	20,744	17,142
Total Proved Plus Probable Plus Possible Reserves [2]	564	508	186.9	163.9	239	209	31,951	28,030

Notes:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six mscf of natural gas being equal to one barrel of oil.

(2) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Summary of Net Present Value of Future net Revenue as of December 31, 2014 Before and After Income Taxes[1] (Forecast Prices and Costs)

Reserves Category	Before Income Taxes[1] Discounted at (%/Year)					Unit Value Before Income Tax Discounted at 10%/Year[2]	
	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)	$/boe	$/mscf
Proved Reserves							
Developed Producing	88.9	70.3	58.2	49.8	43.8	16.65	2.77
Developed Non Producing	-	-	-	-	-	-	-
Undeveloped	62.9	28.6	11.0	1.7	(3.3)	2.78	0.46
Total Proved Reserves	151.8	98.9	69.2	51.5	40.5	9.28	1.55
Probable Reserves	134.6	72.3	43.8	29.1	20.8	12.75	2.13
Total Proved Plus Probable Reserves	286.4	171.2	112.9	80.6	61.2	10.37	1.73
Possible Reserves [3]	603.3	239.4	115.5	62.5	36.4	6.74	1.16
Total Proved Plus Probable Plus Possible Reserves [3]	889.7	410.6	228.5	143.1	97.6	8.15	1.36

Reserves Category	After Income Taxes(1) Discounted at (%/Year)				
	0% ($MM)	5% ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proved Reserves					
Developed Producing	88.9	70.3	58.2	49.8	43.8
Developed Non Producing	-	-	-	-	-
Undeveloped	62.9	28.6	11.0	1.7	(3.3)
Total Proved Reserves	151.8	98.9	69.2	51.5	40.5
Probable Reserves	106.4	60.5	38.5	26.6	19.5
Total Proved Plus Probable Reserves	258.2	159.4	107.6	78.0	59.9
Possible Reserves (3)	434.6	171.9	82.3	44.1	25.5
Total Proved Plus Probable Plus Possible Reserves (3)	692.8	331.3	189.9	122.2	85.4

Notes:

(1) The estimated value of future net revenue does not represent the fair market value of Corridor's reserves.

(2) Unit values are based on Corridor's net reserves.

(3) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Additional Information Concerning Future Net Revenue (undiscounted)
as of December 31, 2014
(Forecast Prices and Costs)

Reserves Category	Revenue ($MM)	Royalties ($MM)	Operating Costs ($MM)	Development Costs ($MM)	Abandonment and Reclamation Costs ($MM)	Future Net Revenue Before Income Taxes ($MM)	Income Taxes ($MM)	Future Net Revenue After Income Taxes ($MM)
Total Proved Reserves	326.7	8.1	76.2	79.0	11.7	151.8	-	151.8
Total Proved Plus Probable Reserves	529.3	13.5	119.3	96.3	13.7	286.4	28.2	258.2
Total Proved Plus Probable Plus Possible Reserves (1)	1,627.7	207.8	264.4	238.7	27.1	889.7	196.9	692.8

Note:

(1) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Net Present Value of Future Net Revenue By Production Group
as of December 31, 2014
(Forecast Prices and Costs)

Reserves Category	Production Group	Future Net Revenue Before Income Taxes (discounted at 10%/yr) ($MM)	Unit Value(3)	
			($/boe)	($/mscf)
Total Proved Reserves	Light and Medium Crude Oil (1)	3.7	40.84	6.81
	Natural Gas(2)	65.4	8.89	1.48
	Total Proved Reserves	69.2	9.28	1.55
Total Proved Plus Probable Reserves	Light and Medium Crude Oil(1)	6.9	50.86	8.48
	Natural Gas(2)	106.0	9.86	1.64
	Total Proved Plus Probable Reserves	112.9	10.37	1.73
Total Proved Plus Probable Plus Possible Reserves (4)	Light and Medium Crude Oil(1)	10.1	18.49	3.08
	Natural Gas((2)	218.3	7.94	1.32
	Total Proved Plus Probable Plus Possible Reserves	228.5	8.15	1.36

Notes:

(1) Including solution gas and other by-products.

(2) Including by-products but excluding solution gas from oil wells.

(3) Unit values are based on Corridor's net reserves.

(4) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

Pricing Assumptions

The following table summarizes the prices and factors used by GLJ in the GLJ Reserves Report in calculating the net present value of future net revenue, effective as at January 1, 2015.

Year	Brent Blend Crude Oil FOB North Sea ($US/bbl)	Exchange Rate US$/Can$	Inflation rate	Henry Hub Gas Price US$/mmbtu	Nova Scotia Goldboro Gas Price $/mmbtu	McCully Gas Price $/mscf
2015	67.50	0.8500	2%	3.31	6.56	6.72
2016	82.50	0.8750	2%	3.75	6.30	6.70
2017	87.50	0.8750	2%	4.00	6.02	6.40
2018	90.00	0.8750	2%	4.25	4.90	5.20
2019	95.00	0.8750	2%	4.50	5.18	5.50
2020	100.00	0.8750	2%	4.75	5.46	5.80
2021	101.35	0.8750	2%	5.00	5.74	6.10
2022	103.38	0.8750	2%	5.25	6.02	6.40
2023	105.45	0.8750	2%	5.50	6.29	6.70
2024	107.56	0.8750	2%	5.68	6.49	6.91
Thereafter	+2%/yr	0.8750	2%	+2%/yr	+2%/yr	+2%/yr

The McCully gas price is used by GLJ in calculating the net present value of Corridor's natural gas net revenues. The McCully gas price is determined by adjusting the Nova Scotia Goldboro gas prices to reflect premiums received at Algonquin city-gate (Corridor's pricing point), transportation costs and heat content.

Reserves Reconciliation

The following table provides a reconciliation of Corridor's gross reserves of natural gas, oil or natural gas liquids for the year ended December 31, 2014, using forecast prices and costs.

Reserves Reconciliation of Corporation Gross Reserves
By Principle Product Type
(Forecast Prices and Costs)

	Light and Medium Oil			Natural Gas			Natural Gas Liquids			Total oil Equivalent Basis		
	Gross Proved (mbbl)	Gross Probable (mbbl)	Gross Proved Plus Probable (mbbl)	Gross Proved (bscf)	Gross Probable (bscf)	Gross Proved Plus Probable (bscf)	Gross Proved (mbbl)	Gross Probable (mbbl)	Gross Proved Plus Probable (mbbl)	Gross Proved (mboe)	Gross Probable (mboe)	Gross Proved Plus Probable (mboe)
December 31, 2013	87	174	260	60.5	37.8	98.3	77	48	126	10,246	6,527	16,773
Technical Revisions	0	(130)	(130)	(12.9)	(16.9)	(29.8)	(16)	(22)	(38)	(2,164)	(2,973)	(5,138)
Production				(2.5)	-	(2.5)	(3)	-	(3)	(428)	-	(428)
December 31, 2014	**87**	**43**	**130**	**45.1**	**20.9**	**66.0**	**58**	**27**	**84**	**7,654**	**3,553**	**11,207**

ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Timing of Undeveloped Reserves Assignments

The following table shows the timing of the assignment of proved undeveloped reserves and probable undeveloped reserves of natural gas and crude oil in respect of Corridor's interests in the McCully Field and Caledonia Field. The Corporation attributes proved and probable undeveloped reserves based on the accepted engineering and geological practices as defined under NI 51-101. The practices include the determination of reserves based on the presence of a commercial test rate from production tests, or extensions of known accumulations supported by a combination of geological, geophysical and engineering data.

Proved Undeveloped Reserves	Light & Medium Oil (mbbl)		Natural Gas (bscf)		Natural Gas Liquids (mbbl)		Total Oil Equivalent [(1)] (mboe)	
	First Attributed[(2)]	Total at Year-end	First Attributed[(2)]	Total at Year-end	First Attributed[(2)]	Total at Year-end	First Attributed[(2)]	Total at Year-end
Prior	-	87	-	36.7	-	47	-	6,257
2012	-	87	1.0	36.3	1	46	167	6,183
2013	-	87	3.0	39.4	4	50	501	6,699
2014	-	87	0.1	23.8	-	30	10	4,084

Notes:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six mscf of natural gas being equal to one barrel of oil.

(2) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year

These reserves are classified as proved undeveloped if they are expected to be recovered, with a high degree of certainty, from new wells on previously undrilled acreage with untested reservoir characteristics, or they are reserves from existing wells that require major capital expenditures to bring them on production.

Probable Undeveloped Reserves	Light & Medium Oil (mbbl)		Natural Gas (bscf)		Natural Gas Liquids (mbbl)		Total Oil Equivalent [(1)] (mboe)	
	First Attributed[(2)]	Total at Year-end	First Attributed[(2)]	Total at Year-end	First Attributed[(2)]	Total at Year-end	First Attributed[(2)]	Total at Year-end
Prior	-	434	3.5	38.0	4	49	586	6,819
2012	-	174	0.2	31.7	-	41	33	5,505
2013	-	174	1.5	32.9	2	42	251	5,705
2014	-	43	0.0	15.9	-	20	4	2,705

Notes:

(1) Natural gas has been converted to barrels of oil equivalent on the basis of six mscf of natural gas being equal to one barrel of oil.

(2) "First Attributed" refers to reserves first attributed at year-end of the corresponding fiscal year

These reserves are classified as probable undeveloped when analysis of drilling, geological, geophysical and engineering data does not demonstrate them to be proved under current technology and existing economic conditions; however, this analysis does suggest that there is a likelihood of their existence and future recovery. Corridor intends to develop its proved undeveloped reserves and probable undeveloped reserves during the next five years.

Significant Factors or Uncertainties

Estimates of economically recoverable oil and natural gas reserves (including natural gas liquids) and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as capital expenditures, commodity prices, production performance of re-completed wells and well re-completion success rates, the assumed effects of regulation by government agencies (including royalty regimes) and future operating costs. All of these estimates may vary from actual results. Estimates of the recoverable oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. The Corporation's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates, and such variances could be material, resulting in the delay or acceleration of development activities, as the case may be, see "*Risk Factors*".

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue calculated using forecast prices and costs, undiscounted, attributable to the reserve categories noted below.

Reserve Category	2015 ($MM)	2016 ($MM)	2017 ($MM)	2018 ($MM)	2019 ($MM)	2020 ($MM)	Remainder ($MM)	Total Undiscounted ($MM)	Total Discounted at 10% ($MM)
Proved Reserves	-	1.0	21.2	16.3	28.0	12.4	-	79.0	54.9
Proved Plus Probable Reserves	-	1.0	21.2	16.3	28.0	27.0	2.7	96.3	64.1

Corridor's 2015 capital expenditure program does not include any capital spending in New Brunswick due to the hydraulic fracturing moratorium in New Brunswick. Future development costs are expected to resume in 2017 and may be funded with a combination of cash flow, debt, equity and asset sales or joint venture partnerships.

RESOURCES INFORMATION

Resources do not constitute, and should not be confused with, reserves. Actual reserves and resources will vary from the reserve and resources estimates, and those variations could be material.

Sproule Anticosti Resources Report

The Sproule Anticosti Resources Report is made in respect of the properties on Anticosti Island owned by the Anticosti Joint Venture. Corridor has a 21.67% interest in the Anticosti Joint Venture.

In 2011, Corridor and Pétrolia retained Sproule to estimate the quantity of the un-risked undiscovered petroleum initially-in-place contained within the Macasty Formation in Anticosti Island with the goal of using the assessment to determine whether to engage in further investigation into these resources. Subsequent to the preparation of the Sproule Anticosti Resources Report, Corridor and Pétrolia transferred their interests in these properties to the Anticosti Joint Venture. See "*Description of the Properties – Anticosti Island, Québec*".

The Sproule Anticosti Resources Report was conducted in accordance with the COGE Handbook and NI 51-101 and addressed only the undiscovered petroleum initially-in-place, since insufficient information was available at such time to estimate the technical or economically recoverable amount of resources within the study area. Sproule subsequently reviewed the pertinent data collected between June 1, 2011 and December 31, 2012 and made no changes to the original resource estimates provided in the Sproule Anticosti Resources Report. Three core holes were drilled in the fall of 2012 and laboratory results were provided to Sproule on March 14, 2013. In a letter dated November 19, 2013, Sproule indicated that, in their opinion, incorporating the new data from the core results would not result in a material change to the Sproule Anticosti Resources Report. During the summer and fall of 2014, the Anticosti Joint Venture drilled five core holes pursuant to the first phase of the Anticosti Joint Venture's exploration program. The results from the five core holes were provided to Sproule and the Anticosti Joint Venture expects to receive an updated Sproule Anticosti Resources Report in April 2015.

NI 51-101 disclosure requires that the resource estimates must be classified according to the COGE Handbook definitions and disclosed in the most specific category. Under these definitions, Sproule classified the total petroleum initially-in-place as undiscovered resources, based on the following:

(i) a core of the Macasty shale from the Chaloupe well contained residual oil; (ii) the Macasty shale has not been flow tested from any well on Anticosti Island; (iii) the resources are inferred to exist based on the interpretation and mapping of limited pyrolysis, core, well log and seismic data and; (iv) this is an unconventional shale oil resource that will require a stimulated completion for evaluation and, until an appropriately researched project has been undertaken to identify and evaluate potentially recoverable volumes, it is premature to speculate whether the Macasty contains recoverable or unrecoverable resources.

The Anticosti Joint Venture was established on April 1, 2014 and all of Corridor's and Pétrolia's interests in Anticosti Island were transferred to the Anticosti Joint Venture. The following table provides a summary of the Sproule Anticosti Resources Report in respect of the properties held by the Anticosti Joint Venture:

Estimates of Total Petroleum Initially-In-Place
Macasty Shale, Anticosti Island, Québec
As At June 1, 2011

Classification	Gross Anticosti Joint Venture Interest Lands	Low Estimate (P90) (1) Bboe(4)	Best Estimate (P50) (2) Bboe(4)	High Estimate (P10) (3) Bboe(4)
Undiscovered Petroleum Initially-In-Place(5)	Total Lands	21.4	33.9	53.9

Notes:

(1) The probability that the quantity actually in place is equal to or greater than the estimate is 90%.
(2) The probability that the quantity actually in place is equal to or greater than the estimate is 50%.
(3) The probability that the quantity actually in place is equal to or greater than the estimate is 10%.
(4) These resources are reported as billions of barrels of oil equivalent to reflect uncertainty of hydrocarbon type across the island.
(5) Undiscovered petroleum initially-in-place (equivalent to "undiscovered resources") are those quantities of petroleum that are estimated, on a given date, to be contained in accumulations yet to be discovered. The recoverable portion of undiscovered petroleum initially-in-place is referred to as "prospective resources", the remainder as unrecoverable. Undiscovered resources carry discovery and development risks. The reported volumes are unrisked. There is no certainty that any portion of these resources will be discovered. A recovery project cannot be defined for this volume of undiscovered petroleum initially-in-place at this time. There is no certainty that it will be commercially viable to produce any portion of the resources.

Corridor does not have any working interest in the Anticosti properties and its interest is limited to a 21.67% interest in the Anticosti Joint Venture.

Corridor believes the significant positive factors relevant to the estimates are:

- the 2012 and 2014 coring programs have shown that the Macasty is rich in TOC, has generated significant amounts of hydrocarbons and has favourable porosity and permeability over much of the Island;
- the Macasty shale is stratigraphically equivalent to the Utica shale of the St. Lawrence Lowlands of Québec, which has been reported to have produced oil and gas on test;
- core analysis indicates that the Macasty has similar petrophysical and geochemical characteristics to the Utica fields found in the north-east, US; and
- the Macasty shale is a prolific source rock which is interpreted to be within the oil/condensate generation window over approximately three quarters of the island.

GLJ Shale Resources Report

In May 2009, Corridor initially retained GLJ to estimate the quantity of shale gas resources contained within the Frederick Brook shale in the McCully Field and Elgin Sub-Basin of southern New Brunswick with the goal of assisting Corridor to develop a longer term plan for the appraisal and potential development of this vast resource. See "*Description of the Properties – New Brunswick Lands - Elgin Sub-Basin*". Effective June 1, 2009, GLJ provided Corridor with a best estimate of PIIP which was based on all available seismic and well information within the study area provided by Corridor to GLJ at the time. This report was conducted in accordance with the COGE Handbook and NI 51-101 and addressed only the discovered PIIP, as insufficient information was available at such time to estimate the technical or economically recoverable amount of shale gas within the study area.

Corridor conducted a fracturing program in 2014 to further evaluate the shale gas potential of the Frederick Brook shale. The program resulted in the fracture stimulation of three shale intervals in the Frederick Brook and the results have demonstrated that the Frederick Brook shale is productive from at least six different sub-intervals across a distance of 25 kilometers. As of the date hereof, two wells are following the F-58 production profile and have consistent 30-day production volumes. The F-58 McCully well was fracture stimulated with water in a single 11 tonne treatment and placed on production in 2008. It is still producing at an estimated average rate of 180 mscf/d with a 1.8% annual decline. The Corporation expects F-58 to recover a total of 1.5 bscf (proved plus probable estimate effective December 31, 2014). GLJ was not engaged in 2014 to provide an update to the original resource estimates provided in 2009 as the results of the 2014 program are preliminary at this time.

Consistent with its initial report in 2009 (and confirmed on March 25, 2014), GLJ continues to provide a best estimate of Corridor's gross interest in the Frederick Brook shale (as described in the map in "*Description of the Properties – New Brunswick Lands - Elgin Sub-Basin*") as of March 30, 2015 of 67.3 tscf of discovered petroleum initially-in-place (or discovered resources), which is unrecoverable. "Discovered unrecoverable petroleum initially-in-place", the equivalent of "discovered unrecoverable resources", refers to that portion of discovered petroleum initially-in-place which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.

A recovery project cannot be defined for Corridor's volume of discovered petroleum initially-in-place at this time. Corridor has been seeking a joint venture partner to participate in the exploration of the Frederick Brook shale. Corridor’s program to select a joint venture partner is on-going and has been negatively impacted by low natural gas prices and uncertainty surrounding New Brunswick regulations applicable to shale gas development activities.

There is no certainty that it will be commercially viable to produce any portion of these discovered resources.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

As at December 31, 2014, Corridor had an interest in 38 gross (27.5 net) producing and non-producing natural gas and oil wells as follows:

	Producing		Non-producing	
	Gross	Net	Gross	Net
Crude Oil Wells				
McCully Field......................	-	-	-	-
Caledonia Field …	-	-	1.0	1.0
Subtotal................................	-	-	1.0	1.0
Natural Gas Wells				
McCully Field......................	32.0	22.5	5.0	4.0
Caledonia Field....................	-	-	-	-
Subtotal................................	32.0	22.5	5.0	4.0
Total.......................................	32.0	22.5	6.0	5.0

Note:

(1) Non-producing wells in which Corridor has an interest are located no further than 15 kilometres from proposed gathering systems, pipelines or other means of transportation. Excluded are McCully wells C-75 and H-28, and all Elgin wells.

Properties with No Attributed Reserves

The following table sets forth the gross area and net area of unproved properties held by Corridor as at March 30, 2015.

Location	Gross Acres	Net Acres
McCully and Caledonia Fields, New Brunswick (1)	77,461	59,164
Elgin Sub-Basin, New Brunswick (1)	135,920	135,920
Gulf of St. Lawrence, Québec (2)	123,550	123,550
Gulf of St. Lawrence, Newfoundland and Labrador	127,948	127,948
Anticosti Joint Venture (3)	1,530,943	331,704
Total	**1,995,822**	**778,286**

Notes:

(1) On March 27, 2015, the New Brunswick Government enacted *An Act to Amend the Oil and Natural Gas Act* which creates a moratorium on all forms of hydraulic fracturing in New Brunswick, While the moratorium is in effect, Corridor's ability to increase its natural gas production or to attract a joint venture partner to participate in the exploration of the Frederick Brook shale is significantly reduced.

(2) In order for Corridor to drill on its Québec exploration licence, an agreement between the Québec and Federal governments is required and this agreement requires federal government recognition of such license. On March 24, 2011 an accord between the Government of Canada and the Government of Québec was signed to allow for the development of petroleum resources within the Québec sector of the Gulf of St. Lawrence. The accord contains provisions for the issuance of exploration permits equivalent to the previously held licences to explore for petroleum and natural gas previously issued by the Government of Québec in the accord area.

(3) Corridor has a 21.67% interest in the Anticosti Joint Venture.

The GLJ Reserves Report evaluates mostly ONG Lease 06-02, however, some proved reserves are located in ONG Lease 09-01 and ONG Lease 06-01. Since only a small portion of these leases were evaluated the acreage for these leases is included in unproved properties in the McCully and Caledonia Fields.

None of Corridor's rights to explore, develop or exploit any of unproved properties will expire before December 31, 2015. The development of properties with no attributed reserves can be affected by a number of factors including, but not limited to, project economics, regulatory approvals and government regimes, forecasted price assumptions, cost estimates and access to infrastructure. These and other factors may lead to the delay or acceleration of projects related to these properties.

Forward Contracts

Corridor has agreed to sell all of its natural gas produced from the McCully Field and surrounding areas in southern New Brunswick pursuant to a long term agreement with Repsol Energy Canada Ltd. This agreement became effective on April 1, 2009 and provides Corridor with year round access to natural gas markets in Maritimes Canada and the U.S. Northeast and allows it to receive corresponding market prices including those in periods of peak demand. The agreement provides the basis for Corridor to sell present and future production at market prices (referenced to Algonquin city-gate less pipeline transportation costs on M&NP and Algonquin Pipeline), as it expands its exploration and development of the natural gas potential of sandstone and shale reservoirs in the McCully Field and Elgin Sub-basin.

The Corporation has a commitment to purchase 6,500 mmbtu per day of transportation on the Canadian side of the M&NP from November 1, 2014 to October 31, 2015.

Corridor's natural gas production is subject to the following forward sale agreements, being an agreement for the sale of: (i) 2,000 mmbtupd from January 1, 2015 to January 31, 2015 at an average price of $US12.47/mmbtu; (ii) 1,000 mmbtupd from February 1, 2015 to February 28, 2015 at an average price of $US12.52/mmbtu; (iii) 1,000 mmbtupd from March 1, 2015 to March 31, 2015 at an average price of $US8.65/mmbtu; (iv) 4,000 mmbtupd from November 1, 2014 to March 31, 2015 at an average price of $US11.74/mmbtu; and (v) 2,500 mmbtupd from November 1, 2015 to March 31, 2016 at an average price of $US9.25/mmbtu.

Abandonment & Reclamation Costs

The total future abandonment and site reclamation costs are based on management's estimate of costs to remediate, reclaim and abandon wells and facilities having regard to Corridor's working interest and the estimated timing of the costs to be incurred in future periods. Corridor has developed a process to calculate these estimates, which considers applicable regulations, actual and anticipated costs, type and size of the well or facility and the geographic location. Corridor estimates that the total cost to abandon and reclaim all wells drilled as of December 31, 2014, specifically two wells in Prince Edward Island, one well in the Caledonia Field, three wells in the Elgin Sub-Basin, three wells on Anticosti Island and 29 net wells in the McCully Field, is approximately $14.5 million (net present value of $8.3 million at a 2.75% discount). Corridor does not anticipate any spending relating to future abandonment and reclamation costs in the next three years.

Future liabilities for abandonment and site reclamation costs are estimated by using standard engineering design cost estimating techniques. GLJ estimates in the GLJ Reserves Report that the total cost to abandon and reclaim all wells plus related facilities in the proved plus probable case is $13.7 million ($2.4 million at a 10% discount) and $11.7 million ($3.0 million at a 10% discount) for 32 net wells under the proved reserves case. GLJ's estimate of abandonment and reclamation costs for the McCully and Caledonia Fields are included in the GLJ Reserves Report and therefore considered in their estimate of future net revenue.

Tax Horizon

The Corporation did not pay any income taxes in the year ended December 31, 2014. As at December 31, 2014, the Corporation had approximately $191 million of tax pools available to be applied against future income for tax purposes (not all tax pools can be fully utilized in any single year). Corridor’s tax pools as of December 31, 2014 are as follows:

	Amount ($M)
Canadian exploration expense	82
Canadian development expense	78
Canadian oil and gas property	4
Facilities and equipment (Class 41)	8
Transmission Pipeline (Class 1)	17
Other equipment	3
Total	**$ 191**

Based on planned capital expenditure programs and current natural gas price assumptions, the Corporation does not expect to be cash taxable for several years. On a total proved reserves basis, the GLJ Reserves Report estimates that the Corporation will never be taxable. On a proved plus probable reserves basis, the GLJ Reserves Report indicates the Corporation will be taxable in 2027. The GLJ Reserves Report does not include capital spending on projects that have not been assigned proved plus probable reserves. This additional spending could extend the Corporation's tax horizon.

The Corporation's tax horizon is dependent on, among other things, anticipated levels of production and the current commodity price forecast, anticipated capital spending, and the current tax regime. Changes in these factors from estimates used by the Corporation could result in the Corporation paying income taxes earlier or later than expected.

Costs Incurred

The following table outlines costs incurred by Corridor during the year ended December 31, 2014 for acquisitions, dispositions and capital expenditures.

Nature of Cost	**Amount** ($M)
Acquisition Costs	-
Exploration Costs	4.3
Development Costs	19.2
Total	**23.5**

Exploration and Development Activities

The 2014 capital expenditure program consisted primarily of a well re-entry and fracturing program in the McCully Field located in southern New Brunswick. The program was designed to increase natural gas production and revenues from the McCully Field and to evaluate the shale gas potential of the Elgin basin. Corridor's exploration and development activities in the near term will be focused on the Properties discussed under the heading "*Description of the Properties*" and also activities to be conducted pursuant to the Anticosti Joint Venture.

Production Estimates

The following table summarizes the volume of total gross working interest production estimated for the financial year ended December 31, 2015 using forecast prices and costs. The McCully Field accounts for all of this production.

2015 Estimated Production Forecast Prices and Costs		
	Total Proved	**Total Proved Plus Probable**
Light and Medium Oil (bblpd)	-	-
Natural Gas (mmscfpd)	7.2	7.3
Natural Gas Liquids (bblpd)	9	9
Total (boepd)	**1,219**	**1,229**

Production History and Netbacks

The average daily production volumes, prices, royalties, production costs and netbacks for Corridor's natural gas for each quarter in 2014 and the financial year ended December 31, 2014 are set out below. Corridor did not produce any crude oil and had only nominal sales of natural gas liquids in 2014. The McCully Field accounted for all of this production.

	Three months ended				Year Ended
	March 31, 2014	**June 30, 2014**	**September 30, 2014**	**December 31, 2014**	**December 31, 2014**
Natural Gas					
Average Daily Gas Production (mmscfpd)	7.6	7.2	6.6	6.9	7.1
Price ($/mscf)	$16.80	$5.19	$3.38	$8.30	$8.59
Royalties ($/mscf)	1.69	0.11	0.08	0.25	0.56
Production & Transportation Costs ($/mscf)	2.65	2.63	2.46	2.59	2.59
Netback ($/mscf)	**$12.46**	**$2.45**	**$0.84**	**$5.46**	**$5.44**

INDUSTRY CONDITIONS

Government Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government, and the Corporation's oil and gas operations are subject to various Canadian federal, provincial, territorial, and local laws and regulations. These laws and regulations may be changed in response to economic or political conditions, and regulate, among other things, land tenure and the exploration, development, production, handling, storage, transportation, and disposal of oil and gas, oil and gas by-products, and other substances and materials produced or used in connection with oil and gas operations.

More particularly, matters subject to current governmental regulation and/or pending legislative or regulatory changes include the licensing for drilling of wells, the method and ability to produce wells, surface usage, transportation of production from wells, conservation matters, the discharge or other release into the environment of wastes and other substances in connection with drilling and production activities (including fracture stimulation operations), bonds or other financial responsibility requirements to cover drilling contingencies and well plugging and abandonment costs, reports concerning the Corporation's operations, the spacing of wells, unitization and pooling of properties, and royalties and taxation. Failure to comply with the laws and regulations in effect from time to time may result in the assessment of administrative, civil, and criminal penalties, the imposition of remedial obligations, and the issuance of injunctions that could delay, limit, or prohibit certain of Corridor's operations. Corridor cannot predict the ultimate cost of compliance with these requirements or their effect on its operations.

Federal authorities do not regulate the price of oil and gas in export trade. Legislation exists, however, that regulates the quantities of oil and natural gas which may be removed from the provinces and exported from Canada in certain circumstances. At various times, regulatory agencies have imposed price controls and limitations on oil and gas production. In order to conserve supplies of oil and gas, these agencies may also restrict the rates of flow of oil and gas wells below actual production capacity. Further, a significant spill from one of the Corporation's facilities could have a material adverse effect on its results of operations, competitive position, or financial condition.

Although Corridor does not expect that these controls and regulations will affect its operations in a manner materially different than they would affect other oil and gas companies of similar size, the controls and regulations should be considered carefully by investors in the oil and gas industry. All current legislation is a matter of public record and Corridor is unable to predict what additional legislation or amendments may be enacted.

Canadian and U.S. federal, provincial and state governments are currently reviewing the responsible development of natural resources including, for example, concerns over the potential environmental impact of hydraulic fracturing operations. In furtherance of this, in 2011 the Québec Government announced a moratorium on shale gas and in March 2015, the New Brunswick Government enacted *An Act to Amend the Oil and Natural Gas Act* which creates a moratorium on all forms of hydraulic fracturing in New Brunswick.

Pricing and Marketing

Crude Oil

Producers of crude oil negotiate sales contracts directly with oil purchasers, with the result that the market determines the price of oil. Such price depends, in part, on crude oil quality, prices of competing fuels, distance to market, the value of refined products, the supply/demand balance, other contractual terms, and the world price of oil. Oil may be exported from Canada pursuant to export contracts with terms not exceeding one year in the case of light crude, and not exceeding two years in the case of heavy crude, provided that an order approving such export has been obtained from the NEB. Any oil exported under a contract of longer duration (to a maximum of 25 years) requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

Natural Gas

In Canada, the price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on natural gas quality, prices of competing natural gas and other fuels, distance to market, access to downstream transportation, length of contract term, weather conditions, the supply/demand balance and other contractual terms. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than two years or for a term of two to 20 years (in quantities not exceeding 30,000 m^3/day) are subject to an NEB order. Any natural gas exported under a contract of longer duration (to a maximum of 25 years) or in larger quantities requires the exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the NEB and the Governor in Council.

Natural Gas Liquids

The price of condensate and other natural gas liquids ("**NGLs**") sold in intraprovincial, interprovincial and international trade is determined by negotiations between buyers and sellers. Such price depends, in part, on the quality of the NGLs, prices of competing chemical stock, distance to market, access to downstream transportation, length of contract term, the supply/demand balance and other contractual terms. NGLs exported from Canada are 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 criteria prescribed by the NEB and the Government of Canada. NGLs may be exported for a term of not more than one year in respect of propane and butane and not more than two years in respect of ethane – with all exports requiring an order of the NEB.

The North American Free Trade Agreement

The North American Free Trade Agreement ("**NAFTA**") among the Canadian, United States and Mexican governments came into effect on January 1, 1994. Under NAFTA, the Canadian Government is free to determine whether exports of energy resources to the United States or Mexico should be allowed, provided that export restrictions do not: (i) reduce the proportion of energy resources exported relative to energy resources consumed domestically (with the most recent 36 month period proportion used as the basis for comparison); (ii) impose a higher export price than domestic price (subject to an exception relating to certain voluntary measures that restrict the volume of exports); and (ii) disrupt normal channels of supply.

NAFTA prohibits discriminatory border restrictions and export taxes and also prohibits the imposition of minimum or maximum export or import price requirements except with respect to the enforcement of countervailing and anti-dumping orders and undertakings. Discipline on regulators is addressed as the signatories to NAFTA agree to ensure that their regulatory bodies provide equitable implementation of regulatory measures and minimize the disruption of contractual arrangements

Land Tenure

Rights are granted to energy companies to explore for and produce oil and natural gas pursuant to leases, licenses, and permits and regulations as legislated by the respective Provincial and Federal governments. Lease terms vary in length, usually form two to five years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated. Tenure is the process of leasing and administering petroleum and natural gas rights owned by the Crown.

Companies that obtain licenses or leases to explore and develop Crown resources are subject to the relevant regulatory requirements.

Oil and natural gas 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.

Pipeline Capacity

Despite some recent oil pipeline capacity expansions, the overall pipeline capacity in Canada is tight. Notwithstanding limited pipeline capacity in Canada, Corridor projects an excess availability of capacity on the Canadian sector of the M&NP for the foreseeable future. Corridor sells all of its natural gas produced from the McCully Field and surrounding areas in southern New Brunswick pursuant to a long term agreement which includes the transportation on M&NP US. Corridor does not foresee any restricted access to the U.S. markets for the foreseeable future.

Royalties

General

For crude oil, natural gas and related production from Federal or Provincial government lands, the royalty regime is a significant factor in the profitability of the Corporation's production. Crown royalties payable in respect of crown lands are determined by governmental regulation and are typically calculated as a percentage of the value of gross production. The value of the production and the rate of royalties payable generally depend on prescribed reference prices, well productivity, geographical location, the field discovery rate and the type of product produced.

From time to time, Provincial Governments have established incentive programs for exploration and development. Such programs often provide for royalty reductions, credits and holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry.

New Brunswick

Effective April 1, 2014, the Government of New Brunswick implemented a new two-tier royalty regime for natural gas production. The new regime changes the basic royalty rate payable from the previous 10% to a royalty rate equal to the greater of a 4% basic royalty calculated on the wellhead revenues and a 2% minimum royalty calculated on gross revenues. After the Corporation, has recovered all costs and begins to make a profit, the royalty rate will increase to 25%.

Québec

At this time, Québec does not have a legislative and regulatory regime that is specific to the oil and gas industry and, accordingly, oil and gas exploration and development in Québec is subject to regulation under various laws and regulations. Currently, Québec's oil and gas resources are regulated principally pursuant to the Province's mining laws and regulations pursuant to which, among other things, royalty rates of 5 - 12.5% of the market value in fees for petroleum and natural gas apply, depending on the depth of the wellhead. The previous attempt to amend the *Mining Act*, Bill 43, was defeated in the National Assembly on October 31, 2013. On December 10, 2013, Bill 70 – *An Act to amend the Mining Act*, was given Royal Assent, which amends certain provisions of the *Mining Act*, including providing local municipalities with more decision-making powers; however, these amendments do not change any provisions relating to the royalty rates for oil and natural gas.

In March 2011, the Québec Government proposed a new shale gas royalty regime that would come into effect once a strategic environmental assessment reviewing hydraulic fracturing was completed and the legal and regulatory framework had been adapted to its conclusions. The details of the proposed shale gas royalty regime are summarized in "*A Fair and Competitive Royalty System for Responsible Shale Gas Production*" which was presented as part of the 2011-2012 budget. However, as at the date hereof such proposed regime has not yet been enacted. The proposal contemplates the following measures:

- A progressive royalty rate, calculated on a per well basis, ranging from 5% to 35% would apply for shale gas. The applicable rate will be determined according to a formula that is based on the price of natural gas (with the price component expected to take into account market price, transportation cost, processing cost and other items, with terms and conditions still to be specified) and the well's productivity (with the production component expected to be based on average daily production volume for a given month).

- The current provincial 15% tax credit for resources would be eliminated with respect to shale gas exploration and replaced by a non-refundable royalty credit for exploration, the exact terms and conditions of which will be announced at a later date but are expected to apply to an individual well and generally provide for a royalty credit of up to 15% of eligible exploration expenses, subject to a minimum royalty rate of 5% and an ability to carry forward any unused portion of the credit to a subsequent year for the same well.

- The Government intends to also introduce a gas development program, the stated objective of which would be to encourage exploration by allowing businesses to pay lower royalties in the initial development and commercialization stages of authorized projects in exchange for progressively higher royalties once they have recouped their investments. The program would provide for a minimum royalty of 2% of gross revenue starting at the time that a well is brought into production until eligible investment and operating costs plus interest have been recouped (subject to a maximum of ten years of rate relief), and increased rates thereafter. After eligible investment and operating costs plus interest have been recouped or ten years, whichever comes first, royalty rates would increase to the higher of 5% of gross revenue and (i) 15% of net revenue, until the business has achieved a 25% rate of return plus interest on its initial investment; (ii) 20% of net revenue, until the business has achieved a 100% rate of return plus interest on its initial investment; and (iii) 25% of net revenue after the business has achieved a 100% rate of return plus interest on its initial investment.

- In addition to royalty-related measures, the Government announced that municipalities would be compensated for quantifiable additional costs attributable to shale gas exploration and production and would also receive $100,000 for each shale gas well operated on its territory, to be paid over a ten-year period, in each case to be financed by industry in a manner yet to be determined.

Environmental Regulation

As an operator of oil and natural gas properties in Canada, Corridor is subject to stringent federal, provincial, territorial, and local laws and regulations relating to environmental protection as well as controlling the manner in which various substances, including wastes generated in connection with oil and gas exploration, production, and transportation operations, are released into the environment. Compliance with these laws and regulations can affect the location or size of wells and facilities, prohibit or limit the extent to which exploration and development may be allowed, and require proper abandonment of wells and restoration of properties when production ceases. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, or criminal penalties, imposition of remedial obligations, incurrence of capital or increased operating costs to comply with governmental standards, and even injunctions that limit or prohibit exploration and production activities or that constrain the disposal of substances generated by oil field operations.

Corridor currently operates or leases, and has in the past operated or leased, a number of properties that have been used for the exploration and production of oil and gas. Although Corridor utilizes and has utilized standard industry operating and disposal practices, hydrocarbons or other wastes may have been disposed of or released on or under the properties operated or leased by us or on or under other locations where such wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons or other wastes was not under Corridor's control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several or strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed of wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

Corridor believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. A recent example of this trend is the high-level of regulatory attention that the practice of hydraulic fracturing continues to receive in various jurisdictions.

New Brunswick

On February 15, 2013, the New Brunswick Government released rules, titled "*Responsible Environmental Management of Oil and Natural Gas Activities in New Brunswick*", to support New Brunswick's on-going management of oil and gas activities and to ensure that New Brunswick continues to have the tools needed to guide oil and gas exploration and extraction in an environmentally responsible manner. The rules are based on recommendations contained in *Responsible Environmental Management of Oil and Gas Activities in New Brunswick - Recommendations for Public Discussion* which was released for public comment on May 17, 2012. The requirements described in the February, 2013 rules document built upon existing regulations governing the oil and natural gas industry in New Brunswick and for the most part will be implemented as conditions to Approvals and Certificates of Determination issued under existing legislation including the *Oil and Natural Gas Act*, *Clean Environment Act*, the *Clean Air Act* and the *Clean Water Act*. Corridor is working with the New Brunswick Government and other stakeholders to ensure best practices are followed and oil and gas activities can be completed in a safe and responsible manner. The additional measures included in these rules allow for ongoing exploration and development of natural gas resources in New Brunswick. The additional requirements are extensive and in several cases incorporate industry best practices.

In addition, the Department of Energy and Mines worked with several other departments to create a blueprint for oil and gas development. The *New Brunswick Oil and Natural Gas Blueprint* was released on May 9, 2013 and focused on the following objectives: environmental responsibility; effective regulation and enforcement; community and First Nations engagement; stability of supply; and sustainable economic development. On August 7, 2014, the *New Brunswick Energy Blueprint Final Progress Report* was released, which detailed that the province was able to fulfill its commitments and complete all of the action items listed in the original report.

The Government of New Brunswick has advised, most recently on December 18, 2014, that it is committed to the development of its natural resources. However, on March 27, 2015, the New Brunswick Government enacted *An Act to Amend the Oil and Natural Gas Act* that allows government to prohibit hydraulic fracturing activity. Energy and Mines Minister Donald Arseneault stated that the moratorium will not be lifted until the following conditions are satisfied: (i) a social license for hydraulic fracturing is established; (ii) there is clear and credible information about the impacts of hydraulic fracturing on health, environment and water, so that a regulatory regime may be developed; (iii) a plan is established that mitigates the impacts on New Brunswick's public infrastructure and that addresses issues such as waste water disposal; (iv) a process is in place to respect New Brunswick's obligations under the duty to consult with First Nations; and (v) a proper royalty structure is developed to ensure that the benefits of fracturing are maximized for residents of New Brunswick. In furtherance of this, on March 24, 2015, the New Brunswick Government announced the appointment of a panel with a mandate to review and report on, within 12 months, whether the five conditions necessary to lift the New Brunswick moratorium can be met. The moratorium applies to all forms of hydraulic fracturing in New Brunswick, regardless of whether the process uses water, propane or another substance to extract natural gas from shale rock beneath the earth's surface. See "*Risk Factors - Hydraulic Fracturing*".

While it is not possible to predict the final outcome of the ongoing or proposed studies and legislation or regulation, any such restrictions will increase the costs as well as delay or halt Corridor's ability to develop its oil and gas resources in New Brunswick (McCully Field, Caledonia Field and the Elgin Sub-Basin).

Québec

In 2011, the Québec Government adopted as a policy a moratorium on all shale gas activity in Québec. On May 15, 2013, the Environment Minister tabled Bill 37, *an Act to prohibit certain shale natural gas exploration and production activities* in the Québec National Assembly. If passed unamended, Bill 37 would impose a complete ban on shale gas drilling, fracturing and injection tests in the St. Lawrence valley for five years, or until the government develops shale gas exploration regulations. In 2014, the Québec Government undertook a comprehensive strategic environmental assessment, including a full public enquiry, resulting in the issuance by the BAPE of Report 307 dated November 2014, which, generally: (i) outlines potential negative consequences from extracting natural gas from shale rock along the St. Lawrence River and (ii) states that it has not been sufficiently demonstrated that the exploration for and exploration of shale gas in the St. Lawrence lowlands with hydraulic fracturing would be advantageous to Québec because of costs and potential externalities compared to the royalties that would be collected. Neither Corridor's Old Harry prospect nor the Anticosti Joint Venture's properties is located in the St. Lawrence Valley and, accordingly, are not subject to policies in respect of the St. Lawrence lowlands.

In February 2014, the Committee for Strategic Environmental Assessment released a report detailing some of the regulatory changes which the government of Québec could implement. One option contemplated adopting an act providing for a 25-year moratorium on the shale gas industry. Another option allowed for development with controls by adopting directives, regulations or laws. The report proposed streamlining the process for obtaining permits from the government and indicated that new regulation would apply to the shale gas industry only. The new regulation would tighten existing environmental norms and companies would be expected to comply with any new directives. The report noted that any directives would likely include a reminder that compliance with the following norms is expected: (a) per the terms of section 22 of the *Environment Quality Act*, a certificate of authorization must be obtained; (b) the public must be informed and consulted; (c) the proper information and documentation supporting the request must be sent; (d) authorization must be obtained before using water and respect the applicable regulation.

On December 16, 2014, Québec Premier Philippe Couillard announced that, while developing shale gas would bring economic and financial benefit, there is not sufficient support from the population to move forward with such development. This announcement was made following the release of Report 307 dated November 2014 by BAPE. Premier Couillard subsequently clarified that he "wants the doors to stay open … or at least, that people know how to open the door" for investment in the development of Québec's oil and gas resources. See "*Risk Factors - Hydraulic Fracturing*".

The Québec Government's participation in the Anticosti Joint Venture is one component of the Government's policy to secure Québec energy independence, which policy was announced on February 20, 2014 as part of Québec's 2013-2014 Budget. In its budget speech, the Québec Government noted encouraging results from preliminary work on Anticosti Island, Gaspésie and Old Harry, and concluded that exploration work is required to ascertain Québec's oil potential. See "*Description of the Properties – Anticosti Islands, Québec – Anticosti Joint Venture*." In Québec's 2014-2015 Budget announced on June 4, 2014, the Québec Government noted that, while oil and gas exploration and development activities have raised questions and concerns among Québecers, developing Québec's oil and gas potential could represent a significant lever for economic development and should not be set aside. In this regard, it was noted that Anticosti Island and the Old Harry formation in the Gulf of St. Lawrence show promising indicators of the presence of oil.

The 2014-2015 Budget confirms the May 30, 2014 announcement by the Minister of Energy and Natural Resources and the Minister of Sustainable Development, the Environment and the Fight Against

Climate Change that the entire oil and gas sector would be subject to the Québec SEAprocess, which shall include the Anticosti SEA. The Québec SEA in respect of Anticosti Island is being carried out in tandem with the exploration work of the Anticosti Joint Venture. The Québec SEA will help assess the likely consequences of oil and gas development and estimate the economic effects of development of the oil and gas sector in Québec. Through the Québec SEA, the Québec Government intends to undertake a comprehensive review and modernization of legislation and the regulatory framework governing oil and gas exploration and development. The Anticosti SEA will study the social and economic impacts of oil and gas development on the island and identify best practices and technologies for development, as well methods to foster local economic spinoffs. Only after the completion of both the Québec SEA and the Anticosti SEA will the potential of such resources be assessed and potentially developed.

While it is not possible to predict the final outcome of the ongoing or proposed studies, policies legislation or regulation, any restrictions will increase the costs as well as delay or halt Corridor's ability to develop its oil and gas resources in Québec (Anticosti Island).

Greenhouse Gases and Industries Air Pollutants

Climate Change Regulation

Federal

Internationally, Canada is a signatory to the United Nations Framework Convention on Climate Change and previously ratified the Kyoto Protocol established thereunder, which set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide, and other GHGs. The first commitment period under the Kyoto Protocol is the five year period from 2008-2012. In December 2011, the Canadian Government announced that it would not agree to a second commitment period under the Kyoto Protocol after 2012. The Federal Government instead endorsed the Durban Platform, a broad agreement reached among the 194 countries that are party to the United Nations Framework Convention on Climate Change, during a conference held in Durban, South Africa in December 2011. The Durban Platform sets forth a process for negotiating a new climate change treaty that would create binding commitments for all major GHG emitters. The Canadian Government expressed cautious optimism that agreement on a new treaty could be reached by 2015. The Durban Platform followed the Copenhagen Accord reached in December 2009 as Government representatives met in Copenhagen, Denmark to negotiate a successor to the Kyoto Protocol. The Copenhagen Accord represents a broad political consensus and reinforces commitments to reducing GHG emissions but is not a binding international treaty. Although Canada had committed under the Copenhagen Accord to reduce its GHG emissions by 17% from 2005 levels by 2020, the target is not legally binding. The impact of Canada's withdrawal from the Kyoto Protocol on prior GHG emission reduction initiatives is uncertain.

Domestically, the Canadian Government released in 2007 its *Regulatory Framework for Air Emissions*, which was updated in March 2008 in a document entitled *Turning the Corner: Taking Action to Fight Climate Change*. Canada's previous GHG emission reduction target was 20% from 2006 levels by 2020, but on January 30, 2010 the Canadian Government announced a new GHG emission reduction target consistent with its commitment under the Copenhagen Accord to reduce GHG emissions to 17% below 2005 levels by 2020. Canada's framework proposes mandatory emissions intensity reduction obligations on a sector-by-sector basis. In December 2014 the Canadian government published "Canada's Action of Climate Change" declaring its intention to take action on climate change by reducing GHG emissions by implementing a sector-by-sector regulatory approach to protect the environment and support economic prosperity. To date, regulations for Canada's renewable fuels transportation and coal-fired electricity sectors have been developed. However, none have been developed for the oil and gas sector and regulations for the electricity sector aren't expected to take effect until 2015. In 2009, the Canadian

Government announced its commitment to work with the provincial governments to implement a North America-wide cap and trade system for GHG emissions, in cooperation with the United States, under which Canada would have its own cap-and-trade market for Canadian-specific industrial sectors that could be integrated into a North American market for carbon permits. The Government of Canada currently proposes to enter into equivalency agreements with provinces to establish a consistent regulatory regime for GHGs, but the success of any such plan is uncertain, possibly leaving overlapping levels of regulation. It is uncertain whether or when either Canadian federal GHG regulations for the oil and gas industry or an integrated North American cap-and-trade system will be implemented, or what obligations might be imposed under any such systems.

New Brunswick

The Province of New Brunswick released a Climate Change Action Plan 2007 – 2012 and has set a target of reducing its GHG emissions to 1990 levels by 2012 with an additional 10% reduction below 1990 levels by 2020 with the assistance of federal initiatives. The plan includes actions in such areas as renewable energy and energy efficiency, transportation, waste reduction and diversion, industrial sources, government leading by example, adaptation, and partnerships and communication. However, the Province of New Brunswick has not implemented GHG emission reduction legislation at this time.

Climate Change Action Plan 2014-2020 was released in April 2014. It has four goals, which are to contribute to: 1) enhanced resilience to the impacts of climate change, 2) reduced greenhouse gas emissions with sustained economic growth, 3) demonstrated leadership by the provincial government, and 4) measured and reported progress. New Brunswick aims to achieve these goals in numerous ways, such as developing an electricity efficiency plan; increasing the generation, use and promotion of renewable and low emission energy and clean technology; and requiring and harmonizing the reporting of GHG emissions in the oil and gas sector, among others.

Québec

The Province of Québec is operating under the 2013 – 2020 Climate Change Action Plan ("**Québec Climate Plan**"), which calls for a 20% reduction in GHG emissions below 1990 levels by 2020. The Québec Climate Plan includes fuel oil energy efficiency measures, measures to encourage cleaner energy alternatives and tightened fuel oil sulphur level standards. As part of the overall Plan, the Province has passed the Environmental Quality Act, which empowers the Government to set emission limits, establish reporting requirements for GHG emitters and also enables it to take part in the implementation of a cap-and-trade system.

Since January 1, 2013, large emitters in industrial and electricity sectors whose GHG emissions total 25,000 tonnes of $CO2$ are subject to a new GHG cap-and-trade system within the framework of the Western Climate Initiative ("**WCI**"). The WCI is an organization currently made up of the provinces of British Columbia, Québec, Ontario, Manitoba and the state of California designed to assist in implementing GHG emissions trading programs. Within the Québec framework, businesses are obligated to remit to the Government the emission allowances for each ton of GHG emitted. Without sufficient emission allowances, the company will be forced to purchase them on the carbon market. The objective being that a company will reduce its emissions to avoid the costs of purchasing emission allowances.

The government initially set a global GHG emission ceiling for all targeted emitters. The ceiling will gradually drop over time and achieve absolute reductions in GHG. Regulated businesses are required to cover their GHG emissions as of January 1, 2013. The government may award them a number of free emission units or “allocations” that take account of the historical level of their emissions and production. The number of free allocated units will gradually drop between 1 and 2 percent each year, beginning in 2015. Starting in 2015 the number of free units allocated per unit of production will diminish by around

1% to 2%. Businesses whose GHG emissions are higher than the number of units allocated will be required to modernize by adopting clean technologies, or else buy emission allowances (in the form of emission units, offset credits, or early reduction credits) at government auctions or on the carbon market. Businesses with GHG emissions below their allocation will be able to sell their excess carbon credits to other businesses on the carbon market.

The second cap-and-trade compliance period began January 1st, 2015 whereby business operators in Québec that distribute fuel (such as gasoline, diesel fuel, propane, natural gas and fuel oil, with some exceptions) or import it for their own consumption and whose annual GHG emissions attributed to the use of fuel distributed and consumed in Québec equal or exceed the threshold of 25,000 metric ton of CO2 equivalent will also be subject to the system. This second period ends on December 31, 2017.

In September, 2013, the California Air Resources Board, the California agency governing the state's cap-and-trade system, and the Government of Québec, signed an agreement to harmonize and integrate the cap-and-trade systems of California and Québec. The agreement requires that the cap-and-trade regimes in California and Québec mutually recognize the emission credits and allowances issued by either jurisdiction. Accordingly, GHG emitters in both California and Québec will have the ability to purchase and sell emission allowances and carbon offset credits issued by either jurisdiction. Other key terms of the agreement include the development of a common electronic registry between the jurisdictions, mutual cooperation between the jurisdictions for enforcement purposes, and the holding of joint auctions of emission allowances using harmonized procedures. The agreement was implemented through the amendment of the *Regulation respecting a cap-and-trade system for greenhouse gas emission allowances*. However, the effect that Québec's GHG emission cap-and-trade system will have on the oil and gas industry in New Brunswick is uncertain at this time.

Québec has also enacted a carbon tax on the consumption of fossil fuels in the province, under the *Regulation respecting the annual duty payable to the Green Fund.* The Québec Climate Plan also notes that the applicability of this tax will be extended to December, 2014.

RISK FACTORS

The Corporation is exposed to a number of risks inherent in exploring for, developing and producing natural gas and oil. The following list describes some of the risks that could have a material impact on the business, operations and financial condition of the Corporation. 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.

Risks Associated with Oil and Gas Exploration

There can be no assurance that commercial quantities of hydrocarbons will be recovered by Corridor in the future. Natural gas and oil exploration involves a high degree of risk and there is no assurance that expenditures made on future exploration by the Corporation will result in new discoveries of oil or natural gas in commercial quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. In addition, hazards such as unusual or unexpected formations, pressures or other conditions are involved in drilling and operating wells.

The Corporation currently has a number of specific identified exploration and development prospects. Management will continue to evaluate prospects on an ongoing basis in a manner consistent with industry standards and their past practices. The long term commercial success of the Corporation depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. No assurance can be given that the Corporation will be able to locate satisfactory properties for acquisition or participation.

Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. In particular, the Corporation is unable to predict whether or not bitumen will be encountered in the pore space within the Hiram Brook reservoir sands and to what extent the bitumen may impair the gas productivity of these reservoirs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, 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, insufficient storage or transportation capacity or other geological and mechanical conditions.

While close 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. In addition, oil and gas operations are subject to the risks of exploration, development and production of oil and natural gas properties, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, cratering, sour gas releases, fires and spills. Losses resulting from the occurrence of any of these risks could have a materially adverse effect on future results of operations, liquidity and financial condition of the Corporation.

The marketability of any oil and gas acquired or discovered will be affected by numerous factors beyond the control of the Corporation. These factors include market fluctuations, proximity and capacity of oil and gas pipelines and processing equipment and government regulations (including regulations relating to royalties, allowable production, importing and exporting of oil and gas, and environmental protection).

Substantial Capital Requirements and Financing

Substantial capital expenditures are required to finance the exploration, development and production of the Corporation's oil and natural properties. The Corporation's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. If the Corporation's revenues or reserves decline, it may have limited ability to expend 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 financial condition, results of operations or prospects.

The Corporation does not presently have sufficient financial resources to undertake by itself the exploration and development of its properties. The exploration and development of the Corporation's properties depend, therefore, on Corridor's ability to obtain additional financing through joint ventures, debt financing, equity financing or other means. Failure to obtain any financing necessary for Corridor's capital expenditure plans may result in a delay in development or production on Corridor's properties. There can be no assurance that Corridor's efforts to raise such funding or to enter into a joint venture with a partner will be successful, or achieved on terms favourable to the Corporation or its existing shareholders. The failure of Corridor to obtain additional financing or enter into a joint venture on a timely basis or on terms favourable to the Corporation could result in the loss or substantial dilution of the Corporation's interests (as existing or as proposed to be acquired) in its properties.

As at the date hereof, Corridor has a $6 million revolving short term loan with a Canadian chartered bank that matures, subject to mutual agreement to extend, on July 25, 2015 and there is currently no amount drawn on this facility. The funds under the loan are to be used by the Corporation for development and exploration activities. Variations in interest rates could result in changes in the amount required to be applied to service the amount outstanding under the loan. Based on its current exploration and development plans, Corridor does not intend to access its credit facility in 2015. On March 30, 2015, Corridor's board of directors determined not to renew its $6 million revolving credit facility

Although it is believed that the loan is sufficient, there can be no assurance that the amount will be adequate to meet the financial obligations of the Corporation or, if required, that additional funds can be obtained. The credit currently available to the Corporation is in part determined by the Corporation's borrowing base which is largely dependent on the Corporation's reserves. If, at any time during the term of the credit facility, the lender has reason to believe that the borrowing base has materially declined, the lender can recalculate the Corporation's borrowing base and could as a result, decrease the credit currently available to the Corporation. The lender has been provided with security over the assets of the Corporation. If the Corporation is unable to pay its debt service charges or otherwise commits an event of default such as bankruptcy, the lender may foreclose on or sell the Corporation's oil and gas properties and other assets.

Volatility of Natural Gas and Oil Prices

The Corporation's revenues, profitability and future growth and the carrying value of its properties are substantially dependent on prevailing prices of gas and oil. Fluctuations in natural gas or oil prices could have an adverse effect on the Corporation's operations and financial condition and the value and amount of its reserves. Prices for natural gas fluctuate in response to changes in the supply and demand for natural gas and oil, market uncertainty and a variety of additional factors beyond the Corporation's control. Natural gas prices are affected primarily by supply and demand, weather conditions and by prices of alternate sources of energy (including refined product, coal, and renewable energy initiatives). Oil prices are largely determined by international supply and demand. Factors which affect oil prices include the actions of the Organization of Petroleum Exporting Countries, world economic conditions, government regulation, political stability in the Middle East and elsewhere, the foreign supply of oil, the price of foreign imports, the availability of alternate fuel sources, transportation and infrastructure constraints and weather conditions. A substantial or extended decline in the price of natural gas or a continued low price environment for natural gas could result in a delay or cancellation of existing or future drilling, development programs or curtailment in production or could result in unutilized transportation commitments, all of which could have an adverse effect on the Corporation's revenues, profitability and cash flows.

The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon natural gas and oil prices and, in particular, natural gas prices in the New England market in northeastern United States. Prices for gas and oil are subject to large fluctuations in response to relatively minor changes in the supply of and demand for gas and oil, market uncertainty and a variety of additional factors beyond the control of the Corporation. These factors include economic conditions in the United States and Canada, consumer demand, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of gas and oil, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of gas and oil would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. In addition, a decline in the price of gas may result in Corridor having to impair, as a non-cash charge to earnings, the carrying value of its oil and gas properties. Under IFRS, the Corporation is required to perform impairment tests on oil and gas properties whenever events or changes in circumstances indicate that the carrying value of its properties may not be recoverable. To the extent a decline in the price of gas results in a reduction in the fair value of the Corporation's oil and gas properties below the carrying value, an impairment loss will be required to reduce the carrying value of the properties to their estimated fair value. The Corporation may incur impairment losses in the future, however these impairment losses could also be reversed in the future in the event of a recovery of fair value. Impairment losses and reversal of impairment losses could materially affect the Corporation's results of operations in the period incurred, adding more volatility to the Corporation's results of operations. Such impairment losses may also be viewed unfavourably by the market. No assurance can be given that prices for natural gas and oil will be sustained at levels that will enable the Corporation to operate profitably.

Volatile gas and oil prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and 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 exploration projects.

Government Regulation

The oil and natural gas industry (exploration, production, pricing, marketing and transportation) is subject to extensive controls and regulations imposed by various levels of government. See "*Industry Conditions*". Governments may regulate or intervene with respect to price, 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 natural gas and crude oil and increase the Corporation's costs, any of which may have a material adverse effect on the Corporation's intended business, financial condition and results of operations. The Corporation's operations require licenses from various governmental authorities. There can be no assurance that the Corporation will be able to obtain all necessary licenses and permits that may be required to carry out exploration and development on its properties. It is not expected that any of these controls or regulations will affect the operations of the Corporation in a manner materially different than they would affect other oil and 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. However, such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows of the Corporation.

Corridor's principal properties and oil and gas interests are located in New Brunswick and Québec. In New Brunswick, while the provincial government has stated its support of the development of natural gas resources, on March 27, 2015 it enacted *An Act to Amend the Oil and Natural Gas Act* which creates a moratorium on all forms of hydraulic fracturing in the New Brunswick, regardless of whether the process uses water, propane or another substance to extract natural gas from shale rock beneath the earth's surface.

Corridor's interests in Québec are limited to its interest in the Anticosti Joint Venture on Anticosti Island and the Old Harry prospect. In respect of Anticosti Island, on April 1, 2014, the Québec Government, through its affiliate Ressources Québec, along with Corridor, Pétrolia and M&P, established the Anticosti Joint Venture to conduct exploration activities on Anticosti Island as one component of its policy to secure Québec energy independence.

As a condition of the development of any oil and gas resources in Québec, the Québec Government has mandated the Québec SEA process in respect of the entire oil and gas sector in Québec which shall include the Anticosti SEA. The Québec SEA in respect of Anticosti Island is being carried out in tandem with the exploration work of the Anticosti Joint Venture. The Québec SEA will help assess the likely consequences of oil and gas development and estimate the economic effects of development of the oil and gas sector in Québec. Through the Québec SEA, the Québec Government intends to undertake a comprehensive review and modernization of legislation and the regulatory framework governing oil and gas exploration and development. The Anticosti SEA will study the social and economic impacts of oil and gas development on the island and identify best practices and technologies for development, as well methods to foster local economic spinoffs. Only after the completion of both the Québec SEA and the Anticosti SEA will the potential of such resources be assessed and potentially developed. See "*Description of the Properties – Anticosti Island, Québec – Anticosti Joint Venture*."

In respect of the Old Harry prospect, an offshore prospect, the issue of shale gas is not relevant. See "*Industry Conditions – Environmental Regulation*".

Environmental

All phases of the natural gas and liquids businesses are subject to environmental regulation pursuant to a variety of federal, provincial and municipal laws and regulations (collectively, "environmental legislation"). Environmental legislation imposes, among other things, restrictions, liabilities and obligations in connection with the use, generation, handling, storage, transportation, treatment and disposal of chemicals, hazardous substances and waste associated with the finding, production, transmission and storage of the Corporation's products including the hydraulic fracturing of wells, the decommissioning of facilities and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with natural gas and oil operations.

Environmental legislation also requires that wells, facility sites and other properties associated with the Corporation's operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Compliance with environmental legislation can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties and failure to comply with environmental legislation may result in the imposition of fines and penalties.

A number of federal and provincial governments have announced intentions to regulate greenhouse gases and certain air pollutants. The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect the Corporation's business, operations and financial results. Equipment that meets future emission standards may not be available on an economic basis and other compliance methods to reduce the Corporation's emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. Offset, performance or fund credits may not be available for acquisition or may not be available on an economic basis. Any failure to meet emission reduction compliance obligations may materially adversely affect Corridor's business and result in fines, penalties and the suspension of operations. There is also a risk that one or more levels of government could impose additional emissions or emissions intensity reduction requirements or taxes on emissions created by Corridor or by consumers of Corridor's products. The imposition of such measures might negatively affect Corridor's costs and prices for Corridor's products and have an adverse effect on earnings and results of operations.

Future federal legislation, including the implementation of potential international requirements enacted under Canadian law, as well as provincial emissions reduction requirements, may require the reduction of GHG or other industrial air emissions, or emissions intensity, from the Corporation's operations and facilities. Mandatory emissions reduction requirements may result in increased operating costs and capital expenditures for oil and natural gas producers. Corridor is unable to predict the impact of emissions reduction legislation on Corridor and it is possible that such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows.

Corridor believes that it is in material compliance with applicable environmental legislation and is committed to continued compliance. Corridor believes that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue and the Corporation anticipates making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws, and such legislation may have a material adverse effect on its business, financial condition, results of operations and cash flows of Corridor.

Hydraulic Fracturing

Canadian and U.S. federal, provincial and state governments are currently reviewing certain aspects of the scientific, regulatory and policy framework under which hydraulic fracturing operations are conducted. At present, most of these governments are primarily engaged in the collection, review and assessment of information regarding hydraulic fracturing and have not provided specific details with regard to any significant actual, proposed or contemplated changes to the regulatory framework. Concern has been expressed over the potential environmental impact of hydraulic fracturing operations, including harm to surface water and drinking water sources.

Corridor is unable to predict the total impact of the potential regulations upon Corridor and its operations. However, federal, provincial, and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, and adversely affect Corridor's production. Public perception of environmental risks associated with hydraulic fracturing can further increase pressure to adopt new laws, regulation or permitting requirements or lead to regulatory delays, legal proceedings and/or reputational impacts. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delay, increased operating costs, and third-party or governmental claims. They could also increase the Corporation's costs of compliance and doing business as well as delay the development of hydrocarbon (natural gas and oil) resources from shale formations, which may not be commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of natural gas and oil that the Corporation is ultimately able to produce from its reserves and resources. In the event provincial, local, or municipal legal restrictions are adopted in areas where Corridor is currently conducting, or in the future plan to conduct operations, Corridor may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. In addition, if hydraulic fracturing becomes more regulated, the Corporation's fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of natural gas and oil that the Corporation is ultimately able to produce from its reserves and resources.

The Government of New Brunswick has advised, most recently on December 18, 2014, that it is committed to the development of its natural resources. However, on March 27, 2015, the New Brunswick Government enacted *An Act to Amend the Oil and Natural Gas Act* that allows government to prohibit hydraulic fracturing activity. Energy and Mines Minister Donald Arseneault stated that the moratorium will not be lifted until the following conditions are satisfied: (i) a social license for hydraulic fracturing is established; (ii) there is clear and credible information about the impacts of hydraulic fracturing on health, environment and water, so that a regulatory regime may be developed; (iii) a plan is established that mitigates the impacts on New Brunswick's public infrastructure and that addresses issues such as waste water disposal; (iv) a process is in place to respect New Brunswick's obligations under the duty to consult with First Nations; and (v) a proper royalty structure is developed to ensure that the benefits of fracturing are maximized for residents of New Brunswick. In furtherance of this, on March 24, 2015, the New Brunswick Government announced the appointment of a panel with a mandate to review and report on, within 12 months, whether the five conditions necessary to lift the New Brunswick moratorium can be met. The moratorium on all forms of hydraulic fracturing in New Brunswick, regardless of whether the process uses water, propane or another substance to extract natural gas from shale rock beneath the earth's surface. See "*Industry Conditions - Environmental*".

On December 16, 2014, Québec Premier Philippe Couillard announced that, while developing shale gas would bring economic and financial benefit, there is not sufficient support from the population to move forward with such development. This announcement was made following the release of Report 307 dated November 2014 by BAPE which, generally: (i) outlines potential negative consequences from extracting natural gas from shale rock along the St. Lawrence River and (ii) states that it has not been sufficiently demonstrated that the exploration for and exploration of shale gas in the St. Lawrence lowlands with hydraulic fracturing would be advantageous to Québec because of costs and potential externalities compared to the royalties that would be collected. None of Corridor's or the Anticosti Joint Venture's properties are located in the St. Lawrence lowlands. See "*Risk Factors - Hydraulic Fracturing*".

While it is not possible to predict the final outcome of the ongoing or proposed policies, studies legislation and regulation, any such restrictions will increase the costs as well as delay or halt Corridor's ability to develop its oil and gas resources in New Brunswick (McCully Field, Caledonia Field and the Elgin Sub-Basin) and will affect the Anticosti Joint Venture's ability to develop its resources in Québec (Anticosti Island).

Corridor engages third parties to conduct fracturing and other well stimulation services in respect of its operations in New Brunswick.

Third Party Risk

In the normal course of its business, Corridor has entered into contractual arrangements with third parties which subject Corridor to the risk that such parties may default on their obligations. Corridor sells all of its production to large credit-worthy purchasers under normal industry payment terms.

In addition, Corridor is dependent upon the Anticosti Joint Venture partners to fund their contractual share of the planned exploration expenditures related to the Anticosti Joint Venture. If these partners do not approve or are unable to fund their share of certain expenditures or otherwise fulfill their obligations, this may result in delays or additional future costs to Corridor in respect of the development of the properties on Anticosti Island.

Dependence on Key Personnel

The success of the Corporation will be largely dependent upon the quality of its management and personnel. Loss of the services of such persons, or the inability to attract personnel of equal ability, could materially adversely affect Corridor's business operations and prospects. The Corporation has not, as yet, purchased "key man" insurance on any of its directors, officers or key employees, and has no current plans to do so.

Co-Existence with Mining Operations

PCS has a pre-existing potash mining lease granted by the Government of New Brunswick that overlays a substantial portion of the McCully Field. Applicable legislation requires that oil and gas activities not interfere with mining operations and that mining activities not interfere with oil and gas operations. The Corporation has to date succeeded in conducting its business activities in a manner that does not interfere with such mining operations. For example, several of the wells previously drilled by the Corporation have been drilled directionally to access natural gas beneath the potash mine. PCS is currently placing a new mine in operation at the McCully Field area. There can be no assurance that the Corporation's future exploration and development activities will not be adversely affected as a result of the current or future potash mining operations, including the possibility that a portion of the McCully Field may not be accessible for natural gas development.

Availability of Drilling Equipment and Access

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

Risks May Not be Insurable

The Corporation's operations are subject to the risks normally incident to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blow-outs and fires, all of which could result in personal injuries, loss of life and damage to property of Corridor and others. In accordance with customary industry practice, Corridor is not fully insured against all of these risks, nor are all such risks insurable. As referred to under "*Industry Conditions–Environmental Regulation*", environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. The Corporation expects it will be able to fully comply with all regulatory requirements in this regard.

Variations in Exchange Rates

The Corporation‘s sales of natural gas from the McCully Field are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the prices received by the Corporation. Any material increase in the value of the Canadian dollar will negatively impact the Corporation's natural gas revenues. This increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates could accordingly impact the future value of the Corporation's reserves as determined by independent evaluators. The Corporation has not engaged in any risk management activities related to the Canada/United States exchange rate. To the extent that Corridor engages in risk management activities related to the Canadian/United States exchange rates, it will be subject to credit risk associated with counterparties with which it contracts.

Expiration of Licenses and Leases

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

Reserves and Resources Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and resources, including many factors beyond the Corporation's control. The reserve, resources and associated cash flow information of the Corporation represents estimates only. In general, estimates of economically recoverable oil and natural gas reserves and of resources 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 gas and oil, royalty rates, environmental conditions, governmental and other regulatory factors and future operating costs, all of which may vary from actual results. All such estimates are to some degree speculative, and classifications of reserves and resources are only attempts to define the degree of speculation involved. For those reasons, estimates of the economically recoverable oil and natural gas reserves and resources attributable to any particular group of properties, classification of such reserves and resources based on risk of recovery and estimates of future net revenues expected therefrom prepared by different engineers, or by the same engineers at different times, may vary. The Corporation's actual production, revenues, taxes and development and operating expenditures with respect to its reserves and resources will vary from estimates thereof and such variations could be material.

Geological complexities of the McCully Field make it difficult to predict the success of future exploration and development activities in the area. These complexities include the sporadic presence of overpressured "perched" water in some portions of the reservoir, the presence of significant amounts of bitumen in some parts of the reservoir, as well as depositional and structural character of the reservoir.

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. 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, GLJ has used forecast price and cost estimates in calculating reserve quantities included in the "*Statement of Reserves and Other Oil and Gas Information*". Actual future net revenue 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 effect of inflation on costs.

Actual production and revenues derived therefrom will vary from the estimates contained in the GLJ Reserves Report with an effective date of December 31, 2014 setting forth certain information relating to certain natural gas reserves of Corridor's properties, specifically the McCully Field and the Caledonia Field in New Brunswick, and the estimated present value associated with such reserves and such variations could be material. The reserves and estimated cash flows to be derived therefrom contained in the GLJ Reserves Report and the resources estimated by Sproule in the Sproule Anticosti Resources Report, will be reduced to the extent that such activities do not achieve the level of success assumed in such reports.

Development and/or acquisition of oil and natural gas properties

The Corporation's future success depends upon its ability to develop and/or acquire additional oil and natural gas reserves that are economically recoverable. If the Corporation is unable to increase its reserves, the Corporation's business will be adversely affected because it will eventually deplete its reserves. The cost of drilling, completing and operating wells is often uncertain. The Corporation may experience unexpected cost increases, overruns, delays or cancellations of projects in their entirety as a result of numerous factors, many of which are beyond its control, including, but not limited to, weather conditions, required compliance with governmental laws and regulations, the ability to obtain stakeholder support and approvals, and shortages or delays in the delivery of equipment and services. There is the risk that no commercially productive reservoirs will be encountered, that the Corporation will not recover all or any portion of its investment, and that the Corporation's reserves, revenues and cash flow will decline. The Corporation cannot guarantee that it will be able to find and develop additional reserves at an acceptable cost or at all. The successful acquisition and development of oil and natural gas properties requires an assessment of recoverable reserves, future oil, natural gas and NGLs prices and operating and capital costs, potential environmental and other liabilities, and productivity of new wells drilled. These assessments are inexact and, if the Corporation makes them inaccurately, it might not recover the purchase price of a property from the sale of production from the property or might not recognize an acceptable return from properties it acquires.

Trading of Common Shares

The Corporation's net asset value from time to time will vary depending upon a number of factors beyond its control, including natural gas prices. The trading price of the Common Shares from time to time is determined by a number of factors, some of which are beyond the Corporation's control and such trading price may be greater or less than its net asset value.

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, and cause local flooding in the river valleys. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of drilling rigs and other heavy equipment, thereby reducing activity levels. 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.

Competition

Oil and gas exploration is intensely competitive in all its phases and involves a high degree of risk. The Corporation 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. Corridor's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of Corridor. The Corporation's ability to increase 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 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. Competition may also be presented by alternate fuel sources.

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 Corridor to deal with this growth could have a material adverse impact on its business, operations and prospects.

Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of Corridor may be subject in connection with its operations. Conflicts of interest, if any, will be subject to and governed by the procedures and remedies set forth in the ABCA.

Issuance of Debt

From time to time the Corporation may enter into transactions to acquire assets or the shares of other corporations. These transactions may be financed partially or wholly with debt, which may increase the Corporation's debt levels above industry standards. Depending on future exploration and development plans, if any, the Corporation may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. The level of the Corporation's indebtedness from time to time could impair the Corporation's ability to obtain additional financing in the future on a timely basis to take advantage of business opportunities that may arise.

Title to Properties

Prior to the drilling of a well for oil and gas, it is not uncommon for the person or Corporation acting as the operator of the well to hire a lawyer to examine the title to the spacing unit within which the proposed oil and gas well is to be drilled. Frequently, as a result of such examination, certain curative work must be done to correct deficiencies in the marketability of the title, and the curative work entails expense. The work might include obtaining affidavits of heirship or causing an estate to be administered. From time to time, the examination made by the title lawyers reveals that the oil and gas lease or leases are worthless, having been purchased in error from a person who is not the owner of the mineral interest desired. In such instances, the amount paid for such oil and gas lease or leases may be lost.

There may be title defects which affect lands comprising a portion of the Corporation's properties. The Corporation is not aware of any title defects in respect of any of the Corporation's properties.

Hedging

The Corporation may from time to time enter into agreements to receive fixed prices on its natural gas production to offset the risk of revenue losses if commodity prices decline. However, if commodity prices increase beyond the levels set in such agreements, the Corporation will not benefit from such increases and the Corporation may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements.

Corridor 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.

DIVIDENDS

The Corporation has not paid any dividends to date. Any decision to pay dividends in the future will depend upon the earnings and financial position of the Corporation and such other factors which the Board of Directors may consider appropriate in the circumstances.

DESCRIPTION OF CAPITAL STRUCTURE

Corridor is authorized to issue an unlimited number of Common Shares. As at March 30, 2015, there were 88,621,966 Common Shares issued and outstanding. The following is a summary of the rights, privileges and conditions attaching to the Common Shares. Each Common Share entitles the holder to receive notice of and to attend all meetings of the shareholders of the Corporation and to one vote at such meetings. The holders of Common Shares are, at the discretion of the Board of Directors and subject to applicable legal restrictions, entitled to receive any dividends declared by the Board of Directors. The holders of Common Shares are entitled to share equally in any distribution of the assets of the Corporation upon the liquidation, dissolution, bankruptcy or winding-up of the Corporation or other distribution of its assets among its shareholders for the purpose of winding-up its affairs.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares of Corridor are listed for trading on the TSX under the symbol "CDH". The following tables set forth the market price ranges and the aggregate volume of trading of the Common Shares on the TSX for the financial year ended December 31, 2014:

Period	High ($)	Low ($)	Volume (Common Shares)
2014			
January	1.55	1.09	3,153,157
February	2.47	1.33	4,735,981
March	2.12	1.71	1,650,024
April	2.42	1.72	2,400,062
May	2.27	1.79	1,224,853
June	2.27	1.86	1,184,036
July	2.12	1.87	694,686
August	2.05	1.87	1,253,929
September	2.01	1.45	2,643,805
October	1.59	1.25	2,483,389
November	1.46	0.99	1,302,709
December	1.18	0.84	1,358,151

PRIOR SALES

During the 12 month period ended December 31, 2014, the Corporation issued 157,833 Common Shares pursuant to the exercise of stock options in accordance with the Corporation's stock option plan. During the 12 month period ended December 31, 2014, the Corporation granted options exercisable for 900,000 Common Shares, the particulars of which are set forth in the following table:

Date of Grant	Exercise Price ($)	Number of Options [(1)] Issued
November 17, 2014	$1.24	900,000

Note:

(1) Each option entitles the holder to acquire one Common Share, on the terms and conditions set forth in the Corporation's stock option plan.

DIRECTORS AND EXECUTIVE OFFICERS

Directors and Officers

The following table sets forth the name, municipality of residence, principal occupation for the prior five years and position of each of the directors and executive officers of Corridor:

Name and Municipality of Residence	Director Since	Office or Position with Corridor	Present Occupation and Positions Held During the Last Five Years
Stephen J. Moran Calgary, Alberta	September 29, 2014	Director, President and Chief Executive Officer	President and Chief Executive Officer of Corridor since September 29, 2014. Prior thereto, Mr. Moran was President and Director of Stellavista Capital Corp (a private oil and gas company). Mr. Moran was also President, Chief Executive Officer and Director at Bellamont Exploration Ltd. (a TSXV listed junior oil and gas company) from 2006 to 2012.
Phillip R. Knoll Halifax, Nova Scotia	September 21, 2010	Director	President of Knoll Energy Inc. (a private energy consulting company), a position he has held since 2005. Prior thereto, was President and Chief Executive Officer of Corridor from October 18, 2010 to September 29, 2014.
Norman W. Miller[(2) (3)] Calgary, Alberta	March 1995	Director	Retired since October 2010. Prior thereto, was President and Chief Executive Officer of Corridor since 1995.
J. Douglas Foster[(2)] Calgary, Alberta	May 1998	Director and Chairman	President of Fostco Holdings Ltd. (private investments). Prior thereto, Partner of Bennett Jones LLP (law firm) since 1990.
Achille E. Desmarais[(1)(3)] Montréal, Québec	January 2006	Director	Independent consultant since July 2003. Prior thereto, Senior Portfolio Manager and Investment Analyst at Caisse de dépôt et placement du Québec since 1989.
Martin Fräss-Ehrfeld London, England	June 14, 2011	Director	Partner of The Children's Investment Fund Management (UK) LLP since August 2009. Prior thereto, Principal of the Blackstone Group from August 2001 to July 2009.
Robert D. Penner[(1)(2)] Calgary, Alberta	January 2006	Director	Independent consultant since April 2004. Prior thereto, senior tax partner with KPMG LLP (accounting firm).
W.C. (Mike) Seth[(1)(3)] Calgary, Alberta	January 2006	Director	Independent consultant since July 1, 2005. Prior thereto, President and Managing Director of McDaniel and Associates Ltd. (reservoir evaluation) since 1989.
Lisette F. Hachey Halifax, Nova Scotia	_	Chief Financial Officer	Chief Financial Officer of Corridor since April 2006.
Dr. Tom Martel Halifax, Nova Scotia	_	Chief Geologist	Chief Geologist since April 1998.
Paul Durling Halifax, Nova Scotia	_	Chief Geophysicist	Chief Geophysicist since June 1997

Notes:

(1) Member of the Audit Committee.
(2) Member of the Corporate Governance Committee.
(3) Member of the Reserves Committee.

The term of office of each of the directors of Corridor will expire at the next annual meeting of shareholders of Corridor.

As at March 30, 2015, the directors and executive officers of Corridor, as a group, beneficially owned or controlled or directed, directly or indirectly**,** 2,906,290 Common Shares, representing approximately 3.3% of the issued and outstanding Common Shares. In addition, directors and executive officers held options to purchase an additional 2,563,000 Common Shares, resulting in directors and executive officers holding 5.9% of the Common Shares on a fully diluted basis. The information as to Common Shares beneficially owned, not being within the knowledge of the Corporation, has been furnished by the respective individuals.

Corporate Cease Trade Orders or Bankruptcies, Penalties or Sanctions and Personal Bankruptcies

To the knowledge of Corridor, other than as described below: (a) no director or executive officer of Corridor is, as at the date hereof, or has been, within 10 years before the date of this AIF, a director, chief executive officer or chief financial officer of any company that, (i) was subject to a cease trade order, an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation that was in effect for a period of more than 30 consecutive days (an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer; or (ii) was subject to an Order that was issued after the director of executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer; (b) no director or executive officer of Corridor and no Shareholder holding a sufficient number of securities of Corridor to affect materially the control of Corridor, is, as at the date of this AIF, or has been within 10 years before the date of this AIF, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (c) no director or executive officer of Corridor and no shareholder holding a sufficient number of securities of Corridor to affect materially the control of Corridor, has, within the 10 years before the date of this AIF, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director or executive officer.

Mr. Penner had been a director of Storm Cat Energy Corporation ("**Storm Cat**") since January 2005. In November 2008, the U.S. subsidiaries of Storm Cat filed for a voluntary petition for reorganization under Chapter 11 of the United States Bankruptcy Code, which reorganization did not include Storm Cat. Storm Cat was subsequently delisted from the Toronto Stock Exchange and the NYSE Alternext U.S. LLC (formerly, the American Stock Exchange), which delistings remain in effect as of the date hereof. In April 2009, pursuant to an order of the Ontario Securities Commission, the securities of Storm Cat were cease traded for a failure to file audited annual financial statements, management's discussion and analysis and an annual information form, all for the year ended December 31, 2008. This cease trade order remains in effect as of the date hereof, subject to a partial revocation by the Ontario Securities Commission solely to permit the sale of certain Storm Cat shares, subject to certain conditions. Mr. Penner resigned as a director of Storm Cat in 2011.

Mr. Desmarais has been a director of J.A.G. Mines Ltd. ("**J.A.G. Mines**"), a junior mining company, since 2009. On May 2, 2013 the Autorité des marchés financiers (**the "AMF**") issued a cease trade order in respect of J.A.G. Mines for failing to file its annual financial statements and associated management's discussion and analysis prior to April 30, 2013 as required under National Instrument 51-102 – *Continuous Disclosure Obligations*. The AMF revoked its cease trade order on August 2, 2013.

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

Conflicts of Interest

Certain directors of the Corporation are associated with other companies, which may give rise to conflicts of interest. In accordance with the ABCA, directors who have an interest in a material contract or a material transaction, whether made or proposed, with Corridor are required, subject to certain exceptions, to disclose the nature and extent of the interest. A director required to disclose such interest shall abstain from voting on any resolution to approve the contract or transaction, except as otherwise permitted by the ABCA. In addition, each director is required to act honestly and in good faith with a view to the best interests of Corridor.

LEGAL PROCEEDINGS

The Corporation is not involved in or aware of any present or pending material legal proceedings against the Corporation involving it jointly or separately as a party.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Other than as discussed herein, there are no material interests, direct or indirect, of directors, executive officers of the Corporation or any person or company that is the direct or indirect beneficial owner of or who exercises control or direction over, 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 that has materially affected or will materially affect the Corporation.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Common Shares is Computershare Trust Company of Canada at its principal office in Calgary, Alberta and Toronto, Ontario.

MATERIAL CONTRACTS

Corridor has entered into the following material contracts in the most recently completed financial year: (i) the securityholders agreement, dated March 31, 2014, between Corridor, Ressources Québec, Pétrolia and M&P with interventions of Anticosti General Partner and Anticosti Hydrocarbons; and (ii) the amended and restated limited partnership agreement, dated March 31, 2014, between Corridor, Ressources Québec, Pétrolia, M&P and Anticosti General Partner.

INTERESTS OF EXPERTS

PricewaterhouseCoopers LLP, Chartered Accountants, are the Corporation's auditors and have audited the financial statements of the Corporation for the year ended December 31, 2014. As at the date hereof, PricewaterhouseCoopers LLP are independent in accordance with the rules of professional conduct of the Institute of Chartered Accountants of Nova Scotia.

Information relating to reserves of the Corporation set forth in the "*Statement of Reserves Data and Other Oil and Gas Information*" and certain resources set forth in the "*Resources Information*" was evaluated by GLJ, as independent qualified reserves evaluator. Information relating to certain resources of the Corporation set forth in the "*Resources Information*" was estimated by Sproule, an independent qualified reserves evaluator. As at the date hereof, the principals of GLJ and Sproule, did not hold any registered or beneficial ownership interests, directly or indirectly in the Common Shares.

AUDIT COMMITTEE

Charter of the Audit Committee

A copy of the Terms of Reference of the Audit Committee is attached at Appendix "C" hereto.

Composition of the Audit Committee

The current members of the Audit Committee are: Robert Penner, Achille Desmarais and Mike Seth, each of whom is independent and financially literate within the meaning of NI 52-110.

Relevant Education and Experience

The current members of the Audit Committee have the following relevant education and experience:

Robert Penner	Mr. Penner is a Chartered Accountant. Until his retirement in 2004, his entire career was spent in private practice with KPMG LLP focused primarily on providing advisory services on taxation and related matters.
Achille Desmarais	Mr. Desmarais is a Chartered Financial Analyst with more than 14 years of experience as a senior portfolio manager and investment analyst with the Caisse de dépôt et placement du Québec specializing in the energy sector, oil and gas, pipelines and public utilities.
Mike Seth	Mr. Seth is an independent consultant who retired as President and Managing Director of McDaniel and Associates Consultants Ltd., having been with the firm for over 37 years. He graduated with a B.Sc. in mechanical engineering from the University of British Columbia in 1966. Mr. Seth is financially literate by virtue of over 40 years of entrepreneurial business experience.

External Auditor Service Fees

PricewaterhouseCoopers LLP are Corridor's auditors for the years ended December 31, 2014 and 2013. The following table sets forth the Audit Fees, Audit – Related Fees, Tax Fees and All Other Fees billed by PricewaterhouseCoopers LLP in the financial years ended December 31, 2014 and December 31, 2013.

	2014	2013
Audit Fees(1)	$129,608	$120,332
Audit-Related Fees(2)	$15,025	–
Tax Fees(3)	$4,280	$4,240
All Other Fees(4)	–	–
Total	$148,913	$124,572

Notes:

(1) "Audit Fees" means the aggregate fees billed by the issuer's external auditor in each of the last two fiscal years for audit fees. These fees also relate to the quarterly review of financial statements.

(6) "Audit-Related Fees" means the aggregate fees billed in each of the last two fiscal years for assurance and related services by the issuer's external auditor that are reasonably related to the performance of the audit or review of the issuer's financial statements and are not reported under "Audit Fees" above.

(7) "Tax Fees" means the aggregate fees billed in each of the last two fiscal years for professional services rendered by the issuer's external auditor for tax compliance, tax advice, and tax planning.

(8) "All Other Fees" means the aggregate fees billed in each of the last two fiscal years for products and services provided by the issuer's external auditor, other than the services reported under clauses Audit-Related Fees, Tax Fees and All Other Fees above.

ADDITIONAL INFORMATION

Additional information, including director's and officer's remuneration and indebtedness, principal holders of Common Shares and Common Shares authorized for issuance under the Corporation's Stock Option Plan, is contained in the information circular of the Corporation relating to the most recent meeting of holders of Common Shares. Additional financial information is also provided in the Corporation's financial statements and management's discussion and analysis for the year ended December 31, 2014.

Additional information relating to the Corporation is available on the Corporation's website at www.corridor.ca and on the Canadian System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com and may also be obtained upon request by contacting the Chief Financial Officer of the Corporation at 301, 5475 Spring Garden Road, Halifax, Nova Scotia, B3J 3T2, phone: (902) 429-4511, facsimile: (902) 429-0209.

APPENDIX "A"

Form 51-101F2

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

To the board of directors of Corridor Resources Inc. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2014. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2014, estimated using forecast prices and costs.

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

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

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

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

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - M$)			
			Audited	Evaluated	Reviewed	**Total**
GLJ Petroleum Consultants	Corporate Summary February 18, 2015	Canada	-	112,934	-	**112,934**

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:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 18, 2015

"Originally Signed By"

Jodi L. Anhorn, M. Sc., P. Eng.
Executive Vice President & COO

APPENDIX "B"

FORM 51-101F3
REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND INFORMATION

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

An independent qualified reserve evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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 reserves data and other oil and gas information;

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

(c) the content and filing of this report.

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

"*Steve Moran*"
Steve Moran
Chief Executive Officer

"*W. C. (Mike Seth)*"
W. C. (Mike Seth)
Director

"*Norman W. Miller*"
Norman W. Miller
Director

"*Lisette F. Hachey*"
Lisette F. Hachey
Chief Financial Officer

March 30, 2015

APPENDIX "C"

CORRIDOR RESOURCES INC.

TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Policy Statement

It is the policy of Corridor Resources Inc. (the "**Corporation**") to establish and maintain an Audit Committee, to assist the Board of Directors (the "**Board**") in carrying out their oversight responsibility for the Corporation's financial reporting process. The primary objectives of the Audit Committee are to:

- help directors meet their legal duties and responsibilities;
- provide better communications between the Board and the external auditor;
- enhance the independence of the external auditor;
- increase the credibility and objectivity of financial reports; and
- strengthen the role of the Board by facilitating in-depth discussions among directors, management and the external auditor.

The Audit Committee will be provided with resources commensurate with the duties and responsibilities assigned to it by the Board including administrative support. If determined necessary by the Audit Committee, it will have the discretion to institute investigations of improprieties, or suspected improprieties within the scope of its responsibilities, including the standing authority to retain special counsel or experts.

Composition of the Committee

1) The Audit Committee shall consist of a minimum of three directors of the Corporation.

2) Members of the Audit Committee shall be appointed by the Board and may be removed by the Board in its discretion.

3) The members of the Audit Committee shall elect a Chair from among their number.

4) A majority of the members of the Audit Committee must not be officers or employees of the Corporation or an affiliate of the Corporation.

Meetings of the Committee

5) Subject to the following requirements, the Audit Committee may determine its own meeting procedures.

6) The Audit Committee shall convene a minimum of four times each year at such times and places as may be designated by the Chair of the Audit Committee and whenever a meeting is requested by the Board, a member of the Audit Committee, the auditors, or senior management of the Corporation. Scheduled meetings of the Audit Committee shall correspond with the review of the year-end and quarterly financial statements and management discussion and analysis.

7) Notice of each meeting of the Audit Committee shall be given to each member of the Audit Committee and to the auditors, who shall attend any meeting upon the request of the Audit Committee.

8) Notice of a meeting of the Audit Committee shall: (a) be in writing, (b) state the nature of the business to be transacted at the meeting in reasonable detail; (c) to the extent practicable, be accompanied by copies of documentation to be considered at the meeting; and (d) be given at least two business days prior to the time stipulated for the meeting or such shorter period as the members of the Audit Committee may permit.

9) A quorum for the transaction of business at a meeting of the Audit Committee shall consist of a majority of the members of the Audit Committee.

10) A member or members of the Audit Committee may participate in a meeting of the Audit Committee by means of such telephonic, electronic or other communication facilities, as permits all persons participating in the meeting to communicate adequately with each other. A member participating in such a meeting by any such means is deemed to be present at the meeting.

11) In the absence of the Chair of the Audit Committee, the members of the Audit Committee shall choose one of the members present to be Chair of the meeting. In addition, the members of the Audit Committee shall choose one of the persons present to be the Secretary of the meeting.

12) The Chairman of the Board, senior management of the Corporation and other parties may attend meetings of the Audit Committee; however the Audit Committee (a) shall meet with the external auditors independent of management, and (b) may meet separately with management.

13) Minutes shall be kept of all meetings of the Audit Committee and shall be signed by the Chair and the Secretary of the meeting.

14) The Audit Committee may invite such officers, directors and employees of the Corporation or affiliates as it sees fit from time to time to attend meetings of the Audit Committee and to assist thereat in the discussion of matters being considered by the Audit Committee.

15) The members of the Audit Committee shall, for the purpose of performing their duties, have the right to inspect all the books, records and operations of the Corporation and its affiliates, and to discuss such books, records and operations with the officers and employees of the Corporation and its affiliates.

Duties and Responsibilities of the Committee

16) The Audit Committee is generally responsible for managing, on behalf of shareholders of the Corporation, the relationship between the Corporation and its external auditor. This includes:

   a) identifying and monitoring the management of the principal risks that could impact the financial reporting of the Corporation;

   b) monitoring the integrity of the Corporation's financial reporting process and system of internal controls regarding financial reporting and accounting compliance;

   c) monitoring the independence and performance of the Corporation's external auditors;

d) dealing directly with the external auditors to approve external audit plans, other services (if any) and fees;

e) directly oversee the external audit process and results (in addition to items described in Section 19 below);

f) providing an avenue of communication among the external auditors, management and the Board;

g) ensuring that an effective "whistle blowing" procedure exists to permit stakeholders to express any concerns regarding accounting or financial matters to an appropriately independent individual.

17) The Audit Committee shall have the authority to:

a) inspect any and all of the books and records of the Corporation, its subsidiaries and affiliates;

b) discuss with the management of the Corporation, its subsidiaries and affiliates and senior staff of the Corporation, any affected party and the external auditors, such accounts, records and other matters as any member of the Audit Committee considers necessary and appropriate;

c) engage independent counsel and other advisors as it determines necessary to carry out its duties; and

d) to set and pay the compensation for any advisors employed by the Audit Committee.

18) The Audit Committee shall, at the earliest opportunity after each meeting, report to the Board the results of its activities and any reviews undertaken and make recommendations to the Board as deemed appropriate.

19) The Audit Committee shall:

a) review the audit plan with the Corporation's external auditors and with management;

b) discuss with management and the external auditors any proposed changes in major accounting policies or principles, the presentation and impact of significant risks and uncertainties and key estimates and judgements of management that may be material to financial reporting;

c) review with management and with the external auditors significant financial reporting issues arising during the most recent fiscal period and the resolution or proposed resolution of such issues;

d) review any problems experienced or concerns expressed by the external auditors in performing an audit, including any restrictions imposed by management or significant accounting issues on which there was a disagreement with management;

e) review with senior management the process of identifying, monitoring and reporting the principal risks affecting financial reporting;

f) review audited annual financial statements and related documents in conjunction with the report of the external auditors and obtain an explanation from management of all significant variances between comparative reporting periods;

g) consider and review with management, the internal control memorandum or management letter containing the recommendations of the external auditors and management's response, if any, including an evaluation of the adequacy and effectiveness of the internal financial controls of the Corporation and subsequent follow-up to any identified weaknesses;

h) review with financial management and the external auditors the quarterly unaudited financial statements and management discussion and analysis before release to the public;

i) before release, review and if appropriate, recommend for approval by the Board, all public disclosure documents containing audited or unaudited financial information, including any prospectuses, annual reports, annual information forms, management discussion and analysis and press releases; and

j) oversee, any of the financial affairs of the Corporation, its subsidiaries or affiliates, and, if deemed appropriate, make recommendations to the Board, external auditors or management.

20) The Audit Committee shall:

a) evaluate the independence and performance of the external auditors and annually recommend to the Board the appointment of the external auditor or the discharge of the external auditor when circumstances are warranted;

b) consider the recommendations of management in respect of the appointment of the external auditors;

c) recommend to the Board the compensation of the external auditor;

d) pre-approve all non-audit services to be provided to the Corporation or its subsidiary entities by its external auditors', or the external auditors of the Corporation's subsidiary entities;

e) approve the engagement letter for non-audit services to be provided by the external auditors or affiliates, together with estimated fees, and considering the potential impact of such services on the independence of the external auditors;

f) when there is to be a change of external auditors, review all issues and provide documentation related to the change, including the information to be included in the Notice of Change of Auditors and documentation required pursuant to National Policy 51-102 (or any successor legislation) of the Canadian Securities Administrators and the planned steps for an orderly transition period; and

g) review all reportable events, including disagreements, unresolved issues and consultations, as defined by applicable securities policies, on a routine basis, whether or not there is to be a change of external auditors.

21) The Audit Committee shall:

   a) review with management at least annually, the financing strategy and plans of the Corporation; and

   b) review all securities offering documents (including documents incorporated therein by reference) of the Corporation.

22) The Audit Committee shall review the amount and terms of any insurance to be obtained or maintained by the Corporation with respect to risks inherent in its operations and potential liabilities incurred by the directors or officers in the discharge of their duties and responsibilities.

23) The Audit Committee shall enquire into and determine the appropriate resolution of any conflict of interest in respect of audit or financial matters, which are directed to the Audit Committee by any member of the Board, a shareholder of the Corporation, the external auditors, or senior management.

24) The Audit Committee shall periodically review with management the need for an internal audit function.

25) The Audit Committee shall review the Corporation's accounting and reporting of environmental costs, liabilities and contingencies.

26) The Audit Committee shall establish and maintain procedures for:

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

   b) the confidential, anonymous submission by employees of the Corporation or concerns regarding questionable accounting or auditing matters.

27) The Audit Committee shall review the appointments of the Chief Financial Officer and any key financial managers who are involved in the financial reporting process.

28) The Audit Committee shall review and approve the Corporation's hiring policies regarding partners, employees, former partners and former employees of the present and former external auditors.

29) The Audit Committee shall review with the Corporation's legal counsel, at least on an annual basis or as otherwise appropriate, any legal matter that could have a significant impact on the Corporation's financial statements, and any enquiries received from regulators, or government agencies.

30) The Audit Committee shall assess, on an annual basis, the adequacy of this Mandate and the performance of the Audit Committee.