CORRIDOR RESOURCES INC.

ANNUAL INFORMATION FORM

For the Year Ended December 31, 2010

March 30, 2011

TABLE OF CONTENTS

GLOSSARY 2
ABBREVIATIONS AND EQUIVALENCIES 5
CONVERSION 5
FORWARD-LOOKING INFORMATION 6
CORPORATE STRUCTURE 7
GENERAL DEVELOPMENT OF THE BUSINESS 7
- General 7
- Recent Developments 10
- Three Year History 12

TRENDS 23
DESCRIPTION OF THE PROPERTIES 23
- New Brunswick Lands 24
- Gulf of St. Lawrence 27
- Anticosti Island, Québec 28
- Prince Edward Island 30
- Natural Gas Storage Licenses 30

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION 31
- Reserves Data 32

ADDITIONAL INFORMATION RELATING TO RESERVES DATA 34
- Timing of Undeveloped Reserves Assignments 34

RESOURCES INFORMATION 36
- GLJ Shale Resources Report 36
- GLJ Elgin Contingent Resources Report 37
- Oil and Gas Properties and Wells 39

INDUSTRY CONDITIONS 42
- Government Regulation 42
- Pricing and Marketing 43
- Natural Gas 43
- The North American Free Trade Agreement 43
- Land Tenure 44
- Pipeline Capacity 44
- Royalties 44
- Greenhouse Gases and Industries Air Pollutants 46

RISK FACTORS 48
- Risks Associated with Oil and Gas Exploration 48
- Substantial Capital Requirements and Financing 49
- Third Party Risk 50
- Government Regulation 50
- Environmental 50
- Prices, Markets and Marketing 51
- Dependence on Key Personnel 51
- Co-Existence with Mining Operations 51
- Availability of Drilling Equipment and Access 52
- Risks May Not be Insurable 52
- Variations in Exchange Rates 52
- Management of Growth 52
- Expiration of Licenses and Leases 52
- Reserves and Resources Estimates 53
- Seasonality 54
- Competition 54
- Conflicts of Interest 54
- Issuance of Debt 54
- Title to Properties 54
- Hedging 55
- Implementation of IFRS 55

DIVIDENDS 55
DESCRIPTION OF CAPITAL STRUCTURE 55
MARKET FOR SECURITIES 56
- Trading Price and Volume 56

DIRECTORS AND EXECUTIVE OFFICERS 56
- Directors and Officers 56
- Corporate Cease Trade Orders or Bankruptcies, Penalties or Sanctions and Personal Bankruptcies 57
- Conflicts of Interest 58

LEGAL PROCEEDINGS 58
INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS 58
TRANSFER AGENT AND REGISTRAR 59
MATERIAL CONTRACTS 59
INTERESTS OF EXPERTS 59
AUDIT COMMITTEE 59
- Charter of the Audit Committee 59
- Composition of the Audit Committee 59
- Relevant Education and Experience 59
- External Auditor Service Fees 60

ADDITIONAL INFORMATION 60

APPENDIX "A" - Form 51-101F2 – Report on Reserves Data by Independent Qualified Reserves Evaluator
APPENDIX "B" - Form 51-101F3 – Report on Management and Directors on Oil and Gas Disclosure
APPENDIX "C" - Terms of Reference of the Audit Committee

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 Corporation Act* (Alberta), as amended from time to time;

"**AIF**" means this Annual Information Form of Corridor dated March 30, 2011;

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

"**Apache Agreement**" means the farm-out and option agreement dated December 7, 2009 between Apache and Corridor", as described under "*General Development of the Business – General – Apache Farm-Out*";

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

"**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;

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

"**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 resources" is defined in the COGE Handbook as that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The term discovered resources is equivalent to discovered total petroleum-initially-in-place;

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

"**GLJ Reserves Report**" means the report prepared by GLJ dated March 5, 2011 with an effective date of December 31, 2010 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;

"**GLJ Elgin Contingent Resources Report**" means the report dated March 5, 2011 with an effective date of December 31, 2010 setting forth certain information regarding contingent resources of Corridor's interests in the Elgin Sub-Basin in New Brunswick;

"**GLJ Shale Resources Report**" means the report dated June 25, 2009 with an effective date of June 1, 2009 setting forth certain information regarding discovered resources of Corridor's interests in the Frederick Brook shale formation as described in the map in *"Description of the Properties – New Brunswick Lands – Elgin Sub-Basin"*;

"**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;

"**NBEUB**" means the New Brunswick Energy and Utilities Board;

"**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.;

"**Petrolia**" means Petrolia Inc.;

"**PetroWorth**" means PetroWorth Resources Inc.;

"**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;

"**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;

"**reserves**" refers to estimated remaining quantities of natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates;

"**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;

"**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;

"**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;

"**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
NGL or NGLs	natural gas liquids, consisting of any one or more of propane, butane and condensate	scf	standard cubic feet
WTI	West Texas Intermediate crude oil delivered at Cushing, Oklahoma	scfpd	standard cubic feet per day
bscf	billion standard cubic feet	tscf	trillion standard cubic feet
mmboe	million barrels of oil equivalent	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;
- capital budget;
- net cash flow from operations;
- capital expenditure programs;
- exploration and development plans;
- plans to drill an offshore exploration well on the Old Harry Prospect in the Gulf of St. Lawrence;
- operating expenses;
- the quantity of natural gas, oil and natural gas liquids reserves and resources;
- net present values of future net revenues from reserves;
- future development costs;
- estimates of production;
- forward sales arrangements;
- estimates of tax pools;
- timing of taxation;
- abandonment and reclamation costs;
- projections of market prices;
- 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;
- treatment under governmental regulatory regimes; and
- Apache's plans in respect of properties subject to the Apache Agreement.

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, as applicable, described 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, and the ability to add production and reserves through development and exploration activities, and the terms of agreements with third parties such as Apache, Petrolia and Repsol. 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, third party risk, government regulation, environmental, prices, markets and marketing, dependence on key personnel, co-existence with mining operations, availability of drilling equipment and access, risks may not be insurable, variations in exchange rates, management of growth, expiration of licenses and leases, reserves and resources estimates, seasonality, competition, conflicts of interest, issuance of debt, title to properties, hedging and implementation of IFRS. 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. 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 a junior resource company engaged in the exploration for and development and production of petroleum and natural gas onshore in New Brunswick, Prince Edward Island and Québec and offshore in the Gulf of St. Lawrence. The Corporation currently has natural gas reserves and production in the McCully Field near Sussex, New Brunswick and discovered crude oil reserves in the Caledonia Field near Sussex, New Brunswick in 2008. In addition, the Corporation has contingent resources and discovered resources in Elgin, New Brunswick. In December 2009, Corridor entered into a joint venture to appraise and potentially develop its significant shale gas resources in the Elgin area.

As at March 30, 2011, Corridor had 26 full time employees and one full time consultant.

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 17.8 mmscfpd (13.2 mmscfpd net) in December 2010.

The applicable leases are detailed in the "*Description of the Properties – New Brunswick Lands – McCully Field*" section of this AIF.

Caledonia Field, New Brunswick

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 frac 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 barrels of oil per day. 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. The G-36 oil discovery was named the Caledonia Field in recognition of the southern bounding basement rocks of the Caledonia highlands.

The Caledonia Field is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

The applicable leases are detailed in the "*Description of the Properties – New Brunswick Lands – Caledonia Field*" section of this AIF.

Apache Farm-out

On December 7, 2009, Corridor announced that it had entered into the Apache Agreement to appraise and potentially develop oil and natural gas resources in southern New Brunswick.

Under the terms of the Apache Agreement, Apache committed to conduct an appraisal program consisting of any combination of seismic, drilling, fracturing, testing and completing or abandoning one or more horizontal or vertical oil, gas and/or shale gas wells. The program is to be conducted over an initial 18 month period at a cost of not less than $25 million and is intended to evaluate the commercial potential of natural gas development in the Frederick Brook shale formation and light oil development at the Caledonia oil discovery. Upon completion of this appraisal program, Apache will have earned a 50% working interest in the spacing units drilled.

Upon completion of the appraisal program described above, the Apache Agreement also provides that, on or before June 1, 2011, Apache will have the option to elect to conduct a further program which shall consist of any combination of activities including seismic, drilling, fracturing, testing and completing or abandoning appraisal and development wells and the construction of a 20 kilometre natural gas pipeline from the Elgin area connecting to the Corporation's natural gas plant at the McCully Field. If the option is elected, Apache will also purchase at cost a 50% working interest in the Green Road G-41 well and spacing unit, and the purchase price will be part of the expenditure commitment for the option program. This second (optional) phase of activities is to be completed by no later than March 31, 2013 and requires the expenditure of not less than $100 million. Apache will be the operator for all activities undertaken pursuant to the Apache Agreement.

Upon completion of this program, Apache would earn a 50% working interest in approximately 116,000 net acres currently held 100% by the Corporation. Thereafter, the Corporation would be a 50% paying participant in all further activities on the farm-out lands.

Other Prospects

The Corporation holds exploration licenses and leases for several other prospects in eastern Canada, as follows:

(i) a 100% working interest in two exploration licenses (118,146 gross acres) in the Elgin Sub-Basin in southeastern New Brunswick following Corridor's acquisition of Chesapeake Energy Corporation's 50% interest in these licenses in June 2006**,** (a significant portion of Corridor's interest in these licenses is subject to the Apache Agreement);

(ii) a 100% working interest in one exploration license (44,354 gross acres) in the Havelock area located north of McCully Field;

(iii) a 100% working interest in one exploration license (44,428 gross acres) directly above the McCully Field;

(iv) a 50% working interest in three exploration leases (106,740 gross acres) located west of McCully Field;

(v) a 100% working interest in two exploration licenses issued by the Government of Québec (123,550 gross acres) in respect of the offshore Old Harry prospect located in the Laurentian Channel of the Gulf of St. Lawrence;

(vi) working interests varying from 50% to 100% in more than 30 exploration licenses (1,530,943 gross acres) covering lands across most of Anticosti Island, Québec;

(vii) a 100% working interest in two exploration licenses (264,129 gross acres) on Prince Edward Island (subject to PetroWorth's 10% interest in one license as detailed in the "*Description of the Properties – Prince Edward Island*" section of this AIF); and

(viii) A 100% working interest in exploration license 1105 (127,948 gross acres) located in the eastern end of the Old Harry prospect off the west coast of Newfoundland in the Laurentian Channel of the Gulf of St. Lawrence.

Recent Developments

Elgin Sub-Basin, New Brunswick

Subsequent to the press release dated December 6 2010, which provided an update on the Elgin shale gas appraisal program, Corridor re-tested the Green Road G-41 well to evaluate whether or not the Green Road B-41 well operations had impacted this well. The G-41 well produced gas at a constant rate of 4 mmscfpd for five days at a final flowing pressure of 1306 psi demonstrating that the frac of the B-41 well had no adverse effects on the G-41 well. Commencing on January 30, 2011, gas produced from the G-41 well was used as gas lift to assist with the clean-up of the B-41 well. The G-41 well consistently delivered the required rate of 0.5 mmscfpd to the B-41 well from the start-up of gas lift at a wellhead pressure of 2007 psi. On March 16, 2011, after 45 days of gas lift, this gas lift was stopped and, on March 17, 2011, the B-41 well was shut-in after recovering 17% of the frac fluid. The final gas rate from the B-41 well was 40 mscfpd.

The Will DeMille G-59 well was shut-in on December 8, 2010 for an extended pressure build-up, with plans to re-test the well in the second quarter of 2011.

Corridor and Apache are currently evaluating the performance to date of the Green Road B-41 and the Will DeMille G-59 horizontal wells and are considering options for the next steps. As per the Apache Agreement, the election by Apache to move to the next phase is required to be made on or before June 1, 2011. Upon review of the information and analysis performed to date, Corridor believes that there may be several reasons for the post-frac performance from the two wells drilled and fracced by Apache. The “standard” slickwater fraccing technique which was used in these wells did not generate an effective complex fracture network which is required for shale gas production, most likely due to the highly stressed formation. A different well and completion design, as evident from the results of the Green Road G-41 well, should provide more optimal frac and flow characteristics.

It is important to recognize that the evaluation of the development potential of the Elgin shale gas resource play is in its early stages.

Anticosti Island, Québec

On February 9, 2011, Corridor and Petrolia jointly announced the results of the Macasty shale core and petrophysical analyses from the Chaloupe #1 well on Anticosti Island (50% net working interest to Corridor), one of three wells drilled pursuant to a joint venture agreement with Petrolia to evaluate the oil potential of the Trenton Black River and Mingan Group formations in the east central part of Anticosti Island. The following table shows the results of the full diameter core cut in the Macasty formation of the Chaloupe well.

Core Parameters	Macasty Shale
Mineralogy (Average %)	Quartz 37, Carbonate 25, Clays 21, Other 17
Macasty Total Thickness	40 m (131 ft)
Total Matrix Porosity	3.1 to 6.3% (Average 4.9%)
Oil Saturation	35.2 to 48.3% (Average 41.9%)
Gas Saturation	1.0 to 14.7% (Average 5.0%)(1)
Water Saturation	41.5 to 63.8% (Average 53.1%)(2)
Desorbed Gas Content (Ave)	41 scf/ton
Total Organic Carbon (TOC)	1.9 to 3.87 weight% (Ave 2.97 weight%)
Maturity	0.55 (Ro %)(3)
Main Kerogen Type	Type II
Oil Gravity	35+ API

(1) Gas underestimated due to lack of pressure preservation
(2) Water saturation is overestimated as it includes water expelled from clays within the shales
(3) Reflectance suppressed by high oil saturation

These results are positive indicators for the potential of significant oil initially-in-place within the Macasty shale formation in Anticosti Island. Corridor and Petrolia engaged Schlumberger Canada to analyze the petrophysical logs using the results from the core analysis to calibrate the logs. Schlumberger Canada computed an average porosity and an average oil saturation for the Macasty formation and English Head formations in the Chaloupe #1 well. Schlumberger calculated high hydrocarbon saturations (80%) and porosities (6% effective) in the Macasty formation, with saturation and porosity declining in the overlying English Head Formation.

Corridor and Petrolia are actively evaluating their joint venture options regarding further exploration and determination of resource potential on Anticosti Island, in order to ensure that optimal shareholder value is obtained from the ongoing programs. The Anticosti exploration program is at an early stage; further work is required to determine the potential for commercially viable resource recovery, prior to proceeding to any development phase.

Gulf of St. Lawrence

Subsequent to conducting a geohazard survey in October 2010, Corridor announced on February 22, 2011 that it had submitted to C-NLOPB a Project Description for the drilling of a proposed exploration well on the Old Harry prospect within exploration license 1105 located in the Laurentian Channel of the Gulf of St. Lawrence in the Newfoundland and Labrador offshore area. This Project Description, submitted pursuant to the *Canadian Environmental Assessment Act*, commenced the official regulatory process for obtaining the necessary approvals to drill an offshore exploration well on the Old Harry prospect, which is expected to be drilled between mid-2012 and early 2014.

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 licences to explore for petroleum and natural gas previously issued by the Government of Québec in the accord area.

McCully Field, New Brunswick

In February 2011, Corridor perforated the I-47 horizontal well in the area of the failed casing patch in an attempt to uplift the production from this well. This operation was successful and the well experienced an initial three-fold increase in its gas rate. Future options are being evaluated for this well; however, options are limited by the failed casing patch.

Caledonia Field, New Brunswick

Following Corridor's announcement that Apache and Corridor had agreed to conduct tests on the South Branch G-36 oil well, a pump was run into the G-36 well and placed on test with a wax remediation treatment performed prior to the pumping operations to reduce the wax build-up in the well. After seven days of production, the pump failed and new pump equipment installed. Prior to re-opening the well, a xylene treatment was performed to clean up the wellbore and an additional wax remediation treatment was performed. Testing is ongoing.

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, 2010

McCully Field, New Brunswick

On February 19, 2010, Corridor announced that the P-47 and L-38 wells in the McCully Field appeared to be following hyperbolic decline trajectories and were currently each producing at a rate of approximately one mmscfpd. The production performances of wells in this part of the field suggests that the physical dimensions of these reservoirs may be smaller than indicated by sand thicknesses observed in well logs. One explanation could be that the observed abundance of pyrobitumen in these sands in this part of the field significantly reduces the size of the effective reservoir. Another possible explanation for the observed production performance of wells in this part of the field is the presence of petroleum wax observed in some wellheads and on tools extracted from the wells. Rapid drawdown of formation pressure during initial (high rate) production may be causing deposition of wax in the perforations and in the reservoir in the immediate vicinity of the wellbore, causing higher than normal declines in initial production rates. To evaluate this possibility, later in 2010, Corridor undertook a xylene soak / squeeze in the "E" sand of the L-38 well to attempt to remove possible wax deposition in the immediate wellbore area, which was moderately succesful. However, subsequently the productivity in the well continued to decline. The P-47 and L-38 wells will continue to be monitored for further work-over opportunities.

As a result of low natural gas prices, and the Corporation's desire to maintain a strong balance sheet with no outstanding debt, Corridor drilled only the following well in the McCully Field in 2010.

Well	**Timing of drilling Completion**	**Sands Penetrated**	**Net Pay *(metres)***	**Measured Depth *(metres)***	**Corridor Working Interest**
L-37	June 18, 2010	F&G	158	3963	100%

On June 18, 2010, Corridor announced that it had completed perforating several sand intervals within a horizontal section of the L-37 wellbore in the McCully Field. Initial efforts to flow test the well without stimulation resulted in relatively low rates of natural gas production. It appears that the L-37 well encountered greater amounts of bitumen in the reservoir sands than expected, resulting in significantly lower rates of gas production than expected. Corridor continues to evaluate the options to re-complete the well, including conducting a propane frac in the well at the next opportunity when suitable frac equipment is available in the region. The second McCully well proposed to be drilled in 2010 was deferred in response to the low natural gas prices in 2010.

During the third quarter of 2010, Corridor completed the installation of an inlet compressor aimed at increasing the production at the McCully Field in New Brunswick. The installation of the inlet compressor was successfully completed with final actual costs of $4.4 million, which was below budget by $1.6 million, and which resulted in an initial production uplift of five mmscfpd achieved early in the fourth quarter of 2010. Start-up issues required longer than planned shut-downs in late September and early October with the inlet compressor becoming fully operational in late October 2010.

In December 2010, Corridor completed perforating the B and C sands in the P-56 well which was drilled in 2001. The perforating and testing program confirmed the existence of undepleted producible gas at this location and resulted in an increase in the year-end proved and probable reserves for the McCully Field. The Corporation is evaluating the completion and tie-in options for this well which is located 2 km from Corridor's gathering system.

Caledonia Field, New Brunswick

On December 6, 2010, Corridor announced that Apache and Corridor had agreed to conduct tests on the South Branch G-36 oil well.

The Caledonia Field is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

Elgin Sub-Basin, New Brunswick

Apache completed the drilling and casing of the Green Road B-41 and the Will DeMille G-59 horizontal wells in the Frederick Brook shale play located north of Elgin, New Brunswick in the second and third quarters of 2010, respectively. The Green Road B-41 horizontal well was drilled to offset the G-41 well drilled by Corridor in 2009, and the Will DeMille G-59 horizontal well was drilled to offset the well drilled by Corridor and Columbia Natural Gas in 1999 and which flared natural gas from the Frederick Brook formation during tripping operations. Strong gas shows were encountered in the horizontal section of both wells during drilling. These gas shows occurred while using high mud weights averaging 1350 kg/m3 on the Green Road B-41 well and averaging 1,450 kg/m3 on the Will DeMille G-59 well. Five slickwater fracture stimulation procedures were completed in each of the wells with the fracs averaging 230 tonnes of propant and 3,560 cubic meters of water. The final frac in the "silty interval" of the Green Road B-41 horizontal well is approximately 630 meters from the silty interval of the Green Road G-41 vertical well. That interval in the vertical G-41 well was fraced with propane in 2009 and produced 42.4 mmscf over 185 hours, peaking at 11.7 mmscfpd with a final rate of 3.0 mmscfpd at ~ 700 psi.

After the plugs were drilled out in both horizontal wells, the Green Road B-41 well recovered 1,728 cubic meters of frac fluid (~ 10% of total) and no gas and the Will DeMille G-59 well recovered 805 cubic meters of frac fluid (~ 4% of total) and minor amounts of gas. Frac water recovery rates had declined significantly from both wells.

A significant portion of Corridor's interest in the Elgin Sub-Basin is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

Anticosti

On May 20, 2010, Corridor announced that it had entered into a joint venture agreement with Petrolia to conduct a four-well joint exploration drilling program on Anticosti Island during the summer of 2010. 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.

On September 7, 2010, Corridor reported that it had completed its 2010 oil exploration program on Anticosti Island. The following three wells were drilled in the east central part of the island. A fourth well was not drilled, as originally contemplated, due to higher than expected costs to drill on Anticosti Island.

Well	Timing of drilling Completion	Measured Depth *(metres)*	Corridor Working Interest
Jupiter	July 20, 2010	2,038	75%
Chaloupe	Aug. 25, 2010	1,639	50%
Saumon	Sep. 1, 2010	1,223	75%

The Jupiter well was a re-entry of the Corridor/Hydro-Québec Jupiter well and was drilled directionally in an attempt to encounter dolomitized and fractured carbonates in the Mingan and Romaine formations. The well encountered live oil shows in the Mingan Formation but no significant reservoir potential, and has been abandoned. The Chaloupe well was drilled with a sub-horizontal leg in the Black River section. The well encountered only minor dolomitized carbonates with no apparent reservoir development. The Saumon well was drilled with a sub-horizontal leg in the Black River section. The well encountered only minor dolomitized carbonates but had very permeable reservoir development in fractured Black River carbonates. The well flowed a total of 47 cubic meters of salt water to surface, including an initial flow of 27 cubic meters (170 barrels) in the first 45 minutes. The high apparent reservoir permeability encountered, while water bearing in this well, is encouraging for future oil exploration in the area.

The presence of live oil shows and permeable reservoir development combined with the very large number of prospects are positive factors for future oil exploration on the island. A key 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. The oil-prospective Macasty shale is present across virtually the entire island, with Corridor holding 891,906 net acres (1,530,943 gross acres) in this potential unconventional oil play.

Corridor and Petrolia have commenced activities aimed at attracting a knowledgeable shale oil player to farm-in on this play, and initial interest by several potential players has been strong, due in part to the large area covered by this potential unconventional oil play.

On March 8, 2011, Québec's Minister of Sustainable Development, Environment and Parks, announced the release by Québec's Bureau d'audiences publiques sur l'environnement ("**BAPE**"), the environmental assessment commission, of a report prepared pursuant to the *Environment Quality Act* (Québec) on sustainable development of the shale gas industry in Québec. The principal recommendations of the BAPE are (i) to conduct a strategic environmental assessment on shale gas in order to make an informed decision regarding the development of shale and in order to make the development of a shale-gas industry more socially acceptable, and (ii) to halt new exploratory shale drilling in Québec that involves fraccing.

In response to the BAPE's report, Québec's Minister of Sustainable Development, Environment and Parks announced that a committee of experts and representatives from government, municipalities and industry would be created to conduct a strategic environmental evaluation of shale gas. It is expected that the evaluation of the committee may take from 18-30 months. In addition, the Minister announced that Québec has placed a temporary ban on hydraulic fracturing (fraccing) such that no new drilling would be allowed for shale gas for a period of 30 months. Subsequently, on March 16, 2011, Québec's Minister of Natural Resources and Wildlife announced that the Québec government would no longer authorize any hydraulic fracturing operations in Québec, which moratorium is effective immediately and applies to fraccing both for gas and oil, other than for scientific purposes, during the 30 month period. A panel of experts will permit limited fracturing during this period, on the condition that the fracturing activities improve knowledge about the impact of the technique used to extract natural gas from shale rock formations.

The timing and results of Québec's planned environmental assessment are not known at this time. Corridor will seek clarification on the terms and conditions required by Québec in order to continue to undertake exploration activities involving fraccing programs on Anticosti Island.

On March 17, 2011, the Québec Minister of Finance tabled the 2011-2012 Budget, which includes the report "A Fair and Competitive Royalty System for Responsible Shale Gas Production." The Budget states that "In pursuing the objective of developing Québec’s oil and gas resources, the government will ensure that natural gas production is economically profitable, environment-friendly and safe for the public”. As part of the budget, the Québec government announced the adoption of a new royalty regime, and that it will update the laws and regulations on oil and gas in Québec.

Gulf of St. Lawrence

During the third quarter of 2010, Corridor completed a geohazard survey at a proposed drilling location on the Newfoundland and Labrador side of the Old Harry structure in the Gulf of St. Lawrence in preparation for the proposed drilling of an exploration well on the Old Harry prospect between mid-2012 and 2014. The survey was completed in four days at a cost of $1.3 million.

Other

On February 19, 2010, Corridor announced its capital and operating budget for 2010 as approved by its Board of Directors. The Corporation planned a total capital expenditure program of $28.6 million which included drilling and completing additional natural gas production wells in the McCully Field in southern New Brunswick. The budget program was designed to maintain natural gas production and revenues from the McCully Field and to undertake selective exploration activities, while allowing the Corporation to maintain a strong balance sheet with no outstanding debt. Capital expenditures for 2010 were to be based on the cash currently available and net cash flow projected to be available from projected 2010 natural gas production and sales. The total 2010 capital budget of $28.6 million net to Corridor's working interest was based on Corridor’s priorities for 2010, including: (i) drilling, testing, completing and tying in two new McCully horizontal wells in the upper part of the Hiram Brook formation; (ii) installing an inlet separator and compressor at the McCully gas plant; (iii) conducting a joint venture four-well oil exploration program on Anticosti Island (contingent upon participation of Corridor's joint venture partner); (iv) drilling an exploration core-hole at Sally's Brook located approximately 17 kilometers north of the McCully Field to test the oil and natural gas potential of the Hiram Brook and Frederick Brook formations at that location; and (v) conducting a site survey at a proposed drilling location on the Newfoundland side of the Old Harry structure in the Gulf of St. Lawrence; and undertaking gas plant maintenance and other corporate expenditures. Corridor also announced that it was commencing efforts to contract a suitable offshore drilling unit to drill an initial well on the Old Harry prospect within the next two years.

On May 10, 2010, Corridor announced Mr. Norman Miller's plans to retire at the end of September and that it had initiated a process to identify a new CEO.

In July 2010, Corridor renewed its $20 million revolving credit facility with a Canadian chartered bank. The credit facility provides that any principal amount outstanding from time to time under the credit facility will bear interest at the bank's prime rate plus 1.25% per annum, with interest payable monthly. This credit facility expires on July 30, 2011.

In response to lower natural gas sales prices, lower forecasted natural gas production and a weaker U.S. dollar, during 2010 Corridor revised its budget to decrease its previously estimated net average production for 2010 from 17.5 mmscfpd to 13.3 mmscfpd due primarily to the lower than estimated production from the McCully L-37 well and the decision not to drill a second McCully well in 2010. Corridor also decreased its previously estimated cash flow from operations from $25.5 million to $12.5 million and decreased its 2010 capital budget from $28.6 million to $22.5 million.

The Board appointed Mr. Phillip R. Knoll as a director of Corridor effective September 21, 2010 and as President and Chief Executive Officer effective October 18, 2010, concurrent with the resignation of Norman Miller, Corridor’s founding CEO. Mr. Miller agreed to continue to act as a director of Corridor, but resigned as CEO to spend more time with his family.

Financial Year Ended December 31, 2009

Drilling – McCully Field, New Brunswick

The Corporation drilled the following wells in the McCully Field in 2009:

Well	Timing of drilling Completion	Sands Penetrated	Net Pay *(metres)*	Measured Depth *(metres)*	Corridor Working Interest
C-29	Mar. 2009	C,D,E&F	51	3,390	100%
P-47	Mar. 2009	D,E,F&G	93	3,178	100%
L-38	May 2009	D,E,F&G	55	3,133	100%

In May 2009, Corridor suspended drilling operations at the McCully Field for the remainder of 2009 to maintain a strong cash-positive balance sheet as a result of lower than forecast natural gas prices.

Well Stimulation and Production Test Results – McCully Field, New Brunswick

On May 5, 2009, Corridor announced that methanol and water had been the significant components of the frac fluids employed in its completion programs of the past two years. High concentrations of methanol served to reduce the surface tension effects of the frac fluids and to prevent hydrates from forming during testing and production operations. However, evidence indicates that chemical interactions between methanol and certain components of the formation appear to have caused down-hole scaling and deposition of minerals, including gypsum, within the well-bore. These deposits appear to be impairing production performance of at least some of these wells, accentuated by the unusually low temperatures and high pressures of the McCully reservoirs. Observations of scale deposits on instruments retrieved from the bottom of some wells indicate that these deposits may be reducing the flow capacity of these wells and causing greater declines in production rates than were expected. Corridor and its consultants designed a work-over program conducted in the summer of 2009, commencing with the J-38 well, aimed at removing these down-hole scale deposits. While the work-over program was successful in the J-38 well, Corridor is evaluating more cost effective treatments for other McCully wells if impacted by this issue.

On August 12, 2009, Corridor announced a pressure failure in the casing patch installed earlier that year in the McCully I-47 well resulting in only one frac being successfully completed in the well and lower than estimated natural gas production. On September 9, 2009, Corridor announced that the McCully I-47 well had been connected to the gathering facilities and was producing to the gas plant at a rate of approximately 0.45 mmscfpd.

On September 9, 2009, Corridor reported the initial results of fracturing and flow-testing of the McCully L-38 and P-47 wells located in the northeastern segment of the McCully Field. The wells were fractured with liquid propane followed by flowback and initial flow test operations. This was the first time that fracturing with propane was conducted in the McCully Field, as completion operations in previous years had mainly used combinations of water and methanol as the frac fluid. Corridor redesigned its approach to fracturing new wells in the McCully Field to use propane, which is a proponent of natural gas, on the basis that it would minimize formation damage and be more readily recoverable on flowback than water and methanol. Based on the initial results, Corridor estimated the initial production capacity of the McCully P-47 well to be 9 to 10 mmscfpd and the McCully L-38 well to be 12 to 13 mmscfpd at the McCully gathering system line pressure (3,500 kPa or 500 psi). These positive results were attributed partially to reservoir characteristics and partially to the successful application of propane as the frac fluid. On October 15, 2009, Corridor reported it was continuing to flow test the McCully L-38 and P-47 wells and that the wells were producing in-line to the gas plant at constrained rates in the range of 5 to 6 mmscfpd each to assess their respective longer term flow performances. Subsequently, Corridor reported that both the P-47 well and the L-38 well could decline at somewhat more rapid rates than normal for most McCully wells.

Caledonia Field, New Brunswick

In January 2009, Corridor announced its 2009 capital program which included plans to drill an initial step-out well to follow up on the South Branch G-36 oil discovery well and a further exploration well located approximately 4 kilometres southeast of the South Branch G-36 oil discovery well designed to evaluate the oil and/or natural gas potential of sands in the upper Hiram Brook formation and the shale gas potential of the Frederick Brook formation. Subsequently, Corridor deferred this plan pending more study of data from the 3-D seismic and to preserve capital.

In May 2009, Corridor discontinued the pump testing of the South Branch G-36 oil well and shut-in the well for a pressure build-up. The well had produced 45° API oil on pump at a maximum rate of 45 barrels per day before declining to a final rate of approximately 5 barrels per day. Factors that may have contributed to these results are the apparent partial failure of the water/methanol frac in the G-36 well, the presence of oil/water emulsions and wax in the recovered fluids and possibly poorer than expected reservoir quality. The 3-D seismic acquired by Corridor in the fall of 2008 shows extensive potential for numerous additional wells to follow up on this light oil discovery.

The Caledonia Field is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

Elgin Sub-Basin, New Brunswick

In January 2009, Corridor announced that the Green Road G-41 exploration well (100% Corridor) had been drilled to a total depth of 2422 metres, logs had been run and the well had been cased in preparation for fracturing operations. The well encountered relatively thin (17 metres in total) hydrocarbon bearing sands in the Hiram Brook formation based on logs, and penetrated 785 metres of Frederick Brook gassy shale, siltstone and minor (11 net metres) sandstone prior to reaching total depth in the lower Frederick Brook formation. Initial results for the Frederick Brook formation appeared to be very promising. Of particular interest was a massive, predominantly siltstone interval between 1753 and 1906 metres that is friable in nature and which exhibited strong shows of natural gas during drilling. In addition, approximately 10 metres of sheared, fractured black shale was recovered as conventional core cut from a deeper interval (1919 to 1929 metres), and numerous sidewall cores were collected for unconventional shale gas analysis. The results of this analysis, as well as other well information, was subsequently used by GLJ to generate the GLJ Shale Resources Report.

In November 2009, Corridor conducted propane fracs and completed initial clean-up flow of two intervals in the upper part of the Frederick Brook formation at the Green Road G-41 (vertical) well. 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 in the Frederick Brook formation that had been fractured with propane at the vertical Green Road G-41 well. Following the initial comingled 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.

A significant portion of Corridor's interest in the Elgin Sub-Basin is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

Gulf of St. Lawrence

The Québec government announced in its April 2009 budget that it would be undertaking a strategic environmental assessment program in the Gulf of St. Lawrence to prepare the path for offshore oil and natural gas exploration and development. The time table set by the government indicated this assessment would be completed over a two and one-half year period.

Other

On January 14, 2009, Corridor announced its capital and operating budget for 2009, pursuant to which it planned a total capital expenditure program of $59.9 million, primarily related to drilling and completing additional natural gas production wells in its McCully Field in southern New Brunswick. The budget program was designed to increase natural gas production and revenues from the McCully Field and evaluate the oil and shale gas potential of the surrounding basin, while allowing the Corporation to maintain a strong balance sheet with no outstanding debt.

Corridor revised its 2009 budget to reflect lower natural gas sales prices, lower forecasted natural gas production level and a weaker U.S. dollar. Corridor decreased its previously estimated net average production for 2009 from 22 mmscfpd to 17 mmscfpd primarily reflecting the production problems encountered in the McCully Field with the McCully N-66 well and I-47 wells. Corridor also decreased its previously estimated cash flow from operations from $58 million to $30.5 million and decreased its 2009 capital budget from $59.9 million to $40 million.

On July 31, 2009, Corridor secured a new $20 million revolving credit facility with a Canadian chartered bank, which facility replaced its previous $40 million revolving credit facility with a Canadian chartered bank. Corridor determined that a credit amount of $20 million was sufficient based on the Company's then current plans and the lower credit facility resulted in cost savings relating to commitment and stand-by fees otherwise payable to the bank.

Financial Year Ended December 31, 2008

Drilling – McCully Field, New Brunswick

In January 2008, Corridor terminated under-balanced drilling operations at the McCully E-67 well in favour of completing the drilling of the well using a conventional over-balanced drilling fluid. While drilling with an under-balanced drilling fluid, the E-67 well encountered a section of highly fractured and faulted shale in the upper 150 metres of the Frederick Brook formation at a depth of approximately 2630 metres. Following two failed attempts to drill through the highly fractured shale section, Corridor concluded that the instability of the well-bore would prevent further deepening of the well using an under-balanced drilling process.

In March 2008, the McCully E-67 well was deepened using over-balanced drilling fluid to a total depth of 4130 metres, the deepest well drilled to date in New Brunswick, encountering 18 metres of indicated net gas pay in the "B" sand of the Hiram Brook formation and over 1160 metres of Frederick Brook shale. However, the well failed to encounter sands in the Dawson Settlement formation at this location and reached total depth in "red beds" consisting primarily of siltstone and shale. Significant shows of natural gas were encountered while penetrating the Hiram Brook "B" sand and in extensive naturally fractured shale intervals within the Frederick Brook formation. The Hiram Brook "B" sand was cased for fracturing and completion at a future date.

The Corporation drilled the following wells in the McCully Field in 2008:

Well	Timing of drilling Completion	Sands Penetrated	Net Pay *(metres)*	Measured Depth *(metres)*	Corridor Working Interest
E-67	Mar. 2008	B	18	4,130	50%
K-48	Mar. 2008	B,C&D	20	2,867	100%
J-47	Apr. 2008	D,E,F&G	84.5	3,527	100%
C-48	May 2008	C,D,E&MB	49.5	2,528	100%
C-57	Jun. 2008	A,B,C,D&E	36.4	2,916	50%
P-67	Jul. 2008	A&B	47.5	2,791	50%
I-47	Aug. 2008	E	Horizontal	3,693	100%
N-66	Oct. 2008	A&B	Horizontal	3,510	50%

Well Stimulation and Production Test Results – McCully Field, New Brunswick

On March 28, 2008, Corridor announced that production of the McCully J-38 well had been initiated to Corridor's gas plant at a rate of approximately three mmscfpd. A production log run in the well during testing operations indicated that a high percentage of the bitumen laden gas sands in this well were contributing to the production stream.

Corridor conducted its 2008 fracture stimulation, completion and testing program at the McCully wells during Q3 and Q4 2008. The following table provides a summary of intervals fractured and completed as well as final flow test results:

Well	Sands Completed	Test Date	Flow Duration *(hours)*	Choke Size *(mm)*[(3)]	Tested Rate *(mmscfpd)*	Tubing Pressure *(psi)*	Transient Productivity Index [(1)] *(scfpd/psi2 after 4 days)*	Projected Rate @ FTHP[(2)]= 1000 psi *(mmscfpd)*
C-48	C,D,E&MB	Oct 2008	93	6.75	1.4	630	0.160	1.4
C-57	A,B,C,D&E	Oct 2008	96	In-line	1.8	753	0.221	1.9
I-47	E	NA	-	-	-	-	-	-
J-47	D,E,F&G	Oct 2008	65	In-line	6.8	713	0.789	7.1
K-48	B,C&D	Oct 2008	96	13	0.5	586	0.071	0.5
N-66	A	Oct 2008	Frac flowback	Frac flowback	2.7	179	Frac flowback	-
P-67	A&B	Oct 2008	96	In-line	4.0	1473	0.532	5.1
Total					**17.2**			**16.0**

Notes:

(1) Transient Productivity Index ("**PI**") is a basic reservoir performance factor that enables wells to be compared on an equivalent basis. Transient PIs are a function of time (as well as reservoir and fracture properties) so all calculations were made assuming the same time (4 days). For current and future comparative purposes, Transient PIs are calculated (or estimated) after 96 hours of flow. Rate is the forecasted rate after 96 hours of flow at the assumed tubing head flowing pressure. Transient PIs will continue to decline until steady state flow is achieved, which could take more than one year for low permeability reservoirs.

(2) "**FTHP**" means Flowing Tubing Head Pressure.

(3) "**mm**" means millimetres.

In December 2008, Corridor announced that production from the J-47 well was stabilizing at a rate of approximately three mmscfpd at a flowing wellhead pressure of 600 psi, 34 days after coming on-stream.

The two horizontal wells drilled in 2008, I-47 and N-66, encountered problems which prevented them from being completed and achieving their production potential prior to the end of 2008. At I-47, initial attempts to install and pressure test a casing patch to correct a leak in the well took longer than expected as a result of a failure of a down-hole hydraulic setting tool; replacement tools were mobilized and the casing patch installed in early 2009. The N-66 well was fractured into an over-pressured 'perched' water zone underlying the "heel" of the horizontal part of the wellbore. Corridor believes that formation water accumulated in the heel, and is restricting the flow of natural gas to the surface. Corridor installed a sliding sleeve in the production tubing in an unsuccessful attempt to allow gas flow to by-pass the water restriction. A subsequent attempt to pump the water out of the well resulted in gas flow of approximately 100 mscfpd. The N-66 well was subsequently tied in to the midstream facilities and subsequently placed on production under natural flow conditions at a similar gas flow rate.

Caledonia Field, New Brunswick

On October 28, 2008, Corridor announced the drilling of the South Branch G-36 exploration well to a depth of approximately 2642 metres in the Frederick Brook shale. The well encountered a thick Hiram Brook formation within the interval 1380 metres to 2194 metres containing 33 metres of net natural gas bearing sands and a further 46 metres of net reservoir sand with unknown fluid content, based on well logs and using a 4% porosity cut-off.

On December 3, 2008, Corridor announced a potentially significant oil discovery at the South Branch G-36 well. The G-36 oil discovery was named the Caledonia Field in recognition of the southern bounding basement rocks of the Caledonia highlands. The G-36 well was cased and two frac stimulation treatments were carried out over two intervals within the Hiram Brook formation. The first frac, conducted over 10 metres of potentially gas bearing sands within the depth interval 1757 - 1840.5 metres in the lower Hiram Brook formation, yielded a show of oil and no measurable amounts of gas and is considered to be tight. The second frac was conducted in a 38 metre thick sand within the depth interval 1574 – 1612 metres in the upper Hiram Brook formation. The frac placed 30 tonnes of proppant prior to being prematurely concluded due to a frozen water line which may have reduced the effectiveness of the frac. Following 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 barrels of oil per day. The well was initially 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. An additional 31 metres of potential oil or gas pay (included in the 46 metres of net reservoir sand with unknown fluid content previously reported) in the upper Hiram Brook formation have not as yet been completed in this well.

In December 2008, Corridor completed the initial processing of a $2.5 million 3-D seismic program surrounding the South Branch G-36 to assist in mapping the Caledonia oil field and to identify the most favourable locations for drilling follow-up wells to determine the potential size of the oilfield.

Elgin Sub-Basin, New Brunswick

On June 2, 2008, Corridor announced plans to accelerate the appraisal and economic assessment of the prospective Frederick Brook shale development in the Elgin area of southern New Brunswick. Corridor's Elgin licences (excluding Corridor licences in the general McCully area) cover an area of 118,146 acres where the Frederick Brook shale is known to be very thick and covers an extensive area.

In December 2008, Corridor completed the drilling and logging of a core hole that cored the entire (thinner) Frederick Brook shale interval at the Mapleton N-11 well, located approximately 8 kilometres northeast of Elgin, New Brunswick. The well reached a total depth of 810 metres in red beds (basement rocks) prior to logging and was subsequently abandoned.

Midstream

Corridor announced on July 9, 2008 that it had pre-sold a portion of its natural gas production for the winter season (November 1, 2008 through March 31, 2009), with the forward sales priced at Dracut, Massachusetts and consisting of 5,000 mmbtupd at a price of US$14.40/mmbtu and an additional 5,000 mmbtupd at a price of US$15.49/mmbtu.

On June 16, 2008, Corridor announced that it had entered into a long term agreement to sell all of its natural gas produced from the McCully Field and surrounding areas in southern New Brunswick. This agreement with Repsol Energy Canada Ltd., which became effective on April 1, 2009, 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 Dracut, Massachusetts less pipeline transportation costs on M&NP).

PEI

In July 2008, Corridor entered into a revised agreement with PetroWorth regarding natural gas exploration activities on Prince Edward Island, whereby PetroWorth agreed to finance 100% of the costs of fracturing and testing the initial two zones in the Green Gables #3 well in early August 2008 to a maximum cost of $2 million to earn a 10% working interest in Corridor's Green Gables licence 04-03. In addition, under the agreement, Corridor had the option (until September 5, 2008) to elect to locate and drill (prior to July 31, 2009) a total of two exploration wells (including at least one frac in each well) on lands comprising PetroWorth licences 03-01, 03-02, 04-05, 04-06 and 04-07 to earn a 50% working interest in these licences. Corridor and PetroWorth also agreed that each shall have the right to back into a 50% working interest in any licence acquired by the other party on Prince Edward Island during the next five years. This agreement revised the previous agreement between Corridor and PetroWorth announced on May 11, 2007.

In August 2008, Corridor completed the fracturing of two intervals in the Green Gables #3 well and suspended operations there to evaluate results. Corridor reported that it had recovered less than 50% of the frac fluids and small amounts of natural gas during these testing operations. Corridor also elected not to exercise its option to drill a total of two exploration wells on lands comprising PetroWorth licences 03-01, 03-02, 04-05, 04-06 and 04-07 to earn a 50% working interest in these licences.

Corridor ran production tubing in the well to facilitate efforts to remove additional volumes of unrecovered frac fluids from the wellbore and to monitor gas influx over the months ahead.

Other

Effective January 18, 2008, Paul J. Hopkins retired from his positions of Vice-President and a director of the Corporation.

On June 20, 2008, Corridor issued 3,800,000 Common Shares at a price of $10.60 per share and 1,150,000 Common Shares issued on a "flow-through" basis at a price of $13.00 per share for aggregate gross proceeds of approximately $55 million pursuant to a bought deal financing. The net proceeds from the offering were used to fund the acceleration of the appraisal and economic assessment of the prospective Frederick Brook shale development in the Elgin area of southern New Brunswick, to fund a program to accelerate production at the McCully Field and for working capital.

In June 2008, Corridor renewed its $40 million revolving short term credit facility with a Canadian chartered bank.

On April 11, 2008, Corridor announced that it was conducting a non-binding open season commencing on April 15, 2008 and closing on May 30, 2008 to solicit interest from existing and future shippers on the M&NP system for storage services from Corridor's proposed Salt Springs Storage facility near Sussex, New Brunswick. On June 16, 2008, Corridor announced that it had received encouraging responses to its open season request for interest in natural gas. Corridor determined that the results indicated there was sufficient interest to justify the initial development of at least one storage cavern with working gas capacity of 3.0 to 3.5 bscf of natural gas with sufficient injection/withdrawal capacity to justify a pipeline connection between the storage cavern and Corridor's existing pipeline system at the McCully Field as well as the necessary upgrading of Corridor's pipeline connection with the M&NP.

On November 11, 2008, Corridor revised its 2008 capital program from $90.8 million to $81.6 million to preserve capital during the economic downturn.

TRENDS

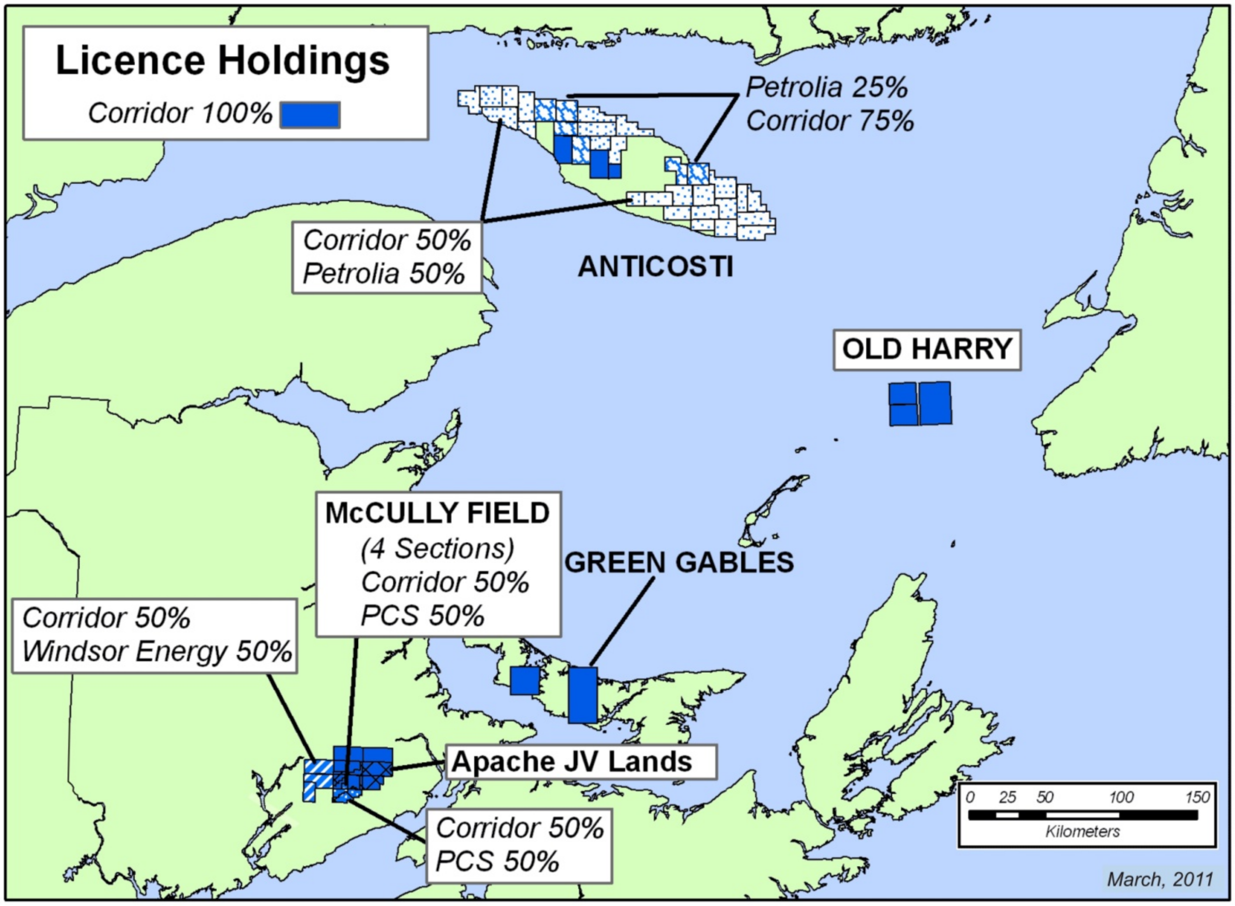
There are a number of trends that appear to be developing, which may have both long and short-term effects on the industry and the competitive positioning of the Corporation. The discussion of these trends and their potential impact constitute forward-looking statements. Refer to "*Forward-Looking Statements*" and "*Risk Factors*".

There is a continued trend in the oil and gas industry relating to volatility of commodity prices in addition to a general decline in the price of natural gas. With excess supply and reduced demand for natural gas, the market is experiencing a great deal of elasticity in pricing due to a number of factors, including drilling activity, production declines, storage levels, fuel switching, the potential impact of shale gas and North American demand. 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.

As a result of the volatility in oil and gas prices, oil and gas exploration and development companies are reducing their capital budgets and development programs.

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, 2011.



New Brunswick Lands

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 held jointly with PCS). 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 - Recent Developments*" and "*General Development of the Business – Three Year History – Financial Year Ended December 31, 2010*".

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.

In 2009, pursuant to the Gas Purchase and Sale Agreement, PCS purchased from Corridor, effective June 28, 2007, its 50% interest in the gas plant and pipeline facilities that transports gas to the PCS potash mill for proceeds of $2.3 million.

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 (40,930 acres). One oil well has been drilled in the Caledonia Field (South Branch G-36 well).

- 50% working interest in ONG Lease 09-01.

The Caledonia Field is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

For additional information regarding development activities in the Caledonia Field, see "*General Development of the Business - Recent Developments*" and "*General Development of the Business – Three Year History – Financial Year Ended December 31, 2010*".

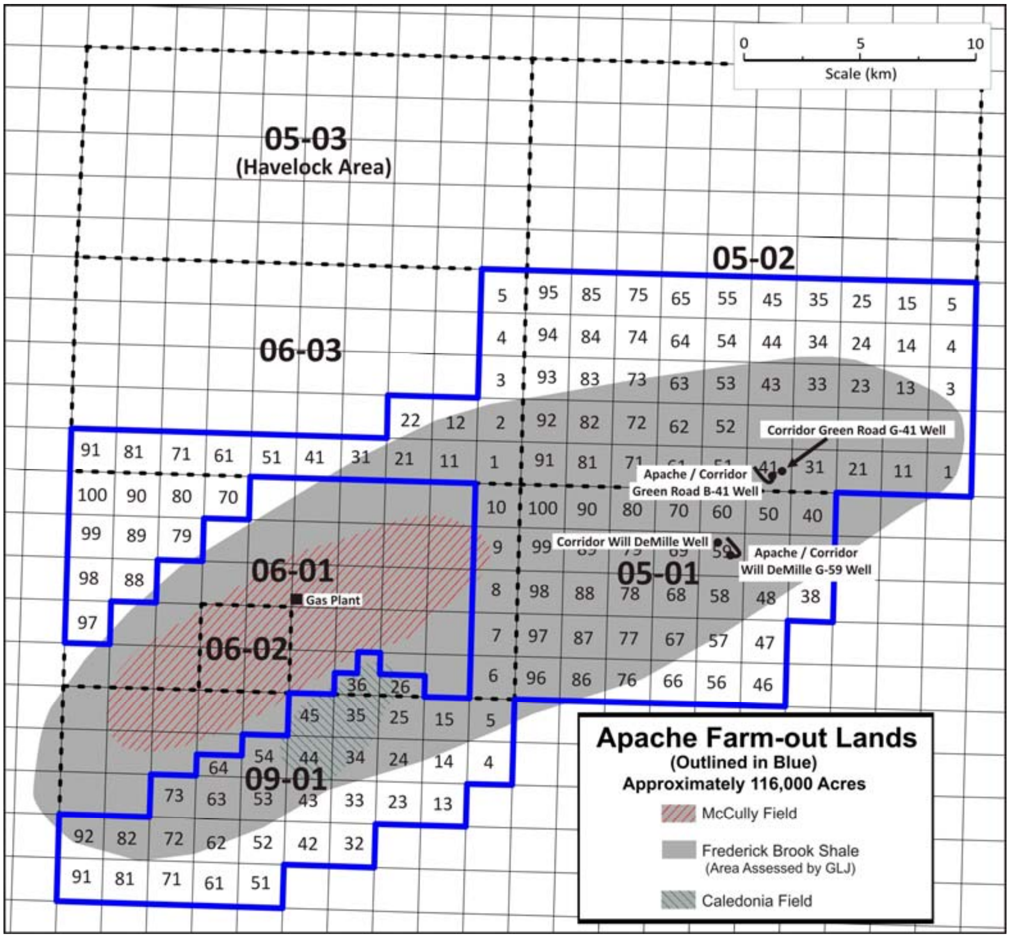
Elgin Sub-Basin

Corridor has a 100% working interest in two exploration leases (ONG Lease 05-01 and ONG Lease 05-02) covering 118,146 gross acres in the Moncton basin in southeastern New Brunswick and where Corridor drilled the Wille deMille well in 1999. In June 2006, Corridor acquired a 50% working interest in these two leases from Chesapeake Energy Corporation, which had previously acquired these interests when it acquired Columbia Natural Resources Canada, Ltd. in 2005. During the fall of 2006, Corridor acquired 56 km of 2D seismic data across a portion of the Elgin leases.

A significant portion of Corridor's interest in the Elgin Sub-Basin is subject to the Apache Agreement. See "*General Development of the Business – General – Apache Farm-Out*" in this AIF.

For additional information regarding development activities in the Elgin Sub-Basin, see "*General Development of the Business - Recent Developments*" and "*General Development of the Business – Three Year History – Financial Year Ended December 31, 2010*".

The following map highlights Corridor's interest in New Brunswick (and identifies certain of Corridor's leases), the area covered by the Apache Agreement and the areas subject to the GLJ Reserves Report, GLJ Shale Resources Report and GLJ Elgin Contingent Resources Report:



Notes:

- *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)*
- *Corridor's resources as evaluated in the GLJ Shale Resources Report are located in the Frederick Brook Shale (covering in large part ONG leases 06-01, 06-02, 05-01 and 09-01 and partly ONG leases 06-03 and 05-02)*
- *Corridor's resources as evaluated in the GLJ Elgin Contingent Resources Report are located in the vicinity of the Green Road G-41 well (covering a small part of ONG leases 05-01 and 05-02 and less than 8% of the total Frederick Brook rock volume and total shale gas potential)*

McCully North

Corridor has a 100% working interest in one exploration lease (ONG Lease 06-03) covering 44,428 acres located directly above the McCully Field. Corridor is considering a limited seismic program in this area subject to the result of discussions on the renewal of this license and to the finalization of the Corporation's 2011 capital budget.

Havelock Area

Corridor holds a 100% working interest in ONG Lease 05-03 (44,354 acres) located to the north of the McCully Field. Corridor is considering drilling a core hole in the Sally's Brook area in 2011 subject to the result of discussions on the renewal of this license and to the finalization of the Corporation's 2011 capital budget.

Corridor / Windsor Energy Lands

Corridor has a 50% ownership in three exploration leases (ONG 09-02, ONG 09-03 and ONG 09-04) located to the west of the McCully Field, covering an area of 106,740 gross acres (53,370 net acres). On December 22, 2000, Globex Resources Ltd. ("Globex") (subsequently acquired by Innova Exploration Ltd. in May 2005 and then by Crescent Point Energy Trust ("Crescent Point") in October 2007) entered into a farm-out agreement with Corridor in respect of this property, conditional upon the issuance of such licenses to Corridor. Under the terms of the farm-out agreement, Globex earned a 50% working interest in these lands. Crescent Point sold its 50% ownership in the three exploration licenses to Windsor Energy Inc. in 2009.

Gulf of St. Lawrence

Québec

The Corporation holds Québec exploration licenses covering 123,550 gross acres (123,550 net acres) over most of the Old Harry prospect, lying in 1,500 feet of water in the Laurentian Channel in Québec. The prospect has simple 4-way closure covering an area of more than 20,000 hectares, 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.

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 licences to explore for petroleum and natural gas previously issued by the Government of Québec in the accord area.

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 farmin opportunity on the same terms as are ultimately negotiated with an operating partner. Hydro-Québec also gained access to the seismic covering the Old Harry and Cape Ray prospects.

In 2009, the Québec government announced in its April budget that it would be undertaking a strategic environmental assessment program in the Gulf of St. Lawrence to prepare the path for offshore oil and natural gas exploration and development. The time table set out by the government indicates this assessment would be completed over a two and one-half year period. Consequently, the earliest time that a permit could be issued by the Canadian and Québec governments to drill an offshore exploration well in the Québec sector of the Gulf would be 2012.

Newfoundland and Labrador

On December 3, 2007, the C-NLOPB announced that Corridor was the successful bidder for a 51,780 hectare 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 carries a minimum work commitment of $1,521,000 to be conducted over a five year initial term. Acquisition of this licence is part of Corridor's long-term efforts to open up hydrocarbon exploration offshore in the 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 announced that it had submitted to the C-NLOPB a Project Description for the drilling of an exploration well on the Old Harry prospect within Exploration License 1105 located in the Gulf of St. Lawrence in the Newfoundland and Labrador offshore area. The Project Description, submitted pursuant to the *Canadian Environmental Assessment Act*, commences the official regulatory process for obtaining the necessary approvals to permit Corridor to drill an offshore well which is expected to be drilled between mid-2012 and early 2014. Corridor is currently reviewing options available to contract a suitable offshore drilling unit, including a farm-in arrangement, in order to achieve this exploration objective in this time frame.

For additional information regarding Corridor's interest in the Gulf of St. Lawrence, see "*General Development of the Business - Recent Developments*" and "*General Development of the Business – Three Year History – Financial Year Ended December 31, 2010*".

Anticosti Island, Québec

Corridor has interests varying from 50% to 100% in 1,530,943 gross acres (891,906 net acres) in more than 30 exploration licenses covering lands across most of Anticosti Island. Petrolia Inc. acquired the remaining license percentages from Hydro-Québec in January 2008. In 2009, the Anticosti licenses were converted from exploration licenses to underground storage licenses with new 10 year terms. The underground storage licenses permit the partners to explore for oil and natural gas in a similar manner to the previous exploration licenses.

These licenses cover and offset lands where Shell and Calpine (formerly Encal) conducted 400 kilometers of modern seismic and drilled five exploration wells in 1998 and 1999 pursuant to an earlier farm-out agreement with Corridor. Corridor obtained an independent evaluation from Servipetrol indicating that the Shell/Encal/Corridor Chaloupe #1 well drilled through 44 meters of possible net oil saturated rock in the Trenton Black River formation in 1999. This potential oil zone was not recognized at the time due to the under-pressured nature of the fractured and partially dolomitized limestone reservoir. There are numerous other structures identified on seismic (large and small) with characteristics similar to the Shell/Encal/Corridor Chaloupe #1 well. This well has not been re-entered due to well issues.

Corridor, in partnership with Hydro-Québec, undertook a three-well exploration drilling program on Anticosti Island between July and early October 2005. The Corridor/Hydro-Québec MacDonald well encountered an excellent reservoir in the Trenton Black River formation which flowed large volumes of salt water on test. The well was subsequently abandoned. The Corridor/Hydro-Québec Chaloupe #1 well was a step-out from the original Shell/Encal/Corridor Chaloupe #1 well drilled in 1999, which had subsequently been evaluated to be possibly oil bearing. The Corridor/Hydro-Québec Chaloupe #1 well encountered oil shows in the Trenton Black River formation, but failed to encounter any significant permeability at that location. The Corridor/ Hydro-Québec Jupiter #1 well penetrated the large Jupiter fault zone, encountering oil shows in the Mingan and Upper Romaine formations but no significant reservoir permeability. Corridor's working interests are 75% in the Corridor/Hydro-Québec Chaloupe #1 and Corridor/Hydro-Québec Jupiter #1 wells and 50% in the Corridor/Hydro-Québec MacDonald #1 well.

Corridor, in partnership with Petrolia, undertook a three-well exploration drilling program on Anticosti Island between June and early September 2010. The Jupiter well was a re-entry of the Corridor/Hydro-Québec Jupiter #1 well and was drilled directionally in an attempt to encounter dolomitized and fractured carbonates in the Mingan and Romaine formations. The well encountered live oil shows in the Mingan Formation but no significant reservoir potential, and was subsequently abandoned. The Petrolia/Corridor Chaloupe #1 well was drilled with a sub-horizontal leg in the Black River section. The well encountered only minor dolomitized carbonates with no apparent reservoir development. Twenty-seven meters of full diameter core were cut within the Macasty organic shale as described in more detail below. The Petrolia/Corridor Saumon #1 well was also drilled with a sub-horizontal leg in the Black River section. The well encountered minor dolomitized carbonates and had very permeable reservoir development in fractured Black River carbonates. The well flowed a total of 47 cubic meters of salt water to surface, including an initial flow of 27 cubic meters (170 barrels) in the first 45 minutes. The high apparent reservoir permeability encountered, while water bearing in this well, is encouraging for future oil exploration in the area.

On February 9, 2011, Corridor announced the results of the Macasty shale core and petrophysical analyses from the Petrolia/Corridor Chaloupe #1 well on Anticosti Island (50% net working interest). Corridor and Petrolia engaged Schlumberger Canada to analyze the petrophysical logs using the results from the core analysis to calibrate the logs. Schlumberger Canada computed an average porosity and an average oil saturation for the Macasty and English Head formations in the Petrolia/Corridor Chaloupe #1 well. Schlumberger calculated high hydrocarbon saturations (80%) and porosities (6% effective) in the 40 metre thick Macasty Formation, with saturation and porosity declining in the overlying English Head Formation. These results are positive indicators for the potential of significant oil initially-in-place within the Macasty shale. Corridor and Petrolia are actively evaluating their joint venture options regarding further exploration and determination of resource potential, in order to ensure that optimal shareholder value is obtained from the ongoing programs. The Anticosti exploration program is at an early stage; further work is required to determine the potential for commercially viable resource recovery, prior to proceeding to the development phase.

On March 8, 2011, Québec's Minister of Sustainable Development, Environment and Parks, announced the release by Québec's Bureau d'audiences publiques sur l'environnement ("**BAPE**"), the environmental assessment commission, of a report prepared pursuant to the *Environment Quality Act* (Québec) on sustainable development of the shale gas industry in Québec.

The principal recommendations of the BAPE are (i) to conduct a strategic environmental assessment on shale gas in order to make an informed decision regarding the development of shale and in order to make the development of a shale-gas industry more socially acceptable, and (ii) to halt new exploratory shale drilling in Québec that involves fraccing. In response to the BAPE's report, Québec's Minister of Sustainable Development, Environment and Parks has announced that a committee of experts and representatives from government, municipalities and industry would be created to conduct a strategic environmental evaluation of shale gas. It is expected that the evaluation of the committee may take from 18-30 months. In addition, the Minister announced that Québec has placed a temporary ban on hydraulic fracturing (fraccing) such that no new drilling would be allowed for shale gas for a period of 30 months.

Subsequently, on March 16, 2011, Québec's Minister of Natural Resources and Wildlife announced that the Québec government would no longer authorize any hydraulic fracturing operations in Québec, which moratorium is effective immediately and applies to fraccing both for gas and oil, other than for scientific purposes, during the 30 month period. A panel of experts will permit limited fracturing during this period, on the condition that the fracturing activities improve knowledge about the impact of the technique used to extract natural gas from shale rock formations.

The timing and results of Québec's planned environmental assessment are not known at this time. Corridor will seek clarification on the terms and conditions required by Québec in order to continue to undertake exploration activities involving fraccing programs on Anticosti Island.

For additional information regarding Corridor's interest on Anticosti Island, see "*General Development of the Business - Recent Developments*" and "*General Development of the Business – Three Year History – Financial Year Ended December 31, 2010*".

Prince Edward Island

Corridor has a 100% working interest in two exploration licenses covering 264,129 gross acres on Prince Edward Island that were acquired in July 2004 and will expire on August 18, 2012. The licenses cover the proven gas-bearing Green Gables structure as well as a number of other natural gas prospects in Upper Carboniferous sediments in the west-central part of the Island. In September 2007, Corridor drilled the Green Gables #3 well to a total measured depth of 2545 metres. The well encountered a total of 70 metres of indicated net gas bearing sand mainly in the Bradelle Formation based on well logs and using a 6% porosity cut-off. The gas bearing sands have significant amounts of clay in the pore structure which may reduce permeability to gas flow. While fracturing the first interval in the Green Gables #3 well, in December 2007, Corridor encountered technical difficulties and the frac operations were suspended.

Pursuant to its revised agreement with PetroWorth, PetroWorth agreed to finance 100% of the costs of fracturing and testing the initial two zones in the Green Gables #3 well in early August 2008 to a maximum cost of $2 million to earn a 10% working interest in Corridor's Green Gables licence 04-03. The agreement also provides that each of Corridor and PetroWorth shall have the right to back into a 50% working interest in any licence acquired by the other party on Prince Edward Island during the next five years.

In August 2008, Corridor completed the fracturing of two intervals in the Green Gables #3 well and suspended operations there to evaluate results. PetroWorth was assigned a 10% (or 17,617 net acres) working interest in Corridor's license 04-03.

Corridor may consider propane fracturing in the Green Gables #3 well when suitable equipment is available in the region.

Natural Gas Storage Licenses

Corridor held a 100% interest in natural gas storage licenses (37,223 gross acres) located in Salt Springs in south-central New Brunswick, approximately 50 kilometres from Saint John, and had been engaged in discussions with potential partners regarding undertaking a preliminary evaluation of the potential for leaching caverns for natural gas storage and strategic oil storage in salt formations. An initial engineering study for a salt water disposal pipeline was completed, as well as an initial study determining the availability of source water to leach the storage caverns. The Salt Springs prospect also has the potential for storage of liquid petroleum products and for storing strategic reserves of oil, providing greater energy security for Atlantic Canadians.

On March 21, 2011, the Corporation was advised by New Brunswick's Department of Natural Resources that it would not renew the license and the license expired effective March 7, 2011. As a result of this decision by the New Brunswick Department of Natural Resources, the Corporation will discontinue plans to develop such natural gas storage facility.

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 March 30, 2011 and is a summary of information contained in the GLJ Reserves Report, which has an effective date of December 31, 2010 and a preparation date of March 5, 2011. 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, 2010 (Forecast Prices and Costs)

	Light and Medium Oil		Natural Gas		Natural Gas Liquids		Total Oil Equivalent Basis[1]	
Reserves Category	**Gross (mbbl)**	**Net (mbbl)**	**Gross (bscf)**	**Net (bscf)**	**Gross (mbbl)**	**Net (mbbl)**	**Gross (mboe)**	**Net (mboe)**
Proved Reserves								
Developed Producing	-	-	26.4	25.1	34	32	4,440	4,224
Developed Non Producing	-	-	-	-	-	-	-	-
Undeveloped	87	79	35.8	32.4	46	41	6,094	5,515
Total Proved Reserves	87	79	62.2	57.5	79	73	10,534	9,739
Probable Reserves	434	393	59.2	53.8	76	69	10,375	9,423
Total Proved Plus Probable Reserves	521	471	121.4	111.3	155	142	20,909	19,162
Possible Reserves [2]	173	157	118.7	107.7	151	138	20,110	18,247
Total Proved Plus Probable Plus Possible Reserves [2]	694	628	240.1	219.0	306	280	41,019	37,409

Note:

(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, 2010 Before and After Income Taxes[1] (Forecast Prices and Costs)

	Before Income Taxes[1] Discounted at (%/Year)					Unit Value Before Income Tax Discounted at 10%/Year[2]	
Reserves Category	**0% ($MM)**	**5% ($MM)**	**10% ($MM)**	**15% ($MM)**	**20% ($MM)**	**$/boe**	**$/mscf**
Proved Reserves							
Developed Producing	94.9	77.0	64.4	55.2	48.4	15.25	2.54
Developed Non Producing	0.0	0.0	0.0	0.0	0.0	0	0
Undeveloped	162.4	92.6	57.7	38.2	26.3	10.47	1.75
Total Proved Reserves	257.3	169.6	122.2	93.5	74.7	12.54	2.09
Probable Reserves	369.9	179.7	103.5	65.7	44.2	10.99	1.83
Total Proved Plus Probable Reserves	627.2	349.4	225.7	159.1	118.9	11.78	1.96
Possible Reserves [3]	820.2	365.0	204.1	129.4	88.6	11.18	1.86
Total Proved Plus Probable Plus Possible Reserves [3]	1,447.4	714.4	429.8	288.5	207.5	11.49	1.91

	After Income Taxes[1] Discounted at (%/Year)				
Reserves Category	**0% ($MM)**	**5% ($MM)**	**10% ($MM)**	**15% ($MM)**	**20% ($MM)**
Proved Reserves					
Developed Producing	94.9	77.0	64.4	55.2	48.4
Developed Non Producing	0.0	0.0	0.0	0.0	0.0
Undeveloped	143.2	84.2	53.7	36.1	25.2
Total Proved Reserves	238.1	161.2	118.1	91.4	73.6
Probable Reserves	267.9	130.6	75.7	48.4	32.8
Total Proved Plus Probable Reserves	506.0	291.8	193.8	139.8	106.4
Possible Reserves [3]	590.5	262.8	146.7	92.9	63.8
Total Proved Plus Probable Plus Possible Reserves [3]	1,096.5	554.6	340.5	232.7	170.2

Note:

(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, 2010 (Forecast Prices and Costs)								
Reserves Category	**Revenue ($MM)**	**Royalties ($MM)**	**Operating Costs ($MM)**	**Development Costs ($MM)**	**Abandonment and Reclamation Costs[3] ($MM)**	**Future Net Revenue Before Income Taxes ($MM)**	**Income Taxes ($MM)**	**Future Net Revenue After Income Taxes ($MM)**
Proved Reserves	453.3	35.0	83.6	63.9	13.4	257.3	19.1	238.1
Total Proved Plus Probable Reserves	1,012.5	86.7	145.3	132.2	21.1	627.2	121.2	506.0
Total Proved Plus Probable Plus Possible Reserves [1]	2,123.6	190.3	242.3	212.2	31.5	1,447.4	350.9	1,096.5

(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, 2010 (Forecast Prices and Costs)				
		Future Net Revenue Before Income Taxes (discounted at 10%/yr)	**Unit Value[3]**	
Reserves Category	**Production Group**	**($MM)**	**($/boe)**	**($/mscf)**
Total Proved Reserves	Light and Medium Crude Oil [1]	4.0	44.79	7.46
	Natural Gas[2]	118.2	12.25	2.04
	Total Proved Reserves	122.2	12.54	2.09
Total Proved Plus Probable Reserves	Light and Medium Crude Oil[1]	11.8	22.09	3.68
	Natural Gas[2]	213.9	11.48	1.91
	Total Proved Plus Probable Reserves	225.7	11.78	1.96
Total Proved Plus Probable Plus Possible Reserves [4]	Light and Medium Crude Oil[1]	22.7	25.55	4.26
	Natural Gas[(2]	407.0	11.15	1.86
	Total Proved Plus Probable Plus Possible Reserves	429.8	11.49	1.91

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 used by GLJ in the GLJ Reserves Report in calculating the net present value of future net revenue attributable reserves.

Year	Brent Blend Crude Oil FOB North Sea ($US/bbl)	Exchange Rate US$/Can$	Inflation rate	Henry Hub Gas Price US$/mmbtu	Nova Scotia Goldboro Can$/mmbtu
2011	88.50	0.980	0%	4.50	3.99
2012	88.25	0.980	2.0%	5.15	4.65
2013	88.50	0.980	2.0%	5.75	5.26
2014	90.50	0.980	2.0%	6.25	5.76
2015	93.67	0.980	2.0%	6.75	6.27
2016	96.05	0.980	2.0%	7.10	6.62
2017	98.76	0.980	2.0%	7.32	6.84
2018	101.24	0.980	2.0%	7.47	6.99
2019	103.95	0.980	2.0%	7.62	7.14
2020	106.06	0.980	2.0%	7.77	7.30
Thereafter	+2%/yr	0.980	2.0%	+2%/yr	+2%/yr

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, 2010, 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, 2009	87	434	521	74.3	63.3	137.6	95	81	176	12,567	11,062	23,629
Extensions and Improved Recovery	–	–	–	2.2	1.3	3.5	3	1	4	370	218	588
Technical Revisions	–	–	–	(7.2)	(5.2)	(12.4)	(9)	(7)	(16)	(1,209)	(874)	(2,083)
Discoveries	–	–	–	–	–	–	–	–	–	–	–	–
Acquisitions	–	–	–	–	–	–	–	–	–	–	–	–
Dispositions	–	–	–	–	–	–	–	–	–	–	–	–
Economic Factors	–	–	–	(2.3)	(0.2)	(2.5)	(3)	–	(3)	(383)	(33)	(416)
Production	–	–	–	(4.8)	–	(4.8)	(6)	–	(6)	(803)	–	(803)
December 31, 2010	**87**	**434**	**521**	**62.2**	**59.2**	**121.4**	**79**	**76**	**155**	**10,534**	**10,375**	**20,909**

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. 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.

Company Gross Reserves First Attributed by Year

Proved Undeveloped Reserves

	Light & Medium Oil (mbbl)	**Natural Gas (mmscf)**	**Natural Gas Liquids (mbbl)**	**Total Oil Equivalent (mboe)[1]**
Dec 31 2008	87	18,301	23	3,160
Dec 31 2009	-	7,836	10	1,316
Dec 31 2010	-	1,513	2	254
Current Total	**87**	**35,772**	**46**	**6,094**

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 (mmscf)	Natural Gas Liquids (mbbl)	Total Oil Equivalent (mboe)[(1)]
Dec 31 2008	434	32,147	41	5,833
Dec 31 2009	-	4,254	5	714
Dec 31 2010	-	1,233	2	207
Current Total	434	51,517	66	9,086

Note:

(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.

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 availability of capital to fund required infrastructure, commodity prices, production performance of re-completed wells and well re-completion success rates, the assumed effects of regulation by government agencies 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.

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	2011 ($MM)	2012 ($MM)	2013 ($MM)	2014 ($MM)	2015 ($MM)	Remainder ($MM)	Total Undiscounted ($MM)	Total Discounted at 10% ($MM)
Proved Reserves	0.2	12.9	14.6	21.1	12.1	3.1	63.9	47.6
Proved Plus Probable Reserves	0.2	18.6	37.9	30.0	42.4	3.1	132.2	97.1

At this time, Corridor's preliminary 2011 capital budget does not include any additional drilling at the McCully Field. The budget assumes that no additional funds will be utilized from other sources such as equity financings, corporate debt or asset sales. Corridor intends to finalize its 2011 capital budget after receiving Apache's proposed plans for potential further activity pursuant to the Apache Agreement. Any financing costs relating to funding the estimated future development costs would reduce future net revenue attributable to those reserves but the Corporation does not expect that such financing costs would make the development of the properties uneconomic. There can be no guarantee that funds will be available or that the board of directors of Corridor will allocate funding to develop most of the reserves in the GLJ Reserves Report. Failure to develop those reserves would have a negative impact on future net revenues.

RESOURCES INFORMATION

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.

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

Resources and contingent resources do not constitute, and should not be confused with, reserves. Reserves and resources will vary from its reserve and resource estimates, and those variations could be material.

GLJ Shale Resources Report

In May 2009, Corridor retained GLJ to estimate the quantity of shale gas resource contained within the Frederick Brook formation 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*". The GLJ Shale Resources Report was conducted in accordance with the COGE Handbook and NI 51-101 and addressed only the discovered petroleum initially-in-place, since insufficient information was available at such time to estimate the technical or economically recoverable amount of shale gas within the study area. GLJ reviewed the pertinent data collected between June 1, 2009 and December 31, 2010 in the upper part of the Frederick Brook formation, and have made no changes to the original estimates provided in the GLJ Shale Resources Report.

The GLJ Shale Resources Report, effective June 1, 2009, provided a best estimate of discovered resources and was based on all available seismic and well information within the study area provided by Corridor to GLJ. **There is no certainty that it will be commercially viable to produce any portion of these discovered resources.**

The following table sets forth the estimate of discovered resources of shale gas in the GLJ Shale Resources Report.

Best Estimate Discovered Resources(1)		
Resource	**Gross Interest**	**Working Interest(2)**
Silty/clay-rich (Upper) FB	43.2 tscf	38.2 tscf
Albitic/dolomitic (Lower) FB	24.1 tscf	20.9 tscf
Total Frederick Brook shale gas	67.3 tscf	59.1 tscf

Note:

(1) *The "best estimate" is defined as the value that best represents the expected outcome with no optimism or conservatism.*

(2) *Corridor's working interest is calculated without taking into account the 50% working interest that may be earned by Apache in approximately 116,000 acres of lands covering the Frederick's Brook shale formation pursuant to the Apache Agreement. If Apache earns such 50% working interest, Corridor estimates that the working interest in the table above will be reduced to 23.7 tscf (Silty/Clay-Rich (Upper) FB), 12.9 tscf (Albitic/Dolomitic (Upper) FB) and 36.6 tscf (Total Frederick Brook Shale). There can be no assurance that Apache will earn such 50% working interest.*

GLJ Elgin Contingent Resources Report

Corridor retained GLJ to evaluate and prepare a contingent resources report for Corridor's shale gas resources in the area surrounding the Green Road G-41 well located four kilometers north of Elgin, New Brunswick, which is only a subset of the area covered by the GLJ Shale Resources Report. See "*Description of the Properties – New Brunswick Lands - Elgin Sub-Basin*". The GLJ Elgin Contingent Resources Report is dated March 5, 2011, is effective December 31, 2010, and provides estimates of the contingent resources and net present value of such contingent resources in respect of Corridor's properties.

The GLJ Elgin Contingent Resources Report includes a "Best Estimate" which is considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability (P_{50}) that the quantities actually recovered will equal or exceed the best estimate. The gross contingent resources estimate for 2010 has been reduced from the estimate of GLJ effective December 31, 2009 to reflect the increased economic risk assigned by GLJ to the completion of shale gas wells following the initial flowback results of the Green Road B-41 well and Will DeMille G-59 well. As a result, GLJ's 2010 Low Estimate was not economic based on current forecasted natural gas prices and therefore was not provided.

	Best Estimate
Shale Gas (bscf)	
Gross Lease	396
Total Company Interest[(1)]	396
Net After Royalty[(1)]	358
Oil Equivalent (mboe)	
Gross Lease	66
Total Company Interest[(1)]	66
Net After Royalty[(1)]	60

Note:

(1) The Total Company Interest and Net After Royalty have been calculated without taking into account the 50% working interest that may be earned by Apache in approximately 116,000 acres of lands covering the Frederick Brook shale formation pursuant to the Apache Agreement. If Apache earns such 50% working interest, Corridor's "Total Company Interest" will be reduced to 198 bscf and "Net After Royalty" will be reduced to 179 bscf.

There is no certainty that it will be economically viable to produce any portion of the resources. Based on the GLJ Elgin Contingent Resources Report, Corridor's 2010 contingent natural gas resources reflect the postulated development of a first tranche of shale gas development in the vicinity of the Green Road G-41 vertical well. The report is based on Corridor's results from the G-41 well, including well logs and production test results from two fractured intervals within the Frederick Brook formation and the initial flowback results of the Green Road B-41 well and Will DeMille G-59 well. The postulated development is limited to a silty and shaly section approximately 383 meters in thickness and 14,750 acres in area, representing less than 8% of the total Frederick Brook rock volume and total shale gas potential outlined by GLJ and shown in the map included in "*Description of the Properties – New Brunswick Lands - Elgin Sub-Basin*". The postulated development is intended to indicate development potential and is not intended to predict possible Apache development plans for the area.

The primary contingencies with respect to Corridor's economic contingent resources include the uncertainty surrounding the economic viability of the related development project due to the early stage of resource evaluation. This includes the uncertainty that all internal and external approvals will be forthcoming along with documented intent to develop the resources within a reasonable time frame.

Other commercial considerations that may preclude the classification of contingent resources as reserves include factors such as legal, environmental, political and regulatory matters or a lack of markets.

The following table summarizes the net present values of future net revenue attributable to Corridor's contingent resources evaluated by GLJ in the GLJ Elgin Contingent Resources Report. The net present values are reported before income tax and have been discounted using rates of 0%, 5%, 8%, 10%, 12%, 15% and 20%. Future net revenue does not represent fair market value. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the net present value represents the fair market value of Corridor's common shares. Actual results may differ materially from the assumptions mandated by NI 51-101.

Net Present Value of Contingent Resources
as of December 31, 2010
(Forecast Prices and Costs)[(1)]

	Before Income Taxes Discounted at (%/year)						
	0% ($MM)	**5% ($MM)**	**8% ($MM)**	**10% ($MM)**	**12% ($MM)**	**15% ($MM)**	**20% ($MM)**
Best Estimate[(2)]	800.0	206.7	32.2	(43.0)	(95.8)	(146.3)	(184.3)

Note:

(1) The forecast prices used are the GLJ prices in the GLJ Reserves Report, as at January 1, 2011, and as set forth under "*Statement of Reserves and Other Oil and Gas Information – Pricing Assumptions*".

(2) The net present value has been calculated without taking into account the 50% working interest that may be earned by Apache in approximately 116,000 acres of lands covering the Frederick Brook shale formation pursuant to the Apache Agreement. If Apache earns such 50% working interest, Corridor's undiscounted net present value will be reduced to $400 million and Corridor's discounted net present value at 10% will be reduced to a negative $21.5 million.

The GLJ Elgin Contingent Resources Report is based on Corridor's resources in the Elgin Sub-Basin which is subject to the Apache Agreement. For additional information regarding development see "*General Development of the Business – General – Apache Farm-Out*" in this AIF. For information on Apache's plans see "*General Development of the Business - Recent Developments*".

Apache has until June 1, 2011 to spend a committed $25 million to undertake operations pursuant to the Apache Agreement prior to electing whether or not to spend a further $100 million to earn 50% of Corridor's interest in 116,000 acres in the Elgin/Sussex area.

OTHER OIL AND GAS INFORMATION

Oil and Gas Properties and Wells

As at December 31, 2010, Corridor had an interest in 38 gross (28 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......................	30.0	20.5	7.0	6.5
Caledonia Field....................	–	–	–	–
Subtotal...............................	30.0	20.5	7.0	6.5
Total......................................	30.0	20.5	8.0	7.5

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 wells C-75, H-28, Green Road G-41 and Mapleton N-11.

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 31, 2011 and the net area of unproven properties for which Corridor expects its right to explore, develop and exploit to expire during the next year.

Location	Gross Acres	Net Acres
McCully and Caledonia Fields, New Brunswick	77,461	59,164
Elgin Sub-Basin, New Brunswick	118,146	118,146
McCully North, New Brunswick	44,428	44,428
Havelock Area, New Brunswick	44,354	44,354
Corridor/Windsor Energy Lands, New Brunswick	106,740	53,370
Gulf of St. Lawrence, Québec (1)	123,550	123,550
Gulf of St. Lawrence, Newfoundland and Labrador	127,948	127,948
Anticosti Island, Québec	1,530,943	891,906
Prince Edward Island	264,129	264,129
TOTAL	2,437,699	1,726,995

(1) *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 licences to explore for petroleum and natural gas previously issued by the Government of Québec in the accord area.*

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 was evaluated the acres for these leases is included in unproved properties in the McCully and Caledonia Fields.

Corridor's licenses to explore the Elgin Sub-Basin (licenses 05-01 and 05-02 totaling 118,146 acres) and Havelock Area (license 05-03 in the amount of 44,354 acres) were up for renewal in 2010. Corridor has requested extensions on these licenses and is awaiting a formal response by the Province of New Brunswick.

Corridor's leases 06-01, 06-02 and 06-03 are up for renewal in 2011. No other rights of Corridor to explore, develop or exploit any of unproved properties will expire before December 31, 2011.

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 Dracut, Massachusetts less pipeline transportation costs on M&NP), 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.

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, 2010, specifically two wells drilled in Prince Edward Island, one well in the Caledonia Field, 1 well in the Elgin Sub-Basin and 28 net wells drilled in the McCully Field, is approximately $10.3 million (net present value of $2.0 million at an 8% discount). Corridor anticipates spending an estimated $0.4 million in total 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 $21.1 million ($2.1 million at a 10% discount) and $13.4 million ($2.6 million at a 10% discount) for 38.5 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 Company did not pay any income taxes in the year ended December 31, 2010. As at December 31, 2010, the Company had approximately $193.6 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.

Based on planned capital expenditure programs and current natural gas price assumptions, the Company does not expect to be cash taxable in 2011 or 2012. On a total proved reserves basis, the GLJ Reserves Report estimates that the Company will be taxable in 2021. On a proved and probable reserves basis, the GLJ Reserves Report indicates the Company will be taxable in 2017. The GLJ Reserves Report does not include capital spending on projects that have not been assigned proved and probable reserves. This additional spending could extend the Company's tax horizon.

The Company'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 Company could result in the Company paying income taxes earlier or later than expected.

Costs Incurred

The following table outlines costs incurred by Corridor during the year ended December 31, 2010 for acquisitions, dispositions and capital expenditures.

Nature of Cost	**Amount** ($M)
Acquisition Costs	
Proved	-
Unproved	-
Exploration Costs	$9,889
Development Costs	11,879
Total	**$21,768**

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the year ended December 31, 2010.

	Development		**Exploration**		**Total**	
Wells	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Gas	1.0	1.0	3.0	2.0	4.0	3.0
Oil	-	-	-	-	-	-
Service	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	1.0	1.0	3.0	2.0	4.0	3.0

Corridor's exploration and development activities in the near term will be focused on the Properties discussed under the heading "*Description of the Properties*".

Production Estimates

The following table summarizes the volume of total proved gross working interest production estimated for the financial year ended December 31, 2011 using forecast prices and costs. The McCully Field accounts for all of this production.

	2011 Estimated Production Forecast Prices and Costs	
	Total Proved	**Total Proved Plus Probable**
Light and Medium Oil (bblpd)	33	50
Natural Gas (mmscfpd)	12.6	13.0
Natural Gas Liquids (bblpd)	16	17
Total (boepd)	2,147	2,225

Production History and Netbacks

The average daily production volumes, prices, royalties, production costs and netbacks for Corridor's natural gas for each quarter in 2010 and the financial year ended December 31, 2010 are set out below. Corridor did not produce any crude oil and had only nominal sales of natural gas liquids in 2010. The McCully Field accounted for all of this production.

	Three months ended				Year Ended
	March 31, 2010	**June 30, 2010**	**September 30, 2010**	**December 31, 2010**	**December 31, 2010**
Natural Gas					
Average Daily Gas Production (mmscfpd)	14.9	13.6	11.0	13.3	13.2
Price ($/mscf)	$6.77	$4.95	$4.96	$5.74	$5.66
Royalties ($/mscf)	(0.22)	(0.02)	(0.03)	(0.21)	(0.13)
Production & Transportation Costs ($/mscf)	(2.05)	(2.04)	(2.30)	(2.33)	(2.17)
Netback ($/mscf)	**$4.50**	**$2.89**	**$2.63**	**$3.20**	**$3.36**

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 our 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 our 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 our operations. The Corporation cannot predict the ultimate cost of compliance with these requirements or their effect on our 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 our facilities could have a material adverse effect on our results of operations, competitive position, or financial condition.

Although Corridor does not expect that these controls and regulations will affect the operations of Corridor 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.

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 National Energy Board (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 intraprovincial, 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 Governor in Council.

Natural Gas Liquids

The price of 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: (1) 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); (2) impose a higher export price than domestic price (subject to an exception relating to certain voluntary measures that restrict the volume of exports); and (3) 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 from two to five years. Other terms and conditions to maintain a mineral lease are set forth in the relevant legislation or are negotiated.

Pipeline Capacity

Corridor projects an excess of available 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 US 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 our production. Crown royalties 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

In New Brunswick, the Crown royalty rate is based on monthly production. For natural gas, the royalty rate is set at 10% of the actual selling price or fair market value at the time and place of production, whichever is greater, free of any deductions. The royalty payable on oil is based on monthly production from each well and ranges from 5 to 12%, calculated on the actual selling price or fair market value at the time and place of production, whichever is greater, free of any deductions.

Prince Edward Island

The royalty rate for natural gas in Prince Edward Island is set at 10% of the selling price or fair market value for natural gas in the Province. The royalty payable on oil is based on monthly production from each well and ranges from 5 to 12% of the actual oil produced.

Québec

As 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% for crude oil and 10 - 12.5% for natural gas apply, depending on the quantity produced. On March 17, 2011, the Québec Minister of Finance tabled the 2011-2012 Budget, which states that "In pursuing the objective of developing Québec's oil and gas resources, the government will ensure that natural gas production is economically profitable, environment-friendly and safe for the public". As part of the budget, the Québec government announced the adoption of a new royalty regime whereby the royalty rate for natural gas will vary from 5 to 35% of net revenue depending on both price and production, and that it will update the laws and regulations on oil and gas in Québec. The date that the new royalty regime will come into effect is uncertain as it is to follow a strategic environmental assessment and establishment of a corresponding legal and regulatory framework. The announcement did state, however, that wells completed prior to the introduction of the new royalty regime will be able to operate under the current royalty system, even after the new regime takes effect.

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 closure 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 has utilized operating and disposal practices that were standard in the industry at the time, 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 our control. These properties and the wastes disposed thereon may be subject to laws and regulations imposing joint and several, strict liability without regard to fault or the legality of the original conduct that could require us to remove previously disposed wastes or remediate property contamination, or to perform well plugging or pit closure or other actions of a remedial nature to prevent future contamination.

The recent shale gas development in North America has raised environmental concerns, particularly in relation to water. Hydraulic fracturing is currently used to extract shale gas in British Columbia, Alberta, Saskatchewan and in certain states in the U.S. The U.S. has had more experience with fraccing and regulatory approach by the states to shale gas development has not been consistent. Apache has conducted hydraulic fracturing in respect of two horizontal shale gas wells drilled in Elgin, New Brunswick in accordance with the Apache Agreement. In addition, Corridor engages third parties to conduct fracturing and other well stimulation services in respect of its operations in New Brunswick. In Alberta and British Columbia, where the Canadian shale gas industry and the associated regulatory regime are more advanced, there is no suggestion that there will be any impediment on hydraulic fracturing in respect of shale gas. In New Brunswick, the Minister of Natural Resources announced there would be no moratorium put in place on shale gas development.

The Corporation believes that it is reasonably likely that the trend in environmental legislation and regulation will continue toward stricter standards. While Corridor believes that it is in substantial compliance with applicable environmental laws and regulations in effect at the present time and that continued compliance with existing requirements will not have a material adverse impact on Corridor, Corridor cannot give any assurance that it will not be adversely affected in the future. Corridor has established internal guidelines to be followed in order to comply with environmental laws and regulations in the jurisdictions in which it operates. Corridor employs an environmental, health, and safety department whose responsibilities include providing assurance that our operations are carried out in accordance with applicable environmental guidelines and safety precautions. Although Corridor maintains pollution insurance against the costs of cleanup operations, public liability, and physical damage, there is no assurance that such insurance will be adequate to cover all such costs or that such insurance will continue to be available in the future.

Greenhouse Gases and Industries Air Pollutants

Kyoto Protocol, Copenhagen Accord and Cancun Agreement

Canada is a signatory to the United Nations Framework Convention on Climate Change (the "**Convention**") and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nation-wide emissions of carbon dioxide, methane, nitrous oxide and other greenhouse gases ("**GHG**"). However, the Government of Canada has concluded that Canada will not meet its commitment to the Kyoto Protocol and has been developing an alternative strategy for reducing Canada's GHG emissions. From December 6 to 18, 2009, government leaders and representatives from approximately 170 countries met in Copenhagen, Denmark (the "**Copenhagen Conference**") to attempt to negotiate a successor to the Kyoto Protocol, which expires in 2012. The primary result of the Copenhagen Conference was the Copenhagen Accord, which represents a broad political consensus rather than a binding international treaty like the Kyoto Protocol and has not been endorsed by all participating countries. The Copenhagen Accord reinforces the commitment to reducing GHG emissions contained in the Kyoto Protocol and promises funding to help developing countries mitigate and adapt to climate change. Although Canada has committed under the Copenhagen Accord to reducing its GHG emissions by 17% from 2005 levels by 2020, the Copenhagen Accord does not establish binding GHG emissions reduction targets. The Copenhagen Accord calls for a review of implementation of its stated goals before 2016. In late 2010, another climate change conference was held in Cancun, Mexico but, like the Copenhagen Accord, it did not result in a binding treaty. The Cancun Agreement does recognize that global reductions in GHG emissions are required to limit global temperature increases to less than 2°C and that the parties should consider limiting any increase to less than 1.5°C.

Federal

The Government of Canada previously released the *Regulatory Framework for Air Emissions*, updated March 10, 2008 by *Turning the Corner: Regulatory Framework for Industrial Greenhouse Gas Emissions* (collectively, the "**Regulatory Framework**"), for regulating GHG emissions by proposing mandatory emissions intensity reduction obligations on a sector by sector basis. Legislation to implement the Regulatory Framework had been expected to be put in place, but the federal government has delayed the release of any such legislation and potential federal requirements in respect of GHG emissions are unclear. In 2009, the Government of Canada announced its commitment to work with the provincial governments to implement a North American-wide 'cap and trade' system for GHG emissions, in cooperation with the United States. On January 30, 2010, the Government of Canada announced its new target to reduce overall Canadian GHG emissions by 17% below 2005 levels by 2020, from the previous target of 20% from 2006 levels by 2020, to align itself with the GHG emission reduction goals of the United States.

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 either federal GHG regulations or an integrated North American 'cap and trade' system will or will not be implemented, or what obligations might be imposed under any such system. As the details of the implementation of any federal legislation for GHGs have not been announced, the effect on Corridor's operations cannot be **determined at this time.**

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.

Prince Edward Island

The Province of Prince Edward Island released A Strategy for Reducing the Impacts of Global Warming in 2008 which reiterated its commitment of reducing its GHG emissions to 10% below 1990 levels by 2020. However, the Province has not implemented GHG emission reduction legislation at this time.

Québec

The Province of Québec has adopted the 2006 – 2012 Climate Change Action Plan ("**Plan**"), which calls for governmental actions that now target a 20% reduction in GHG emissions below 1990 levels by 2020. The Plan includes fuel oil energy efficiency measures, measures to encourage cleaner energy alternatives and tightened fuel oil sulphur level standards. While the Plan itself does not contain mandatory and enforceable GHG emission reduction targets, policies that may result from negotiations under it may have operational or financial adverse consequences for our business. Québec has also enacted a carbon tax to be levied against energy producers and distributors in the Province.

Québec is a partner in the Western Climate Initiative ("**WCI**") which is an organization made up of four Canadian provinces (B.C., Manitoba, Ontario, and Québec) and seven states (Arizona, California, Montana, New Mexico, Oregon, Utah and Washington). The WCI is working towards implementing a regional cap-and-trade program that is expected to come into effect by 2012. As part of the overall climate change action plan, the Province has passed the Environmental Quality Act that empowers the government to set emission limits, establish reporting requirements for GHG emitters and also enables it to take part in the implementation of the WCI cap-and-trade system. It should be noted that the provisions relating to emission limits and the cap-and-trade system in the Environmental Quality Act have not yet been proclaimed into force.

RISK FACTORS

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

The Corporation anticipates making substantial capital expenditures for the exploration, development and production of oil and natural gas reserves in the future. 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 financial condition, results of operations or prospects.

The Corporation does not presently have sufficient financial resources to undertake by itself all of its planned exploration and development programs beyond 2011. 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 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 will be successful, or achieved on terms favourable to the Corporation or its existing shareholders. The failure of Corridor to obtain additional financing 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. In addition, the failure of any joint venture partner to obtain any required financing could adversely affect the Corporation's ability to complete the exploration or development of any such joint venture project on a timely basis.

Corridor currently has a $20 million revolving short term loan with a Canadian chartered bank that matures, subject to mutual agreement to extend, on July 30, 2011. As at the date hereof, there is no amount drawn down on this facility. This credit facility can be increased at any time up to the current approved borrowing base of $26 million, subject to the bank reconfirming this borrowing base. 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.

Corridor anticipates that it has sufficient financial resources (working capital and anticipated cash from McCully production) to undertake all of its planned exploration and development program for the 2011 year, as set forth in its preliminary 2011 capital budget, without accessing its 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 dependant 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.

Third Party Risk

In the normal course of our 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 one large credit-worthy purchaser under normal industry payment terms. Corridor's receivables from joint venture partners are also subject to normal credit risks in the natural gas industry. Management believes credit risk on these amounts is low and has not made any provision for an allowance for bad debts.

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*" in the AIF. 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.

Environmental

The direct and indirect costs of the various GHG regulations, existing and proposed, may adversely affect our 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 our emissions or emissions intensity to future required levels may significantly increase operating costs or reduce the output of the projects. 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 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 Corridor'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 the Company 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 are committed to continued compliance. Corridor believes that it is reasonably likely that a trend towards stricter standards in environmental legislation will continue and Corridor anticipates making increased expenditures of both a capital and an expense nature as a result of increasingly stringent environmental laws.

Prices, Markets and Marketing

The marketability and price of oil and natural gas will be affected by numerous factors beyond the Corporation's control. New technologies and drilling techniques are allowing recovery of gas and oil trapped in shale. If such resources are developed, it may have a substantial impact on the price of gas and oil and on the energy market generally. The ability to market natural gas may depend upon the Corporation's ability to acquire space on pipelines that deliver natural gas to commercial markets. The Corporation may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing facilities, and related to operational problems with such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The Corporation's revenues, profitability and future growth and the carrying value of its properties are substantially dependent on prevailing prices of gas and oil. The Corporation's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, 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, the actions of the Organization of Petroleum Exporting Countries, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Corporation's carrying value of its proved reserves, borrowing capacity, revenues, profitability and cash flows from operations. No assurance can be given that prices for oil or natural gas will be sustained at levels that will enable the Corporation to operate profitably.

Volatile oil and gas 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.

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. 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*" in the AIF, 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 is exposed to foreign exchange rate changes, as sales of natural gas from the McCully Field are quoted in United States dollars. In addition, a significant amount of the Corporation's costs are denominated in Canadian dollars with the exception of transportation costs. In recent years, the Canadian dollar has increased materially in value against the United States dollar. Such material increases in the value of the Canadian dollar have negatively impacted the Corporation's natural gas revenues. Further material increases in the value of the Canadian dollar would exacerbate this negative impact. 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.

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.

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 oil and gas, royalty rates, the assumed effects of regulation by governmental agencies 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 and resources quantities included in the "Statement of Reserves and Other Oil and Gas Information" and "Resource Information" set forth in the AIF. 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, 2010 setting forth certain information relating to certain natural gas reserves of Corridor's properties, specifically the McCully Field, 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 in the GLJ Shale Resources Report and the GLJ Elgin Contingent Resources Report will be reduced to the extent that such activities do not achieve the level of success assumed in such reports.

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.

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

It is the practice of Corridor in acquiring oil and gas leases or interests in oil and gas leases not to undergo the expense of retaining lawyers to fully examine the title to the interest to be placed under lease or already placed under the lease. Rather, Corridor relies upon the judgment of oil and gas lease brokers or landmen who actually do the field work in examining records in the appropriate governmental office before attempting to place under lease a specific interest. The Corporation believes that this practice is widely followed in the oil and gas industry.

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.

Implementation of IFRS

On January 1, 2011, IFRS became the generally accepted accounting principles in Canada for publicly accountable enterprises, including Corridor. The adoption date of January 1, 2011 requires the restatement, for comparative purposes, of amounts reported by Corridor for the year ended December 31, 2010, including the opening balance sheet as at January 1, 2010. While IFRS uses a conceptual framework similar to Canadian GAAP, there are significant differences that must be evaluated. The implementation of IFRS may result in significant adjustments to Corridor’s financial results, which could negatively impact our business. At this time, Corridor cannot definitively quantify the full impact that adopting IFRS will have on its future financial position and future results. For more information, and Corridor’s estimate of the impact on the Corporation’s January 1, 2010 opening balance sheet, please refer to the Corporation’s Management, Discussion and Analysis for the year ended December 31, 2010.

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 of Corridor 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, 2011, there were 88,447,466 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 Toronto Stock Exchange 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, 2010:

Period	High ($)	Low ($)	Volume (Common Shares)
2010			
January	5.990	4.350	2,678,365
February	4.870	3.910	2,703,661
March	4.690	3.910	3,416,598
April	6.280	4.410	9,316,132
May	6.080	4.310	3,433,667
June	5.680	4.880	3,677,767
July	5.980	4.780	2,803,609
August	6.250	4.790	2,803,609
September	5.450	4.590	4,894,508
October	6.990	5.170	4,848,613
November	7.380	6.470	6,819,154
December	7.780	3.940	14,318,514

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
Phillip R. Knoll Halifax, Nova Scotia	September 21, 2011	Director, President and Chief Executive Officer	President and Chief Executive Officer of Corridor since October 18, 2011. Prior thereto, Mr. Knoll was President of Knoll Energy Inc. (a private energy consulting company) since 2005.
Norman W. Miller(3) Halifax, Nova Scotia	March 1995	Director	Past President and Chief Executive Officer of Corridor
J. Douglas Foster(2) Calgary, Alberta	May 1998	Director and Chairman	Partner, Bennett Jones LLP (law firm)
John H. Bray(1)(2) Tampa, Florida	February 1999	Director	President of Richland Properties Inc. (a private property development company)
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

Name and Municipality of Residence	Director Since	Office or Position with Corridor	Present Occupation and Positions Held During the Last Five Years
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(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.
Larry Huskins Halifax, Nova Scotia	-	Senior Drilling and Completions Engineer	Senior Drilling and Completions Engineer since June 2006.
Douglas Bailey Rothesay, New Brunswick	-	Production Operations Manager	Production Operations Manager since October 2006.
Dr. Tom Martel Halifax, Nova Scotia	-	Chief Geologist	Chief Geologist since April 1998.

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, 2011, the directors and executive officers of Corridor, as a group, beneficially owned or controlled or directed, directly or indirectly, 6,423,971 Common Shares, representing approximately 7.3% of the issued and outstanding Common Shares. In addition, directors and executive officers held options to purchase an additional 3,495,333 Common Shares, resulting in directors and executive officers holding 10.7% 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, no director or executive officer of Corridor (a) 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) 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) 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 has 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.

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, (i) 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 (ii) 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.

To the knowledge of Corridor, in the last ten years, 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, has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, has become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold his or her assets or the assets of his or her holding company.

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

The only material contract entered into by Corridor within the most recently completed financial year or before the most recently completed financial year but still in effect, other than during the ordinary course of business is the Apache Agreement, a copy of which is available on SEDAR at www.sedar.com.

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, 2010. 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 was evaluated by GLJ, as independent qualified reserves evaluators. As at the date hereof, the principals of GLJ, 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 John Bray. Each of Mr. Penner, Mr. Bray and Mr. Desmarais 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 Accountant and 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.
John Bray	Mr. Bray is the President of Richland Properties Inc., a position he has held since 1979. Richland Properties Inc. is a property development company with operations in the United States. Mr. Bray obtained a Bachelor of Science in Geological Engineering and an MBA from the University of Manitoba. Mr. Bray is financially literate by virtue of over 30 years of entrepreneurial business experience.

External Auditor Service Fees

PricewaterhouseCoopers LLP are Corridor's auditors for the year ended December 31, 2010, previously Grant Thornton, LLP, Chartered Accountants had served as Corridor's auditors since 1996. The following table sets forth the Audit Fees, Audited – Related Fees, Tax Fees and All Other Fees billed by PricewaterhouseCoopers LLP and Grant Thornton LLP in the financial years ended December 31, 2010 and December 31, 2009.

	2010	**2009**
Audit Fees[(1)]	$136,763	$138,920
Audit-Related Fees[(2)]	–	–
Tax Fees[(3)]	39,000	–
All Other Fees[(4)]	–	–
Total	$175,763	$138,920

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.

(2) "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.

(3) "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.

(4) "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 Commons 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, 2010.

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.

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, 2010. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2010, 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, 2010, 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	March 5, 2011	Canada	-	225,675	-	**225,675**

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.

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, March 24, 2011

ORIGINALLY SIGNED BY

Jodi L. Anhorn, M. Sc., P. Eng.
Vice-President

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, 2010, 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, on the recommendation of the Reserves Committee, has 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.

"*Phillip R. Knoll*"
Phillip R. Knoll
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, 2011

APPENDIX "C"

CORRIDOR RESOURCES INC.

TERMS OF REFERENCE OF THE AUDIT COMMITTEE

Policy Statement

It is the policy of Corridor Resources Inc. (the "**Corporatio**n") 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 4 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.