Connacher

OIL AND GAS LIMITED

ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2009

March 19, 2010

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FORWARD LOOKING INFORMATION

Certain statements in this Annual Information Form are "forward looking information" within the meaning of applicable securities laws. Forward looking information is frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", "scheduled", "potential", or other similar words, or statements that certain events or conditions "may", "should" or "could" occur. Forward looking information is based on the Corporation's expectations regarding its future growth, results of operations, production, future capital and other expenditures (including the amount, nature and sources of funding thereof), competitive advantages, plans for and results of drilling activity, environmental matters, business prospects and opportunities. Such forward looking information reflects the Corporation's current beliefs and assumptions and is based on information currently available to it. Forward looking information involves significant known and unknown risks and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward looking information including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve and resource estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the Corporation's ability to access sufficient capital from internal and external sources, the risks discussed under "Risk Factors" and elsewhere in this Annual Information Form and in the Corporation's public disclosure documents, and other factors, many of which are beyond the Corporation's control. Although the forward looking information contained in this Annual Information Form is based upon assumptions which the Corporation believes to be reasonable, the Corporation cannot make assurances that actual results will be consistent with such forward looking information. Such forward looking information is made as of the date of this Annual Information Form, and the Corporation assumes no obligation to update or revise them to reflect new events or circumstances, except as required by law. Due to the risks, uncertainties and assumptions inherent in forward looking information, prospective investors in the Corporation's securities should not place undue reliance on this forward looking information.

Specific forward looking information contained in this Annual Information Form includes, among others, statements regarding:

- the operation of the Corporation's facilities, including Pod One, Algar, the Refinery, and its conventional oil and gas properties;
- the scope, scale and costs of the Algar Project and the timeline for completing plant construction, commissioning of the plant and steaming of the wells prior to start up of bitumen production;
- the Corporation's estimated future bitumen production and the timing associated therewith;
- estimates of the Corporation's reserves and resources and estimates of the present value of the future net revenue as evaluated by GLJ;
- the scope of the Corporation's 2010 winter core hole and conventional drilling program;
- estimates relating to the Corporation's 2010 capital expenditure budget;
- the anticipated use of the Revolving Credit Facility;
- the Corporation's expansion plans for its properties, including the timing thereof and the expected increases in production and revenues attributable to such expansion plans;
- the Corporation's planned construction of a cogeneration facility at the Algar Project;
- the Corporation's planned installation of electric submersible pumps ("**ESPs**");
- the Corporation's anticipated future maintenance and sustaining capital costs;
- the Corporation's anticipated Refinery throughput and performance of the Refinery;
- the Corporation's ability to market products successfully to its current and anticipated customers;

- the Corporation's expectations regarding future activity levels in the Canadian oil sands and the possible impact thereof on the price of steel and services and the availability of labour;
- the Corporation's expectations with respect to trends to emerge in the Canadian oil and gas sector including consolidation activity, acquisition opportunities and asset rationalization;
- the Corporation's expectations regarding the future price discount of heavy crude oil compared to light crude oil and the price of natural gas and the anticipated impact thereof on the Canadian oil and gas industry;
- future regulations which may come into effect and the impact of such regulations, governmental controls and applicable royalty rates on the Corporation's operations;
- the Corporation's plans for the transportation of the bitumen it produces and availability of a pipeline to transport dilbit;
- the Corporation's intention to maintain financial flexibility;
- the discussions regarding possible joint venture arrangements to accelerate the development of the Corporation's oil sands resources;
- the Corporation's competitive advantages and ability to compete successfully; and
- the Corporation's expectations regarding the development and production potential of its properties.

With respect to forward looking information contained in this Annual Information Form, the Corporation has made assumptions regarding, among other things:

- production rates and production decline rates;
- the Corporation's ability to recover reserves;
- the Corporation's ability to optimize operating costs;
- future bitumen, natural gas and crude oil prices, heavy oil differentials, refining spreads, interest rates and foreign exchange rates;
- future royalty and taxation rates;
- the cost of expanding and maintaining the Corporation's property holdings;
- well abandonment costs and salvage values;
- the Corporation's ability to obtain qualified staffing and equipment in a timely and cost-efficient manner to meet its demand;
- the timing for receipt of required regulatory approvals to proceed with future projects;
- the timing of completion of construction, plant commissioning, commencing steaming and production from the Algar Project;
- the ability to produce refined products that meet customer specifications;
- the impact of increasing competition; and
- the Corporation's ability to obtain financing on acceptable terms.

Many of the foregoing assumptions are subject to change and are beyond the Corporation's control.

Some of the risks that could affect the Corporation's future results and could cause results to differ materially from those expressed in the forward looking information include:

- the decline of crude oil and natural gas prices;
- changes in refining spreads to WTI and changes in the differential pricing between heavy and light crude oil prices;
- volatility of refining gross margins, including the price of feedstocks and the prices for refined products;
- inefficiencies, curtailments or shutdowns in the Refinery's operations or in pipelines used to transport crude oil to the Refinery and instability of the Refinery's throughput performance;
- general economic conditions;
- currency fluctuations;
- difficulties encountered in delivering diluent to the Corporation's oil sands project at Great Divide and dilbit to commercial markets;
- changes in, or the introduction of new, government regulations relating to the business of the Corporation;
- difficulties or interruptions encountered and additional costs incurred during the production of bitumen, crude oil and natural gas;
- performance and availability of facilities owned by third parties;
- costs associated with producing bitumen;
- timing, difficulties or delays encountered and additional costs relating to the construction of the Algar Project and the construction of future expansions;
- the impact of competition;
- the need to obtain required approvals and permits from regulatory authorities;
- liabilities stemming from damage to the environment, accidental or otherwise;
- compliance with and liabilities under environmental laws and regulations;
- the uncertainty of estimates by GLJ with respect to the Corporation's reserves and resources;
- changes in customer demand;
- impacts of fossil fuel combustion on climate change, including potential impact on demand for the Corporation's products;
- failure to obtain third party consents and approvals, when required;
- changes to the royalty regime in respect of the Corporation's bitumen, crude oil and natural gas production;
- the impact of amendments to the income tax laws or government incentive programs on the Corporation;
- the uncertainty of the Corporation's ability to attract capital and the adequacy of the Corporation's liquidity;

- foreign, political, economic and other uncertainties that impact the price of Petrolifera shares; and
- stock market volatility and the basis of market valuations.

In addition, design capacity is not necessarily indicative of the stabilized production levels that may be achieved at the Corporation's SAGD facilities. Moreover, reported average or instantaneous production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this Annual Information Form due to, among other factors, difficulties or interruptions encountered during the production of bitumen. Actual capital costs may differ from estimates of capital costs prepared by Management in connection with construction at Algar and such differences may be material. Estimated capital costs are based on historical experience in constructing Connacher's first SAGD project at Great Divide and have been adjusted for inflation, actual expenditures incurred to date and existing contractual commitments. However, costs for and access to required labour, services and equipment, operational efficiencies or difficulties in construction and drilling, changes in scope of design and weather conditions may individually or collectively materially impact on the actual capital costs incurred in the construction of Algar.

The information contained in this Annual Information Form, including the information provided under the heading "Risk Factors", identifies additional factors that could affect the Corporation's operating results and performance. Statements relating to "reserves" and "resources" are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and can be profitably produced in the future. The assumptions relating to the reserves and resources of the Corporation are discussed under "Oil, Natural Gas and Bitumen Reserves and Resources - Oil, Natural Gas and Bitumen Reserves" and "Oil, Natural Gas and Bitumen Reserves and Resources - Bitumen Resources", respectively.

Information contained in this Annual Information Form relating to Petrolifera, including information relating to Petrolifera's future exploration and development plans, capital expenditures and reserves and future net revenue associated therewith constitute forward looking information that has been publicly released by Petrolifera. This information is subject to change at the discretion of the Board of Directors of Petrolifera. The Corporation does not control the decisions of the Board of Directors of Petrolifera.

Forward looking information is expressly qualified in its entirety by this cautionary statement. The forward looking information is only made as of the date of this Annual Information Form.

ABBREVIATIONS AND DEFINITIONS

In this Annual Information Form, the terms and abbreviations set forth below have the following meanings:

"bbl"	Barrel	**"Mboe"**	One thousand barrels of oil equivalent
"bbl/d"	Barrels per day	**"Mcf"**	One thousand cubic feet
"boe"	Barrels of oil equivalent	**"Mcfpd"**	One thousand cubic feet per day
"boepd"	Barrels of oil equivalent per day	**"Mcfe"**	One thousand cubic feet of natural gas equivalent
"m"	metre	**"MMcf"**	One million cubic feet
"km"	kilometre	**"MMcfpd"**	One million cubic feet per day
"M$"	thousands of Canadian dollars	**"MMBtu"**	One million British thermal units
"MM$"	millions of Canadian dollars	**"NGL"**	Natural gas liquids
"Mbbl"	One thousand barrels	**"WTI"**	West Texas Intermediate

Note: For the purposes of this document, 6 Mcf of natural gas and 1 bbl of NGL each equal 1 bbl of oil. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

"**1P**" means the proved reserve category, as defined in the COGE Handbook;

"**2P**" means the proved and probable reserve categories, as defined in the COGE Handbook;

"**3P**" means the proved, probable and possible reserve categories, as defined in the COGE Handbook;

"**ABCA**" means the *Business Corporations Act* (Alberta), S.A. 2000, c. B-9, together with any amendments thereto and all regulations promulgated thereunder;

"**Algar**" or "**Algar Project**" means the Algar project, the Corporation's second 10,000 bbl/d SAGD bitumen facility and wells located at Great Divide;

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

"**Common Shares**" or "**Connacher Shares**" means the common shares in the share capital of the Corporation;

"**Connacher**" or the "**Corporation**" means Connacher Oil and Gas Limited and its subsidiaries, unless the context otherwise requires;

"**Connacher GLJ Report**" means the independent engineering evaluation of the crude oil, bitumen, natural gas liquids and natural gas interests of the Corporation prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineering consultants of Calgary, Alberta, dated February 12, 2010 and effective December 31, 2009;

"**Contingent Resources**" means those quantities of petroleum estimated, as of 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;

"**dilbit**" means diluted bitumen;

"**EIA**" means Environmental Impact Assessment;

"**ERCB**" means Energy Resources Conservation Board;

"**Great Divide**" means the Divide area located in northeastern Alberta where the Corporation's Pod One and Algar projects are located;

"**Management**" means management of the Corporation;

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

"Notes" means collectively the First Lien Notes and the Second Lien Notes;

"**Petrolifera**" means Petrolifera Petroleum Limited;

"**Petrolifera AIF**" means the annual information form of Petrolifera for the year ended December 31, 2009 dated March 17, 2010;

"**Petrolifera GLJ Report**" means the independent engineering evaluation of the crude oil, natural gas liquids and natural gas interests of Petrolifera prepared by GLJ, independent petroleum engineering consultants of Calgary, Alberta, dated March 5, 2010 and effective December 31, 2009;

"**Prospective Resources**" means those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects;

"**Pod One**" means the Corporation's first 10,000 bbl/d SAGD bitumen facility and wells located at Great Divide;

"**Refinery**" means the Corporation's 9,500 bbl/d heavy crude oil refinery located in Great Falls, Montana;

"**SAGD**" means steam-assisted gravity drainage;

"**SOR**" means steam-oil ratio;

"**Sayer Energy Advisors Report**" means the independent evaluation of the undeveloped land acreage of the Corporation prepared by Sayer Energy Advisors ("**Sayer**"), independent oil and gas advisory firm of Calgary, Alberta, dated January 22, 2010 and effective December 31, 2009; and

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

In this Annual Information Form, references to "dollars" and "$" are to the currency of Canada, unless otherwise indicated.

THE CORPORATION

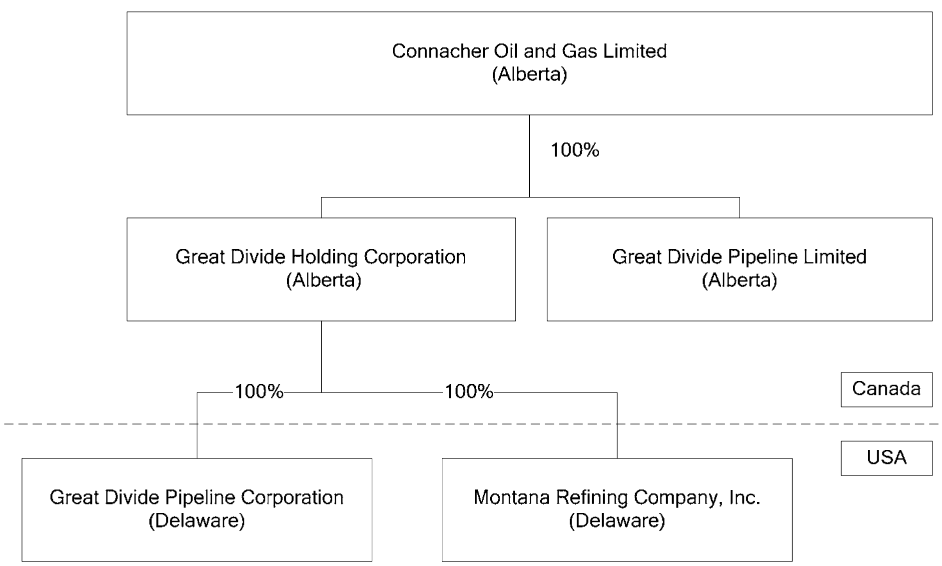
Incorporation and Organization

The Corporation was formed on July 3, 1997 through the amalgamation pursuant to the ABCA of Petro Power Energy Inc. and Justinian Explorations Ltd. and continued as Justinian Explorations Ltd., a public corporation listed on the TSX Venture Exchange. On January 23, 2001 the outstanding Connacher Shares were consolidated on a ten-for-one basis and the name of the Corporation was changed to Connacher Oil and Gas Limited. Trading in the Connacher Shares under the symbol "CLL" commenced on the TSX Venture Exchange on March 23, 2001. This listing was surrendered on August 1, 2003 when the Corporation graduated to and commenced trading on the TSX.

As of December 31, 2009, the Corporation had four wholly-owned subsidiaries, Great Divide Pipeline Limited and Great Divide Holding Corporation, both of which are corporations incorporated under the ABCA and Great Divide Pipeline Corporation and Montana Refining Company, Inc. both of which are organized pursuant to the laws of the State of Delaware. The Corporation also has a significant equity interest in Petrolifera. See "Business of the Corporation - Ownership of Petrolifera".

The Corporation has its head and principal office at Suite 900, 332 – 6th Avenue S.W., Calgary, Alberta, T2P 0B2 and its registered office at 3700, 400 Third Avenue S.W., Calgary, Alberta, T2P 4H2.

The following chart illustrates the Corporation's organizational structure as of December 31, 2009 and the date of this Annual Information Form:



General Development of the Corporation

Connacher is an integrated oil company, primarily engaged in the exploration for, and the development, production and marketing of bitumen, dilbit, crude oil and natural gas, the operation of a heavy oil refinery located in Great Falls, Montana and the marketing of associated refined products. The Corporation's principal asset is its 100 percent working interest in approximately 98,000 net acres of oil sands leases. These are primarily situated in the Divide, Thornbury and Quigley regions and include a 50 percent working interest in the Halfway Creek region, all southwest of Fort McMurray, Alberta. The Corporation's first 10,000 bbl/d SAGD project at Great Divide, referred to herein as Pod One, is currently producing and the Corporation's second 10,000 bbl/d oil sands project at Great Divide, referred to as Algar or the Algar Project, is currently under construction and anticipated to be completed in mid-April 2010. During the past three years, the primary focus of the Corporation has been the completion of construction, commissioning, start-up and production ramp-up of Pod One, the delineation of additional resources to support an application to construct the Algar Project, the receipt of regulatory approvals for the Algar Project, commencement of construction of Algar and financing activities to support the Corporation's capital intensive oil sands activities. In addition, exploration and delineation core hole drilling and three-dimensional ("**3D**") seismic programs have been conducted in support of plans to file an application to further expand plant capacity at Great Divide, initially to 44,000 bbl/d. The Corporation also owns conventional producing crude oil and natural gas properties at Battrum, Saskatchewan and at Marten Creek, Gilby/Three Hills and Latornell, Alberta and an approximate 22 percent equity interest in Petrolifera, a public Canadian crude oil and natural gas production, exploration and development company active in Argentina, Peru and Colombia. The following is a general description of the development of the Corporation over the past three years.

In the winter of 2007, Connacher completed an extensive and successful 81 core hole drilling and 3D seismic program on its main lease block at Great Divide, resulting in a marked expansion of its reserve and resource base and supporting Management's decision to proceed with an application for a second oil sands plant at Algar also with a design capacity of 10,000 bbl/d of bitumen. The proposed plant site is approximately eight km east of the Pod One plant. This application was submitted to regulatory authorities in June 2007.

In May 2007, Connacher completed a "bought-deal" financing for $100,050,000 aggregate principal amount of convertible senior unsecured debentures due June 30, 2012. Proceeds of the offering were used by the Corporation to repay short term borrowings and to fund capital expenditure programs in respect of the development of its oil sands projects and conventional projects and the remainder was used for operating expenses.

Construction at Pod One, including the drilling of 15 SAGD well pairs, was completed in August 2007, within the 300 day construction schedule and at a total capital cost of approximately $272 million, excluding approximately $25 million of sunk costs, capitalized interest and capitalized general and administrative expenses. Following plant commissioning in September 2007, Connacher commenced steam injection into the SAGD well pairs. In October 2007, Connacher delivered and sold to market its first truckload of dilbit from Pod One.

In November 2007, Connacher completed a "bought-deal" financing of 10,350,000 flow-through common shares at a price of $5.00 per flow-through share. Connacher also issued an aggregate of 100,000 flow-through shares at a price of $5.00 per flow-through share pursuant to a private placement. The total gross proceeds of $52,250,000 from the financings were used to drill exploratory core holes and conduct 3D seismic to assist in the delineation of additional oil sands reserves and resources at Great Divide and Halfway Creek.

In December 2007, Connacher completed the sale of US$600 million aggregate principal amount of 10.25 percent senior secured second lien notes (the "**Second Lien Notes**") due December 15, 2015, at a price of 98.657 percent, resulting in gross proceeds of approximately US$592 million (approximately $592 million). A portion of the proceeds was used to discharge Connacher's outstanding indebtedness, to fund a one-year debt service reserve account and to pay certain expenses associated with the issuance of the Second Lien Notes. The balance of approximately $327 million was added to the Corporation's working capital to fund the construction of the Algar Project.

Coincidental with the sale of the Second Lien Notes, Connacher secured a new syndicated five year term revolving first lien credit facility (the "**Revolving Facility**"). The Revolving Facility was comprised of a $150 million tranche and a US$50 million tranche, with the latter for use in the business of the Refinery. In March 2009, the Corporation cancelled the Revolving Facility.

Throughout 2007, a total of 1,518,267 stock options were exercised, resulting in the Corporation receiving cash proceeds of $1,466,000. In addition, 108,975 Common Shares were issued in 2007 pursuant to the Corporation's share award incentive plan for non-employee directors.

On February 25, 2008 the Corporation entered into a pooling arrangement totalling 38.5 gross sections of oil sands leases in the Halfway Creek area with Alberta Oilsands Inc., an arm's length party. Under this arrangement, 15.5 sections of undeveloped and prospective lands were contributed by the Corporation and 23 sections were contributed by Alberta Oilsands Inc. The pooling arrangement provides for the joint ownership, evaluation and potential development of any resources which may be identified on the subject leases. The agreement provides for joint operatorship during the initial two years of the evaluation program, with Connacher as the designated operator of any subsequent evaluation program(s) and of any identifiable development program(s) which may occur. In 2008, a decision was made to defer exploration expenditures at Halfway Creek until the 2009-2010 drilling season, when Connacher would be the operator.

Connacher determined that Pod One achieved commerciality effective March 1, 2008. As a result, production, revenues and related expenses were booked in the Corporation's statements of operations and retained earnings from March 1, 2008 onward. Prior thereto, all revenues and expenses related to Pod One were capitalized.

In the winter of 2008, Connacher completed an extensive and successful 125 core hole drilling and 3D seismic program, focused on its main lease block at Great Divide. The results of the drilling program were reflected in the Corporation's June 30, 2008 reserve report by GLJ, which showed a significant increase in reserve volumes and pre-tax present values as compared to the year end 2007 reserve report.

In July 2008, the Corporation's production at Great Divide Pod One surpassed 1 MMbbl of bitumen. During 2008, an aggregate of 2.14 MMbbl of bitumen was produced at Pod One and by year end 2008, total production since start-up was 2.16 MMbbl of bitumen.

In November 2008, Connacher was granted an Order in Council and final approval from the ERCB to proceed with construction of the Algar Project. Subsequent to the issuance of these formal approvals, Connacher advanced its construction program at Algar, but construction was suspended in late December 2008 due to adverse financial, credit and economic market conditions and a decision to preserve cash and credit during a time of economic uncertainty. Notwithstanding the suspension of construction, certain activities, including building of long-lead order equipment and civil work at the Algar plant site and SAGD well pad sites, continued into 2009, to attempt to avoid the possibility of prolonged delays in the project's overall timeline. Construction at Algar and drilling of the 17 SAGD well pairs was reinstated in July 2009.

In November 2008, the Corporation completed the monetization of its US$300 million cross currency and interest swap asset on its US$600 million Second Lien Notes for cash proceeds of $89.1 million. The completion of this transaction and the resultant increase in the Corporation's cash balances were accomplished without cost or equity dilution.

In mid-December 2008, the Corporation announced that a decision had been made to temporarily curtail Pod One production. This decision was taken in response to the then rapid deterioration in the bitumen markets, the emergence of lower crude oil prices, the widening of heavy oil differentials as compared to WTI, a stronger Canadian dollar compared to the relative decline in crude oil prices from peak levels in mid-year 2008, regional marketing issues and some transportation and diluent cost issues. As a consequence, bitumen production at Pod One was reduced to approximately 5,000 bbl/d at the end of December 2008.

Throughout 2008, a total of 1,101,583 stock options were exercised, resulting in the Corporation receiving cash proceeds of $893,000. In addition, 108,975 Common Shares were issued in 2008 pursuant to the Corporation's share award incentive plan for non-employee directors.

On January 21, 2009, Connacher announced the resumption of bitumen production at Pod One due to improved market conditions arising from narrowed heavy oil differentials, improved marketing and transportation arrangements, enhanced diluent blending ratios and improved pricing achieved by locking in higher WTI pricing during a period of pricing contango for a portion of its production during 2009.

During the winter of 2009, a total of 23 gross (23 net) core holes were drilled on the Corporation's Great Divide leases.

In March 2009, Connacher arranged a $20 million demand operating financing facility for the purposes of issuing letters of credit (the "**L/C Facility**"). The L/C Facility was secured by cash and a first lien claim on certain assets of the Corporation.

Also in March 2009, Connacher filed a Proposed Terms of Reference with Alberta Environment with respect to the proposed expansion of its Pod One and Algar SAGD facilities from a combined capacity of 20,000 bbl/d of bitumen to approximately 44,000 bbl/d of bitumen.

In June 2009, Connacher completed a marketed "bought-deal" financing of 191,762,500 Common Shares at a price of $0.90 per Common Share for gross proceeds of $172,586,250. The net proceeds of the offering were used to fund the Corporation's capital expenditures and for general corporate purposes, which included a portion of the capital costs associated with the construction of Algar, after such construction was reinstated in July 2009.

In June 2009, Connacher completed the sale of US$200 million aggregate principal amount of 11.75 percent first lien senior secured notes (the "**First Lien Notes**") due July 15, 2014, at a price of 93.678 percent, resulting in gross proceeds of approximately US$187 million (approximately $212 million). In conjunction with the completion of the debt financing, the Board of Directors of Connacher authorized Management to proceed with the reactivation of construction of Algar. Field construction at Algar was resumed on July 7, 2009. The net proceeds of the debt financing were used for working capital and general corporate purposes, including, together with the net proceeds of the June 2009 equity offering, to fund a portion of the remaining construction, drilling and completion costs associated with the construction of Algar.

In August 2009, Connacher purchased 13,556,000 units of Petrolifera pursuant to a marketed public offering completed by Petrolifera. Each unit was comprised of one common share in the capital of Petrolifera (a "**Petrolifera Share**") and one half of one Petrolifera warrant (each whole Petrolifera warrant being referred to herein as a "**Petrolifera Warrant**"), with each Petrolifera Warrant entitling Connacher to purchase one Petrolifera Share at an exercise price of $1.20 per share at any time on or before August 28, 2011. In the event that the 20-day volume weighted average price of the Petrolifera Shares on the TSX exceeds $2.50, Petrolifera may, within five business days after such an event, provide notice to the holders of Petrolifera Warrants of early expiry and thereafter the Petrolifera Warrants will expire on the date which is 30 days after the date of the notice to the holders of Petrolifera Warrants.

Also in August 2009, the Corporation exercised 200,000 options to acquire Petrolifera Shares. As a result of the acquisition of units and the exercise of options, Connacher owns approximately 22 percent of the Petrolifera Shares.

In October 2009, the Corporation announced officer promotions and new assignments. Mr. Cameron Todd was promoted to the position of Senior Vice President, Operations and was made responsible for all of Connacher's oil sands production operations, the Corporation's refining and marketing activity and its health, safety and environment portfolio. Mr. Russ Longley was appointed Vice President, Refining and Conventional Operations and assumed direct head office responsibility for Connacher's refining operations in Great Falls, Montana and continued to oversee Connacher's conventional crude oil and natural gas production. Mr. Merle Johnson was appointed to the position of Vice President, Engineering and assumed responsibility for the Corporation's production, drilling and reservoir engineering functions, with a primary emphasis on the management and development of Connacher's unconventional bitumen properties at Great Divide.

Also in October 2009, Connacher completed a "bought-deal" financing of 23,172,500 flow-through Common Shares at a price of $1.30 per share for gross proceeds of $30,124,250. The gross proceeds from the offering will be used to further delineate and define the Corporation's oil sands properties through the drilling of additional core holes and for conducting a 3D seismic program over Connacher's oil sands properties.

In November 2009, Connacher secured a new two-year US$50 million revolving credit facility (the "**Revolving Credit Facility**") and cancelled the L/C Facility.

Throughout 2009, a total of 579,724 stock options were exercised, resulting in the Corporation receiving cash proceeds of $388,000. In addition, 327,623 Common Shares were issued in 2009 pursuant to the Corporation's share award incentive plan for non-employee directors and 7,200 Common Shares were issued upon the conversion of $36,000 of Debentures.

In January 2010, Connacher commenced its winter drilling program which resulted in the drilling of 68 core holes at Great Divide and 13 core holes at Halfway Creek (6.5 net core holes); the completion of two 3D seismic programs at Great Divide and Thornbury to identify potential oil sands accumulations that could be the target of future core hole programs; and the drilling of eight wells primarily for natural gas in northern Alberta as part of Connacher's conventional drilling program. The drilling of two additional horizontal SAGD well pairs at Pod One which commenced in December 2009 was completed in January 2010. The total budget for the winter drilling program was set at $45 million. The total capital expenditure budget for 2010 is expected to be approximately $256 million.

Trends

The fallout from the worldwide economic crisis that had its roots in late 2007 continued to dominate the early part of 2009. Equity and bank lending markets were virtually shut down, consumer and industrial demand collapsed, consumer confidence plummeted, job losses continued and commodity prices remained weak. In response, governments around the world continued to inject massive amounts of liquidity into the markets through spending programs and financial intervention in efforts to stabilize banking systems and encourage lending, create jobs and restore consumer confidence. As 2009 progressed, evidence of a recovering global economy, led by Asia, began to emerge; stock markets began to rise, equity and debt capital markets reopened, housing price declines and job losses abated, manufacturing increased, commodity prices showed signs of strength and demand forecasts improved. These events, among others, are expected to contribute to a number of trends in 2010 as discussed below.

The recovery in crude oil prices, more than double from 2009 lows, growing demand for crude oil in Asia and India and stunted world supply is expected to lead to a significant pick-up in activity in the Canadian oil sands in 2010 and beyond. Recent announcements from ConocoPhillips/Total SA, Husky Energy Inc./BP PLC, Canadian Natural Resources Limited and ExxonMobil Canada to initiate new or expand current oil sands projects are evidence of increased confidence in the oil sands industry. Other mega-project oil sands announcements could follow. As new monies begin to flow into the oil sands sector, price inflation for steel and services and labour shortages could once again emerge similar to that experienced during 2006 and 2007. This could put expansion economics at risk.

There is an apparent risk aversion on the part of investors and a resulting positive investor bias towards companies in the oil sands with current production, proven ability to construct and operate projects and strong balance sheets. As a result, smaller land or technology based oil sands companies could find it difficult to attract or raise capital to finance their pilot or commercial projects, or compete in a constrained labour environment. This could lead to consolidation in this space.

The recovery in crude oil prices has also brought with it a renewed interest in the Canadian oil sands from state, national and major international oil companies looking for access to oil reserves in countries with stable political environments. With the majority of lands in the Canadian oil sands under lease and dominated by large companies with little appetite for outside partners, these potential oil sands entrants may focus on junior or emerging oil sands companies for partnership or acquisition opportunities. This could become a very important source of capital to such companies.

The price discount of heavy crude oil compared to light crude oil has been at its lowest percentage levels in recent history. This price discount has primarily been driven by the shortage of heavy crude oil in the United States, declining imports from Mexico and Venezuela and lagging production from Canada, coupled with higher demand for heavy crude oil from many US refineries which added conversion capacity in recent years and with the recent opening of a pipeline connecting heavy crude oil production from Western Canada to refining complexes on the US Gulf Coast. This narrow discount is anticipated to continue in the short to medium term.

Consequently, producers of heavy crude oil and oil sands are expected to experience stronger netbacks and economics, which could lead to more heavy oil or oil sands projects. Conversely, narrow heavy crude oil discounts are expected to negatively impact the profitability of refineries. Also, tighter refined product margins resulting from a surplus of European and Asian gasoline production entering the US markets, a reduction in demand for gasoline as consumers reduce travel and purchase more fuel efficient vehicles and as industry demand for diesel and jet fuel remains soft as the economy slowly recovers, are expected to adversely impact the refining industry in North America in 2010 and beyond. A number of large complex refineries in the US have been shut in and more refineries could be shut in or be closed or mothballed in 2010. In order to weather this deterioration, refineries may be forced to reduce or curtail production runs and focus efforts on specialty products and concentrate on customer servicing and marketing efforts.

Technology advances and improvements in drilling practices have opened up unconventional oil and natural gas opportunities, especially in the natural gas shale formations of North America. These shale plays offer the prospect of natural gas wells with very high initial production levels, albeit with high initial capital costs and decline rates, that offer strong economics at prices above the $6.00/Mcf range. Natural gas production from the shale formations, plus the threat of liquefied natural gas imports from Europe and Asia, should limit the price of natural gas in the short to medium term. Natural gas production from conventional activity is expected to decline as producers switch their focus to shale plays, plus the impact of a mature conventional natural gas basin reflecting high decline rates and high incremental costs of finding and development. Technological developments, including multi-stage fracs, have also led to revisiting oil-bearing formations, including the Cardium in Alberta, the Viking and Shaunavon in southwestern Saskatchewan and the Bakken in southeast Saskatchewan.

Consolidation and asset rationalization amongst senior producers in Canada may result in a large number of good quality conventional oil and natural gas assets being available in the marketplace, accessible to those companies with strong balance sheets or access to capital.

Finally, heightened environmental concern and activism continues, advocating that Canada's oil sands are a significant contributor to global warming. The perceived failure of the 2009 Copenhagen Summit brings with it uncertainty as to the direction of public policy regarding greenhouse gas emissions and environmental regulations. While the Canadian and Alberta governments have their own framework for reducing emissions, it is anticipated that Canadian regulations will mirror pronouncements, when issued, by the US.

BUSINESS OF THE CORPORATION

Connacher is an integrated oil company, primarily engaged in the exploration for, and the development, production and marketing of bitumen, dilbit, crude oil and natural gas, the operation of a heavy oil refinery located in Great Falls, Montana and the marketing of associated refined products. The Corporation's principal asset is its 100 percent working interest in approximately 98,000 net acres of oil sands leases. These are primarily situated in the Divide, Thornbury and Quigley regions and include a 50 percent working interest in the Halfway Creek region, all southwest of Fort McMurray, Alberta. The Corporation declared commerciality of its first 10,000 bbl/d SAGD project, Pod One, at Great Divide effective March 1, 2008. The Algar Project, the Corporation's second 10,000 bbl/d SAGD project, is currently under construction and anticipated to be completed in mid-April 2010.

The Corporation also owns conventional producing crude oil and natural gas properties at Battrum, Saskatchewan and at Marten Creek, Gilby/Three Hills and Latornell, Alberta. The Corporation also holds an approximate 22 percent equity interest in Petrolifera, a public Canadian crude oil and natural gas production, exploration and development company active in Argentina, Peru and Colombia.

Principal Properties

The following paragraphs describe the Corporation's principal properties. Readers are cautioned that the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Oil Sands

Great Divide and Halfway Creek, Alberta

In this region of northeastern Alberta, the Corporation owns and operates 171.5 gross sections of oil sands leases (152 net sections or 97,248 acres net) and 31.25 gross sections (22 net sections or 14,120 acres net) of petroleum and natural gas rights. A number of bitumen accumulations have been identified on these leases.

The Corporation uses the interpretation of its 3D seismic program and the results of core hole drilling to identify exploitable accumulations or pods. Upon receipt of the requisite results and regulatory approvals, the Corporation uses SAGD technology as its primary method to extract bitumen from oil sands formations located approximately 475 m below the surface in the Corporation's exploration area.

Construction on Pod One commenced in November 2006 and, despite the pressures in the construction sector of the oil sands business at that time, was completed by August 2007, within the planned 300 days. Total cost to complete Pod One was $272 million. After commissioning, the Corporation commenced the sequential injection of steam into SAGD well pairs at Pod One on September 16, 2007. On October 22, 2007, the Corporation announced that it had delivered and sold to market its first truckload of dilbit from Pod One. The Corporation determined that Pod One achieved commerciality effective March 1, 2008. As a result, production, revenues and related expenses have been recorded in the Corporation's statement of operations and retained earnings from March 1, 2008 onward.

In mid-December 2008, the Corporation announced that a decision had been made to temporarily curtail Pod One production. This decision was taken in response to a number of factors including the rapid deterioration in the bitumen prices and markets. As a consequence, bitumen production at Pod One was reduced to approximately 5,000 bbl/d at the end of December 2008.

Full production ramp-up at Pod One was reinstated in late January 2009, concurrent with an improvement in heavy oil differentials, reduction in diluent blending and trucking costs and with hedges put in place to protect against any further commodity price declines. Throughout 2009, however, production ramp-up has been constrained in part arising from the decision to curtail production in the first half of the year, as a result of the installation of ESPs, the completion of the mandatory turnaround in September and due to a number of other anomalous operating issues including power outages, equipment failure and evaporator plugging. Production of bitumen averaged 6,334 bbl/d during 2009, with a daily peak rate measured at approximately 10,000 bbl/d in April 2009. By the end of December 2009, bitumen production was stabilized at rates of 8,000 bbl/d.

Final regulatory approvals for the Algar Project were received in November 2008. Subsequent to the issuance of these formal approvals, the Corporation advanced its construction program at the Algar Project by pre-building certain long lead items, but a decision was made to suspend construction in late December 2008 due to deteriorating market conditions and a decision to preserve cash and credit during a time of economic uncertainty. Road building and other civil projects were advanced in January 2009. Following the completion of certain financing activities, field construction at Algar was resumed in July 2009.

The total cost of the Algar Project is estimated to be approximately $360 million, excluding a $15 million contingency provision. The Corporation anticipates that completion of construction activities at Algar by mid-April 2010. Commissioning of the plant will take 30 days and is expected to commence in mid-April 2010. Connacher completed the drilling of 17 horizontal SAGD well pairs at Algar in December 2009 at a cost of approximately $10 million under budget. The wells are expected to be completed and tied-in to the Algar plant in time for steam circulation to begin after the 30 day Algar plant commissioning. Steam will be circulated in the well bores for approximately 90 days thereafter, before the commencement of bitumen production from the Algar accumulation.

The Corporation continues to make progress on the application for the expansion of plant capacity at Great Divide to 44,000 bbl/d of bitumen production. The expansion area covers the main Great Divide land block and includes Pod One and the Algar Project, each at 10,000 bbl/d. An additional 24,000 bbl/d of facilities would be added to the existing Algar site to meet the area target of 44,000 bbl/d. Public consultation, terms of reference and studies have been completed with the next step being the submission of the EIA documents in the second quarter of 2010. The timing of project approvals would likely not allow construction on the expansion to commence until late 2011 or early 2012.

The Corporation has a pooling arrangement with Alberta Oilsands Inc., an arm's length party, in connection with 38.5 gross sections of oil sands leases in the Halfway Creek area of Alberta. The pooling arrangement provides for the joint ownership, evaluation and potential development of any resources which may be identified on the subject leases. No exploration activities were conducted on these leases in 2009. Connacher is the designated operator of the 2010 evaluation program(s) and of any identifiable development program which may occur. An aggregate of 13 core holes (6.5 net core holes) were drilled at Halfway Creek during the Corporation's 2010 winter drilling program.

Additional core hole drilling and 3D seismic interpretation was completed to further delineate identified accumulations on Connacher's land. The Corporation's first quarter 2010 core hole program resulted in the drilling of 68 core holes at Great Divide and 13 gross core holes at Halfway Creek. This data will be integrated into the existing core hole and seismic database to determine which, if any, pods have sufficient size, aerial extent and requisite reservoir quality to be confirmed or added as projects in addition to Pod One and the Algar Project.

The Connacher GLJ Report estimates the Corporation's 1P, 2P and 3P reserves in this area to be 173,225 Mboe, 379,180 Mboe and 461,672 Mboe, respectively.

Conventional Crude Oil and Natural Gas Assets

Connacher's principal conventional operations are at Marten Creek, Gilby/Three Hills and Latornell in Alberta and at Battrum, Saskatchewan. The Connacher GLJ Report estimates the Corporation's 1P and 2P reserves in this area to be 6,933 Mboe and 9,734 Mboe, respectively.

Marten Creek, Alberta

Marten Creek is a natural gas prone area located almost due west of Great Divide. Natural gas in the region is produced from various relatively shallow zones in the Cretaceous Formation at a depth of approximately 2,000 feet. Daily gross natural gas production at Marten Creek for 2009 averaged 8.0 MMcfpd. The Corporation owns a 86.2 percent interest in approximately 160,480 gross acres (138,283 net acres) and operates 100 percent of its petroleum and natural gas leases in this area. The Corporation has in excess of 2,000 km of two-dimensional, or 2D, seismic data to explore and develop this area. No drilling was conducted at Marten Creek in 2009. Eight wells were drilled by the Corporation in winter 2010. The Marten Creek area is a winter work area and, generally, all work must be completed by the end of March in any given year. The Connacher GLJ Report estimates the Corporation's 1P and 2P reserves in this area to be 3,348 Mboe and 4,771 Mboe, respectively.

Gilby/Three Hills, Alberta

Three Hills is located in southern Alberta, northeast of Calgary. The Corporation owns a 95.5 percent interest in approximately 7,998 gross acres (7,638 net acres) at Three Hills, including a unitized waterflood, and is the operator of this property. At Gilby, the Corporation has interests varying from 30 to 50 percent in approximately 8,144 gross acres (3,432 net acres). These properties produce light gravity crude oil and/or natural gas. Average daily production from Gilby/Three Hills was 630 boepd in 2009. No drilling was conducted at Gilby/Three Hills in 2009. The Connacher GLJ Report estimates the Corporation's 1P and 2P reserves in this area to be 1,130 Mboe and 479 Mboe, respectively.

Latornell, Alberta

Latornell is located in central Alberta, approximately 100 km southeast of Grande Prairie. The Corporation owns a 50 percent interest in approximately 10,418 gross acres (5,209 net acres) and a 100 percent interest in 3,378 acres at Latornell. This property is operated by a private corporation, a former officer of which is also a director of Connacher. No drilling was conducted at Latornell in 2009. This area produces natural gas and natural gas liquids from Cretaceous reservoirs. Average daily production from Latornell (net to Connacher) in 2009 was 180 boepd. The Connacher GLJ Report estimates the Corporation's 1P and 2P reserves in this area to be 300 Mboe and 523 Mboe, respectively.

Battrum, Saskatchewan

The Corporation owns and operates working interests of 100 percent in unitized and non-unitized lands in the Battrum region of southwestern Saskatchewan. The properties produce medium gravity crude oil from three units using waterflooding to enhance oil recovery. For the year ended December 31, 2009, the Corporation's average production from this area was 662 bbl/d of oil. There are presently 56 net producing oil and injection wells in this area, which comprise 13,322 gross acres and 13,309 net acres. Two exploratory wells were drilled and abandoned on these properties in 2009. The Connacher GLJ Report estimates the Corporation's working interest share of 1P and 2P reserves in this area to be 1,746 Mboe and 2,366 Mboe, respectively.

The Refinery

The Refinery is a complex cracking/asphalt refinery located in Great Falls, Montana near the Canadian/U.S. border. It processes approximately 9,500 bbl/d of heavy crude oil and produces approximately 10,000 bbl/d of refined products. The Refinery has a Muse-Stancil complexity rating of 10.0, which indicates the ability of the Refinery to produce a broad range of refined products. The Refinery refines primarily Canadian Bow River crude oil, a heavy crude that is similar to the dilbit being produced at Great Divide. The Refinery produces a full range of transportation fuels, including gasoline, diesel and jet fuel with residual material being converted to asphalt products. The Refinery also captures in its margin a portion of the differential between heavy oil and WTI, resulting in a notional hedge against the impact of heavy oil price differential swings on the Corporation's oil sands operations.

In order to comply with requirements of the U.S. Environmental Protection Agency, during 2008 the Corporation implemented a clean fuels project to allow the Refinery to produce ultra-low sulphur diesel and gasoline ("**ULSD**"). During the first quarter of 2009, the US$20 million ULSD project was completed at the Refinery. Due to the down time required to tie-in the new hydrogen plant to complete this project and as a result of certain operational upsets due to significant cold weather, throughput volumes were lower in the fourth quarter of 2008 and first quarter of 2009 than in other recent quarters. Throughput volumes were also lower in the third quarter of 2009 due to the down time associated with the Refinery's triennial major maintenance and turnaround, which began in mid-September 2009 and was completed in mid-October 2009. Throughout 2009, refinery margins remained challenged due to the rise in the cost of crude oil, the narrowing of light and heavy crude oil differentials, lower refined products demand, including gasoline and diesel and the impact of gasoline imports into the US from Europe and India. The Refinery benefited from strong asphalt prices in 2009, a function of a shortage of asphalt in the US, the trickle-down impact of increased infrastructure spending from government initiatives and the result of the Refinery's efforts as a specialty-asphalt maker.

The Refinery is uniquely positioned because of its close proximity to the markets it serves and its ability to refine heavy Canadian crude, with access to both local and regional markets via trucking and rail outlets that directly service the Refinery on-site. Access to crude oil is provided through the Front Range Pipeline which transports Bow River crude and other Canadian crude supplies directly to the Refinery.

Ownership of Petrolifera

As of the date of this Annual Information Form, Connacher owns an undiluted and unencumbered 22 percent equity interest in Petrolifera. Petrolifera is a publicly traded crude oil and natural gas production, exploration and development company active in Argentina, Peru and Colombia with its common shares and warrants listed for trading on the TSX under the symbol "PDP" and "PDP.WT", respectively.

Petrolifera holds interests in approximately six million acres of petroleum and natural gas rights in eleven on-shore concessions or licenses in Argentina, Colombia and Peru. As of the date hereof, Connacher owns 26,898,859 Petrolifera Shares and 6,778,000 Petrolifera Warrants. Readers should refer to "The Corporation - General Development of the Corporation" for information relating to the terms of the Petrolifera Warrants. Based on the closing trading price of Petrolifera on March 18, 2010 of $0.91, Connacher's ownership of common shares of Petrolifera (excluding common shares issuable upon the exercise of the Petrolifera Warrants) represents a $24.5 million investment. Based on Petrolifera's current public disclosures, Petrolifera anticipates participating in a gross capital expenditure program of approximately $53 million during 2010.

Pursuant to NI 51-101, the Corporation is required to state the Corporation's share of Petrolifera's oil and gas reserves, future net revenue and costs incurred during 2009 separately from its own corresponding reserves data and other oil and gas information. Notwithstanding the equity accounting of the Corporation's investment in Petrolifera, the Corporation has no right or entitlement to the reserves and future net revenue of Petrolifera as a shareholder thereof. Set out in Schedule C to this Annual Information Form is a summary of the Corporation's 22 percent interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2009 as evaluated by GLJ in the Petrolifera GLJ Report and reported by Petrolifera in its Annual Information Form for the year ended December 31, 2009. The Petrolifera GLJ Report was prepared using assumptions and methodology guidelines outlined in the COGE Handbook and in accordance with NI 51-101. The pricing used in the forecast price evaluations is set forth in the notes to the tables. Readers are cautioned that as a result of the exercise of any outstanding Petrolifera Warrants or options of Petrolifera and the issuance by Petrolifera of additional securities, the Corporation's interest in Petrolifera's reserves will decrease, unless the Corporation participates in such issuances of securities.

The attached Schedule C has been prepared based on the publicly disclosed information that is contained in the Petrolifera AIF. For additional information beyond what is set forth in Schedule C reference should be made to the Petrolifera AIF which is posted on SEDAR (www.sedar.com) and is not incorporated by reference in this Annual Information Form.

OIL, NATURAL GAS AND BITUMEN RESERVES AND RESOURCES

Connacher engaged GLJ to prepare a report relating to the Corporation's reserves and resources as at December 31, 2009. The information set forth below relating to the Corporation's reserves and resources constitute forward looking information which is subject to certain risks and uncertainties. See "Forward Looking Information" and "Risk Factors".

Oil, Natural Gas and Bitumen Reserves

Connacher's conventional crude oil, natural gas and natural gas liquids reserves are primarily located in four areas, the Battrum area of Saskatchewan and the Marten Creek, Gilby/Three Hills and Latornell areas of Alberta. Connacher's bitumen reserves are located in the Divide region near Fort McMurray, Alberta. Bitumen reserves have been assigned to Pod One and Algar in the 1P, 2P and 3P categories and to the EIA expansion in the 2P and 3P categories. The Connacher GLJ Report assumed 200 SAGD well pairs for the proved case, 385 SAGD well pairs for the 2P case and 400 SAGD well pairs for the 3P case, with cumulative SORs of approximately 3.2, 3.0 and 2.9 respectively, in each case. The cutoffs used by GLJ were 11 m of net pay for 1P bitumen reserves, 10 m of net pay for 2P bitumen reserves and 9 m of net pay for 3P bitumen reserves.

Set out below is a summary of the crude oil, bitumen, natural gas and natural gas liquids reserves and the value of future net revenue of the Corporation as at December 31, 2009 as evaluated by GLJ in the Connacher GLJ Report. The preparation date of the Connacher GLJ Report is February 3, 2010. The pricing used in the forecast price evaluations is set forth in the notes to the tables.

Possible reserves were only evaluated with respect to the Corporation's bitumen reserves. The Corporation's conventional crude oil, natural gas liquids and natural gas reserves were not evaluated in the possible reserves category.

Under NI 51-101, proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible reserves are 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.

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. The estimated future net revenues contained in the following tables do not necessarily represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the Connacher GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the Connacher GLJ 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.

CONVENTIONAL AND BITUMEN RESERVE VOLUMES
BASED ON FORECAST PRICES AND COSTS(8)

	Light/Medium Crude Oil		Bitumen		Natural Gas		Natural Gas Liquids	
	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (Mbbl)	Net(1) (Mbbl)	Gross(1) (MMcf)	Net(1) (MMcf)	Gross(1) (Mbbl)	Net(1) (Mbbl)
Proved Developed Producing(2)(5)	2,166	1,773	13,609	12,310	22,376	18,652	50	35
Proved Developed Non-Producing(2)(6)	58	34	-	-	3,347	2,819	19	14
Proved Undeveloped(2)(7)	71	51	159,616	129,092	1,601	1,083	15	9
Total Proved(2)	2,295	1,858	173,225	141,402	27,324	22,554	84	58
Total Probable(3)	821	612	205,955	158,175	11,733	9,551	24	16
Total Proved Plus Probable(2)(3)	3,116	2,471	379,180	299,577	39,057	32,105	108	74
Total Possible(4)	-	-	82,492	59,506	-	-	-	-
Total Proved Plus Probable Plus Possible(2)(3)(4)	3,116	2,471	461,672	359,083	39,057	32,105	108	74

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS(8)

(MM$)	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At					Net Unit Value Before Income Tax Discounted at 10%/year	
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%	($/boe)	($/Mcfe)
Proved Developed Producing(2)(5)	585	504	443	395	355	585	504	443	395	355	25.71	4.29
Proved Developed Non - Producing(2)(6)	12	9	7	5	4	12	9	7	5	4	12.65	2.11
Proved Undeveloped(2)(7)	4,033	1,885	1,042	644	427	3,093	1,453	811	505	337	8.06	1.34
Total Proved(2)	4,630	2,398	1,492	1,043	787	3,690	1,996	1,260	905	697	10.14	1.69
Total Probable(3)	8,003	1,800	664	357	237	5,913	1,320	490	267	180	4.14	0.69
Total Proved Plus Probable(2)(3)	12,634	4,198	2,156	1,401	1,024	9,602	3,287	1,750	1,172	878	7.01	1.17
Total Possible(4)	1,429	1,884	1,155	672	392	1,113	1,380	819	941	750	19.41	3.24
Total Proved Plus Probable Plus Possible(2)(3)(4)	14,062	6,083	3,310	2,072	1,416	10,715	4,667	2,569	2,113	1,628	9.02	1.50

FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS(8)

	Revenue(9) (MM$)	Royalties (MM$)	Operating Expenses (MM$)	Capital Costs (MM$)	Abandonment Costs (MM$)	Future Net Revenue Before Income Taxes (MM$)	Income Taxes (MM$)	Future Net Revenue After Income Taxes (MM$)
Total Proved(2)	13,576	2,583	4,104	2,206	52	4,630	941	3,690
Total Proved Plus Probable(2)(3)	36,593	7,876	10,400	5,565	119	12,633	3,031	9,602
Total Proved Plus Probable Plus Possible(2)(3)(4)	38,297	8,677	10,061	5,389	109	14,062	3,348	10,715

FUTURE NET REVENUE BY PRODUCTION GROUP BASED ON FORECAST PRICES AND COSTS(8)

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (MM$)	Net Unit Value	
			($/boe)	($/Mcfe)
Total Proved(2)	Light and medium crude oil (including solution gas and by-products)	57	28.51	4.75
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	65	17.66	2.94
	Bitumen	1,369	9.68	1.69
Total Proved Plus Probable(2)(3)	Light and medium crude oil (including solution gas and by-products)	75	28.03	4.67
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	80	15.24	2.54
	Bitumen	2,001	6.68	1.11

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (MM$)	Net Unit Value ($/boe)	Net Unit Value ($/Mcfe)
Total Proved Plus Probable Plus Possible(2)(3)(4)	Light and medium crude oil (including solution gas and by-products)	75	28.03	4.67
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	80	15.24	2.54
	Bitumen	3,156	8.79	1.46

RECONCILIATION OF COMPANY CONVENTIONAL AND BITUMEN RESERVES BY PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS(8)

The following table sets forth a reconciliation of the changes in Connacher's working interest, before royalties, of light and medium crude oil, bitumen, associated and non-associated natural gas (combined) and natural gas liquids reserves as at December 31, 2009 against such reserves as at December 31, 2008 based on the forecast price and cost assumptions set forth in Note 8.

	Light and Medium Crude Oil			Bitumen			Associated and Non-Associated Natural Gas			Natural Gas Liquids		
	Gross Proved (1)(2) (Mbbl)	Gross Probable (1)(3) (Mbbl)	Gross Proved Plus Probable (1)(2)(3) (Mbbl)	Gross Proved (1)(2) (Mbbl)	Gross Probable (1)(3) (Mbbl)	Gross Proved Plus Probable (1)(2)(3) (Mbbl)	Gross Proved (1)(2) (MMcf)	Gross Probable (1)(3) (MMcf)	Gross Proved Plus Probable (1)(2)(3) (MMcf)	Gross Proved (1)(2) (Mbbl)	Gross Probable (1)(3) (Mbbl)	Gross Proved Plus Probable (1)(2)(3) (Mbbl)
December 31, 2008	2,593	807	3,400	175,463	194,221	369,684	28,540	9,574	38,114	27	11	380
Discoveries	-	-	-	-	-	-	-	-	-	-	-	-
Extensions	-	-	-	-	-	-	229	(229)	-	13	(13)	-
Infill Drilling	-	-	-	-	-	-	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-	571	2,113	2,684	-	-	-
Technical Revisions	52	16	68	79	11,734	11,813	1,954	225	2,179	77	26	103
Acquisitions	-	-	-	-	-	-	1,924	52	244	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-	-	-	-
Economic Factors	(3)	(2)	(4)	-	-	-	-	(3)	(3)	-	-	-
Production	(348)	-	(348)	(2,316)	-	(2,316)	(4,162)	-	(4,162)	(32)	-	(32)
December 31, 2009	2,295	821	3,116	173,225	205,955	379,180	27,324	11,733	39,057	84	24	108

Notes:

(1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deducting royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations, plus the Corporation's royalty interests in reserves.

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

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

(4) "Possible" reserves are 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.

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

(6) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut in, and the date of resumption of production is unknown.

(7) "Undeveloped" reserves are those reserves expected to be recovered from know 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 category (proved, probable, possible) to which they are assigned.

(8) The pricing assumptions used in the Connacher GLJ Report with respect to values of future net revenue (forecast) as well as the inflation rates used for operating and capital costs are set forth below. GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

	Light and Medium Crude Oil	Bitumen	Natural Gas	Natural Gas Liquids	Inflation	Bank of Canada Average Noon Exchange Rate
	WTI Cushing Oklahoma ($US/bbl)	Wellhead Current ($Cdn/bbl)	Alberta Spot ($Cdn/MMBtu)	Edmonton Propane ($Cdn/bbl)	%/year	$US/$Cdn
Forecast						
2010	80.00	51.50	5.96	52.46	2.0	0.950
2011	83.00	53.01	6.79	54.45	2.0	0.950
2012	86.00	54.36	6.89	56.43	2.0	0.950
2013	89.00	57.03	6.95	58.42	2.0	0.950
2014	92.00	60.77	7.05	60.42	2.0	0.950
2015	93.84	62.14	7.16	61.64	2.0	0.950
2016	95.72	63.53	7.42	62.88	2.0	0.950
2017	97.64	64.96	7.95	64.15	2.0	0.950
2018	99.59	66.41	8.52	65.45	2.0	0.950
2019	101.58	67.89	8.69	66.77	2.0	0.950
Thereafter	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.950

(9) Values include processing and other income.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2009 were $54.61/bbl for light and medium crude, $3.90/Mcf for natural gas, and $39.39/bbl for bitumen.

Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to planned infill drilling locations. Such reserves may also relate to wells that have been drilled and not yet tied in because of seasonal access issues, the need for further testing of the wells or construction of pipelines and production facilities for the well.

At December 31, 2009, Connacher's conventional net proved undeveloped reserves of 71 Mbbl of crude oil were located at Three Hills and proved undeveloped reserves of 1,601 MMcf of natural gas were located at Marten Creek, Three Hills and Parker. At Great Divide, proved undeveloped reserves of 159,616 Mbbl of bitumen were assigned by GLJ in the Connacher GLJ Report. All of the Corporation's conventional proved undeveloped reserves and approximately 12 percent of the Corporation's bitumen proved undeveloped reserves are scheduled to be developed within the next two years. The balance of the Corporation's bitumen proved undeveloped reserves will be developed as oil sands plant capacity becomes available.

The following table sets out the volumes of gross proved undeveloped reserves that were first attributed for each of the Corporation's product types for each of the Corporation's most recent three financial years and in the aggregate before that time using forecast prices and costs:

Period	Light and Medium Crude Oil (Mbbl)	Bitumen (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Aggregate Prior to December 31, 2007	315	43,841	-	-
December 31, 2007	-	-	1,098	-
December 31, 2008	266	124,216	2,368	15
December 31, 2009	-	79	-	-

The Connacher GLJ Report estimates the Corporation's probable reserves to be 821 Mbbl of light or medium crude oil, 205,955 Mbbl of bitumen, 11,733 MMcf of natural gas and 24 Mbbl of natural gas liquids. Probable undeveloped reserves relate to wells to be drilled, tied in and brought on-stream in the future. All of the Corporation's probable undeveloped conventional reserves will be developed over the next five years. A significant portion of the Corporation's probable undeveloped bitumen reserves will be developed primarily with the construction, startup and commissioning of the Algar Project.

The following table sets out the volumes of gross probable undeveloped reserves that were first attributed for each of the Corporation's product types for each of the Corporation's most recent three financial years and in the aggregate before that time using forecast prices and costs:

Period	Light and Medium Crude Oil (Mbbl)	Bitumen (Mbbl)	Natural Gas (MMcf)	Natural Gas Liquids (Mbbl)
Aggregate Prior to December 31, 2007	280	40,307	229	-
December 31, 2007	-	76,652	1,830	-
December 31, 2008	-	73,186	1,071	7
December 31, 2009	-	11,734	-	-

Significant Factors or Uncertainties

The Corporation does not anticipate that any important economic factors or significant uncertainties would affect particular components of its reported reserves data. Notwithstanding, a number of factors which are beyond the Corporation's control can significantly affect the Corporation's reserves, including product pricing, royalty and tax regimes, changing operating and capital costs, surface access issues, availability of services and processing facilities and technical issues affecting well performance. See "Risk Factors".

Future Development Costs

The following table sets forth the development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Connacher GLJ Report:

	Total Proved Future Development Costs Using Forecast Dollar Costs (M$)	Total Proved Plus Probable Future Development Costs Using Forecast Dollar Costs (M$)	Total Proved Plus Probable Plus Possible Future Development Costs Using Forecast Dollar Costs (M$)
2010	118	124	130
2011	56	41	163
2012	36	96	459
2013	63	34	57
2014	46	51	73
Total for all remaining years	1,887	5,219	4,507
Total, undiscounted	2,206	5,565	5,389

Future development costs are expected to be funded from a combination of the following: operational cash flow, debt and equity financing and/or farmout arrangements with other companies. The timing of such funding may influence the timing of the developmental work expenditures.

Crude Oil and Natural Gas Properties and Wells

The following table sets forth the number of crude oil and natural gas wells in which Connacher held a working interest as at December 31, 2009:

	Crude Oil		Natural Gas	
	Gross(1)	Net(1)	Gross(1)	Net(1)
Alberta				
Producing	17	15	64	62
Non-producing	1	1	72	69
Saskatchewan				
Producing	37	37	-	-
Non-producing	37	37	9	9
Total(2)	92	90	145	140

Notes:

(1) "Gross Wells" are the total number of wells in which Connacher has an interest. "Net Wells" are the number of wells obtained by aggregating Connacher's working interest in each of its gross wells.

(2) Does not include 34 gross and net bitumen SAGD well pairs.

Of the non-producing wells reflected in the table above, 10 non-producing wells have been assigned reserves in the Connacher GLJ Report. Each of these non-producing wells are expected to be tied-in in the next two years.

Costs Incurred

The following table summarizes the capital expenditures made by Connacher on crude oil, bitumen and natural gas properties for the year ended December 31, 2009:

Property Acquisition Costs (MM$)		Exploration Costs (MM$)	Development Costs (MM$)
Proved Properties	**Unproved Properties**		
-	3	15	36

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Connacher completed during its 2009 financial year:

	Exploratory Wells		Development Wells	
	Gross[1]	**Net[1]**	**Gross[1]**	**Net[1]**
Oil Wells[2]	23	23	-	-
Gas Wells	-	-	-	-
SAGD Wells	-	-	37	37
Suspended Wells	1	1	-	-
Observation Wells	-	-	1	1
Water Source / Disposal Wells	-	-	1	1
Dry Holes	1	1	-	-
Total Completed Wells	25	25	39	39

Notes:

(1) "Gross Wells" are the total number of wells in which Connacher has an interest. "Net Wells" are the number of wells obtained by aggregating Connacher's working interest in each of its gross wells.

(2) Includes 23 (gross and net) oil sands exploration delineation core holes.

In 2010 the Corporation will focus on the completion of Algar. A $256 million capital expenditure program is envisaged for 2010 as set forth below.

	(MM$)
Upstream	
Complete Algar	78
Algar capitalized interest, general and administrative expenses and pre-commercial operations	52
Algar ESP pre-work and facility optimization	8
Cogeneration and sales transfer lines	22
Pod One, including two new SAGD wells, 9 high temperature ESPs/progressive cavity pumps and facility optimization	27
Environmental Impact Assessment application	2
Expand Pod One trucking terminal	4
Exploration program	28
Conventional and head office capital	17
Downstream	
Refinery, including benzene removal project and steam boiler replacement	18
Total	$ 256

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land position as at December 31, 2009:

	Undeveloped Acreage (Acres)	
	Gross[(1)]	**Net**[(1)]
Alberta	184,691	157,385
Saskatchewan	20,505	19,979
Total	205,195	177,364

Note:

(1) "Gross" means the total area of properties in which the Corporation has a working interest. "Net" means the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

The Corporation expects its rights to explore, develop and exploit approximately 41,206 gross (32,365 net) acres of its unproved properties to expire within the next year.

The Corporation engaged Sayer to prepare an independent evaluation of the undeveloped land acreage of the Corporation as at December 31, 2009. In the Sayer Energy Advisors Report a fair value of approximately $11.9 million or approximately $58 per gross acre was assigned to Connacher's non-reserve oil and gas properties, excluding its oil sands acreage. In determining the market value, Sayer based their evaluation on the following factors:

1. The acquisition cost, provided that there have been no material changes in the unproved property, the surrounding properties, or the general oil and gas climate since the acquisition;

2. Recent sales by others of interests in the same unproved property;

3. Terms and conditions, expressed in monetary terms, of recent farm-in agreements related to the unproved properties;

4. Terms and conditions, expressed in monetary terms, of recent work commitments related to the unproved property; and

5. Recent sales of similar properties in the same general area.

Asset Retirement Obligations

The Corporation follows the Canadian Institute of Chartered Accountants' standard on Asset Retirement Obligations to account for and report future asset requirement expenditures. This standard requires liability recognition for retirement obligations associated with long-lived assets, which would include abandonment of oil and natural gas wells, related facilities, compressors and gas plants, removal of equipment from leased acreage and returning such land to its original condition. Under the standard, the estimated fair value of each asset retirement obligation is recorded in the period a well or related asset is drilled, constructed or acquired. Fair value is estimated using the present value of the estimated future cash outflows to abandon the asset at the Corporation's credit-adjusted risk-free interest rate. The obligation is reviewed regularly by Management based upon current regulations, costs, technologies and industry standards. The discounted obligation is recognized as a liability and is accreted against income until it is settled or the property is sold and is included as a component of depletion and depreciation expense. Actual restoration expenditures are charged to the accumulated obligation as incurred.

As at December 31, 2009, the estimated total undiscounted amount required to settle the asset retirement obligations in respect of the Corporation's 352 net producing and non-producing wells and facilities, net of estimated salvage recoveries, was $72.1 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 25 years. The 10 percent discounted present value of this amount is $26 million. Over the next three years, the Corporation expects to incur $2.7 (equivalent to $2.1 discounted at 10 percent) of these expenditures. No asset retirement obligations were booked for the Refinery as the Corporation expects to maintain and operate the Refinery indefinitely.

In the Connacher GLJ Report, well abandonment costs for total proved plus probable plus possible reserves were estimated to be $119 million, undiscounted, and $9 million, discounted at 10 percent. These estimates are in respect of well costs only for wells that been assigned reserves and do not include costs to abandon pipelines and facilities or wells for which no reserves have been assigned, which the Corporation has included in determining its asset retirement obligation. These costs include abandonment of 200 net producing wells. Of the undiscounted future net revenue estimated by GLJ, $3 million of abandonment and reclamation costs relating to facilities have not been deducted.

Tax Horizon

Income earned in Canada is not expected to attract taxes until the Corporation utilizes its accumulated tax pools and loss carry forwards, which exceed $1 billion. Based on anticipated capital spending, which augment the tax pools, the Corporation does not expect to pay Canadian income taxes until approximately 2013. The Corporation's US refining subsidiary is currently cash taxable.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2010 in the Connacher GLJ Report for gross proved reserves and gross probable reserves:

	Light/Medium Crude Oil (bbl/d)	**Bitumen (bbl/d)**	**Natural Gas (Mcf/d)**	**Natural Gas Liquids (bbl/d)**
Total Proved(1)	875	8,550	11,544	71
Total Probable(2)	126	755	234	7
Total Proved Plus Probable(1)(2)	1,001	9,305	11,778	78

Notes:
(1) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(2) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

The following table indicates the volume of working interest production, before royalties, estimated for 2010 from fields considered to be individually important:

	Light/Medium Crude Oil (bbl/d)			**Bitumen (bbl/d)**			**Natural Gas (Mcf/d)**		
	Total Proved(1)	Total Probable(2)	Total Proved Plus Probable(1)(2)	Total Proved(1)	Total Probable(2)	Total Proved Plus Probable(1)(2)	Total Proved(1)	Total Probable(2)	Total Proved Plus Probable(1)(2)
Battrum, Saskatchewan	667	118	785	-	-	-	-	-	-
Marten Creek, Alberta	-	-	-	-	-	-	8,575	53	8,628
Great Divide, Alberta	-	-	-	8,550	755	9,305	-	-	-

Notes:
(1) "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
(2) "Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Production History

The following table sets forth certain information in respect of Connacher's production, product prices, royalties, production costs and netbacks received for each quarter of its most recently completed financial year:

	Three Months Ended March 31, 2009	Three Months Ended June 30, 2009	Three Months Ended September 30, 2009	Three Months Ended December 31, 2009
Average Daily Production				
Bitumen (bbl/d)	6,170	6,284	6,551	6,090
Light and Medium Oil (bbl/d)	1,180	1,114	993	880
Natural Gas (Mcfpd)	12,828	12,144	10,377	10,319
Average Net Prices Received				
Bitumen ($/bbl)	22.45	40.95	45.30	48.23
Light and Medium Oil ($/bbl)	39.62	54.87	60.58	67.20
Natural Gas ($/Mcf)	4.89	3.35	2.91	4.34
Royalties				
Bitumen ($/bbl)	0.23	0.16	1.81	1.90
Light and Medium Oil ($/bbl)	10.00	14.12	16.59	12.12
Natural Gas ($/Mcf)	1.20	0.10	(0.83)	(0.09)
Production Costs				
Bitumen ($/bbl)	20.41	14.79	16.92	23.20
Light and Medium Oil ($/bbl)	12.26	9.37	8.51	16.68
Natural Gas ($/Mcf)	2.17	2.33	2.30	2.24
Netback Received				
Bitumen ($/bbl)	(12.35)	0.81	37.26	11.46
Light and Medium Oil ($/bbl)	17.37	31.38	35.48	38.40
Natural Gas ($/Mcf)	1.52	0.92	1.44	2.19

The following table indicates the Corporation's average daily production for the year ended December 31, 2009 from fields considered to be individually important:

	Light/Medium Crude Oil (bbl/d)	Bitumen (bbl/d)	Natural Gas (Mcfpd)
Battrum, Saskatchewan	662	-	-
Marten Creek, Alberta	-	-	8,034
Great Divide, Alberta	-	6,274	-

Competitive Conditions

The petroleum and natural gas industry is competitive in all aspects. Connacher competes with numerous other companies for access to capital to fund its exploration and development activities. It also competes with other companies in the search for exploration and development prospects and in the marketing of its production.

Connacher attempts to enhance its competitive position by:

– focusing on a limited number of core areas;
– maintaining high working interests;
– wherever possible, operating properties;
– securing control over infrastructure such as pipelines, gas processing facilities and its Refinery;
– employing highly competent professional staff who use leading-edge technology; and
– striving to be a low-cost producer.

Bitumen Resources

Currently, in the Great Divide region, proved, probable and possible reserves have been assigned to Pod One and the Algar Project, which have received regulatory approval. Pod One has commenced production.

The Connacher GLJ Report also provided estimates of Contingent Resources associated with identified pods that are outside current areas of production or development. Contingent Resources are those quantities of petroleum estimated, as of 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. There is no certainty that it will be commercially viable to produce any portion of the resources. Contingent Resources were assigned in regions with lower core-hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project application, facility and reservoir design work. Contingent Resources entail additional commercial risk than reserves, which have not been included in the net present valuation. Adjustments for commercial risks have not been incorporated in the summaries of Contingent Resources set forth below.

A range of Contingent Resource estimates (Low, Best and High) were prepared to reflect a range of technical uncertainty. Low Estimate Contingent Resources were assigned to mapped regions of oil-in-place with at least 12 m of continuous bitumen pay along with a conservative estimate of recovery factor. The majority of Low Estimate Contingent Resources were assigned to identified pods outside areas of application. Best Estimate Contingent Resources were assigned to mapped regions of oil-in-place of identified pods outside areas of application for development with at least 10 m of continuous bitumen pay along with a best estimate of recovery factor. High Estimate Contingent Resources were assigned to mapped regions of oil-in-place of identified pods outside areas of application for development with at least 9 m of continuous bitumen pay along with a more optimistic estimate of recovery factor.

The Connacher GLJ Report also provided estimates of Prospective Resources attributable to undiscovered pods. Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. The Prospective Resource estimates set forth below have been risked for the chance of discovery and hence are considered partially risked estimates. Adjustments for commercial risks have not been incorporated in the summaries. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources. Prospective Resources were attributable to undiscovered pods in unexplored regions, utilizing average parameters from the pods discovered to date and the statistical success within the explored regions of the leases. Prospective Resources entail additional commercial and exploration risks than reserves and Contingent Resources, which have not been included in the net present valuation.

A range of Prospective Resources estimates were prepared to reflect a range of technical uncertainty. Best and High Prospective Resource estimates were assigned using net pay thresholds of 10 m and 9 m, respectively. No Low Estimate Prospective resources were assigned, given the risk of not encountering an undiscovered pod of sufficient size to be considered commercial.

BITUMEN RESOURCES

The following table sets out Low, Best and High estimates of the Corporation's Contingent and Prospective bitumen resources which are located in the Divide and Halfway Creek regions, both near Fort McMurray, Alberta:

	Contingent Resources		**Prospective Resources**	
	Total Company Interest (Mbbl)	**Net After Royalty (Mbbl)**	**Total Company Interest (Mbbl)**	**Net After Royalty (Mbbl)**
Low Estimate[(1)]	148,408	120,677	-	-
Best Estimate[(2)]	134,919	111,250	97,142	79,788
High Estimate[(3)]	188,766	151,962	236,786	190,669

Notes:

(1) Low Estimate: this is considered to be a conservative estimate of the quantity that will actually be recovered. It is likely that the actual remaining quantities recovered will exceed the low estimate. If probabilistic methods are used, there should be at least a 90 percent probability that the quantities actually recovered will equal or exceed the low estimate.

(2) Best Estimate: this 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 percent probability that the quantities actually recovered will equal or exceed the best estimate.

(3) High Estimate: this is considered to be an optimistic estimate of the quantity that will actually be recovered. It is unlikely that the actual remaining quantities recovered will exceed the high estimate. If probabilistic methods are used, there should be at least a 10 percent probability that the quantities actually recovered will equal or exceed the high estimate.

BITUMEN RESOURCES AND TOTAL RESERVES

The following table sets out information pertaining to the Corporation's reserves and bitumen resources:

Marketable Reserves and Resources	**Gross Interest**				**Net After Royalty**				**Future Net Revenue - Before Tax Present Value at**		
	Light/Medium Crude Oil (Mbbl)	**Bitumen (Mbbl)**	**Natural Gas (MMcf)**	**NGLs (Mbbl)**	**Light/Medium Crude Oil (Mbbl)**	**Bitumen (Mbbl)**	**Natural Gas (MMcf)**	**NGLs (Mbbl)**	**0% MM$**	**5% MM$**	**10% MM$**
1P Reserves	2,295	173,225	27,324	84	1,858	141,402	22,554	58	4,630	2,398	1,492
2P Reserves	3,116	379,180	39,057	108	2,471	299,577	32,105	74	12,634	4,198	2,156
3P Reserves	3,116	461,672	39,057	108	2,471	359,083	32,105	74	14,062	6,083	3,310
Low Estimate Contingent Resources	-	148,408	-	-	-	120,677	-	-	4,615	835	176
Best Estimate Contingent Resources	-	134,919	-	-	-	111,250	-	-	2,973	1,040	384
High Estimate Contingent Resources	-	188,766	-	-	-	151,962	-	-	4,819	1,545	531
Low Estimate Prospective Resources	-	-	-	-	-	-	-	-	-	-	-
Best Estimate Prospective Resources	-	97,142	-	-	-	79,788	-	-	2,298	712	236
High Estimate Prospective Resources	-	236,786	-	-	-	190,669	-	-	6,333	1,832	610

The estimated future net revenues contained in the foregoing tables do not necessarily represent the fair market value of the Corporation's reserves and resources. Additional information with respect to the Corporation's 1P, 2P and 3P reserves can be found under the heading "Oil, Natural Gas and Bitumen Reserves and Resources - Oil, Natural Gas and Bitumen Reserves" in this Annual Information Form.

DIRECTORS AND OFFICERS

As of the date of this Annual Information Form the name, municipality of residence, positions held with the Corporation and principal occupation during the preceding five years of each of the directors and officers of the Corporation are as set forth below. Each elected director will hold office until the close of the next annual meeting of shareholders of the Corporation, or until his successor is duly elected or appointed.

Name and Municipality of Residence	**Positions Held**	**Principal Occupation During the Preceding Five Years**	**Director Since**
Richard A. Gusella Calgary, Alberta Canada	President, Chief Executive Officer and Director	President and Chief Executive Officer of Connacher since May 2001 and Petrolifera from November 2004 to March 2005. Executive Chairman of Petrolifera since March 2005.	May 30, 2001
D. Hugh Bessell(1)(2)(4) Toronto, Ontario Canada	Director	Independent Businessman. Prior thereto, Deputy Chairman and Chief Operating Officer of KPMG LLP.	December 1, 2005

Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
Colin M. Evans[1][2][4] Calgary, Alberta Canada	Director	President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations since February 2010 and prior thereto from 1990 to 2004. Senior Vice President and previously Vice President, Finance, Milestone Exploration Inc., a private oil and natural gas exploration and production company from September 2004 to February 2010.	April 5, 2004
Stewart D. McGregor[3][7] Calgary, Alberta Canada	Director	President of Camun Consulting Corporation, a private investment holding company, since 1994.	June 12, 2003
W.C. (Mike) Seth[3][4][5] Calgary, Alberta Canada	Director	President, Seth Consultants Ltd., a private consulting firm. Prior thereto, Chairman of McDaniel & Associates Consultants Ltd. and prior thereto, President and Managing Director of McDaniel & Associates Consultants Ltd.	December 9, 2005
Jennifer K. Kennedy[3][5] Calgary, Alberta Canada	Director	Partner, Macleod Dixon LLP, a law firm, since January 2000.	May 12, 2009
Kelly J. Ogle[1][2][5] Calgary, Alberta Canada	Director	President and Chief Executive Officer of Trafina Energy Ltd., an oil and gas company listed on the TSX Venture Exchange, since October 2008. From August 2007 to August 2008, President and Chief Executive Officer of Upper Lake Oil and Gas Ltd., a TSX listed oil and gas exploration and development company. Prior thereto, President of Diamond Tree Energy Ltd., a TSX listed oil and gas company, and Diamond Tree Resources Ltd., a private oil and gas company from October 2004 until October 12, 2007.	May 12, 2009
Peter D. Sametz Calgary, Alberta Canada	Executive Vice President, Chief Operating Officer and Director	Executive Vice President and Chief Operating Officer of Connacher since December 2004.	May 12, 2009
Cameron M. Todd Calgary, Alberta Canada	Senior Vice President, Operations, Refining and Marketing	Senior Vice President, Operations, Refining and Marketing of Connacher since October 2009. Prior thereto, Vice President, Refining and Marketing of Connacher since May 2006. Prior thereto, Vice President, Worldwide Marketing of Pioneer Natural Resources from June 2002 to May 2006.	-
Richard R. Kines Calgary, Alberta Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer since December 2004.	-

Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
Stephen J. De Maio Calgary, Alberta Canada	Vice President, Project Development	Vice President, Project Development of Connacher since November 2006. Prior thereto, Consultant Engineer to in-situ oil sands companies from March 2005. Chief Executive Officer of Efficient Energy Ltd. ("**Efficient Energy**") from December 2000 to March 2005.	-
Merle D. Johnson Calgary, Alberta Canada	Vice President, Engineering	Vice President, Engineering of Connacher since October 2009. Prior thereto, Engineering Manager of Connacher since June 2007. Prior thereto, Development Engineer of EnCana Corporation since November 2001.	-
Russell W. Longley Calgary, Alberta Canada	Vice President, Refining and Conventional Operations	Vice President, Refining and Conventional Operations since October 2009. Prior thereto, Vice President, Operations of Connacher since May 2007. Prior thereto, was instrumental in the start-up, growth and divestment of a private junior exploration gas company.	-
Stephen A. Marston Calgary, Alberta Canada	Vice President, Exploration	Vice President, Exploration of Connacher since January 2006. Prior thereto, Chief Geophysicist of Real Resources Inc. since January 2001.	-
Grant D. Ukrainetz Calgary, Alberta Canada	Vice President, Corporate Development	Vice President, Corporate Development of Connacher since December 2007 and Treasurer of Connacher from June 2006 to February 2008. Prior thereto, Supervisor, Treasury and Treasury and Risk Management Analyst of Talisman Energy Inc. since September 2001.	-
I. Scott Carrothers Calgary, Alberta Canada	Treasurer	Treasurer of Connacher since February 2008. Prior thereto, Manager Corporate Finance with Paramount Resources Ltd. since 2004 and prior thereto, Senior Treasury Advisor and Corporate Finance Advisor with Encana Corporation and Alberta Energy Company Ltd. since 1999.	-
Rashi Sengar Calgary, Alberta Canada	Secretary	Partner, Macleod Dixon LLP, a law firm, since April 2009. Prior thereto, Associate, Macleod Dixon LLP since July 2001.	-

Notes:
(1) Member of the Audit Committee.
(2) Member of the Human Resources Committee.
(3) Member of the Governance Committee.
(4) Member of the Reserves Committee.
(5) Member of the Health, Safety and Environment Committee.
(6) Connacher does not have an Executive Committee.
(7) Lead Director.

As at March 17, 2010, the directors and executive officers of Connacher, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,207,319 Common Shares constituting approximately one percent of the issued and outstanding Common Shares.

No director, officer or shareholder holding sufficient securities of the Corporation to affect materially the control of the Corporation, a personal holding company of any such person, or a company for which such person is or has acted as a director or executive officer that while such person was acting in that capacity, or within a year of the person ceasing to act in that capacity is or has, within the 10 years before the date of this Annual Information

Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such person, except as hereinafter set forth. Colin M. Evans made a proposal involving Canada Revenue Agency under the *Bankruptcy and Insolvency Act* (Canada) on February 24, 2005, which was approved by the Court of Queen's Bench (Alberta) on May 18, 2005. Richard A. Gusella was a director and officer and Kelly J. Ogle was a director of Carmanah Resources Ltd. ("**Carmanah**") until May 2000. A receiver was appointed to hold Carmanah's assets on January 16, 2001, approximately eight months after Messrs. Gusella and Ogle resigned as an officer and director and a director of Carmanah, respectively. Stephen De Maio was an officer and director of Efficient Energy until March 2005. Subsequent to his resignation, in May 2005, a receiver was appointed to hold Efficient Energy's assets.

AUDIT COMMITTEE

Composition and Qualifications

The Corporation's Audit Committee consists of three outside and independent directors namely, Messrs. Bessell, (Chair), Ogle and Evans. The Board has determined that all of the members of the Audit Committee are "financially literate" as defined in National Instrument 52-110. An individual is considered financially literate if he has the ability to read and understand a set of financial statements that present a breadth and complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by the issuer's financial statements. In addition, D. Hugh Bessell has, based upon his experience and educational background, been determined by the Board to be an "audit committee financial expert". The education and experience of each member of the Corporation's Audit Committee relevant to the performance of his responsibilities are as set forth below:

D. Hugh Bessell, Chair

Mr. Bessell is a chartered accountant by training and has an extensive accounting background. He retired as a partner of KPMG LLP in December, 1999 after holding the position of Deputy Chairman and Chief Operating Officer, which position he held for approximately six years. He spent a total of 33 years with KPMG LLP and its predecessor firms, and was Managing Partner of the firm's Calgary office immediately prior to assuming the role of Deputy Chairman in 1993. Mr. Bessell was a member of the Council of the Institute of Chartered Accountants of Alberta and served as its President for a period of time. Mr. Bessell has been granted the FCA designation by both the Alberta and the Ontario Institutes of Chartered Accountants in recognition of his support and contributions to his profession and community. His expertise is particularly important in his capacity as Chairman of the Corporation's Audit Committee and Mr. Bessell has been determined to be an "audit committee financial expert".

Colin M. Evans

Mr. Evans holds a Bachelors Degree in Economics from the University of Alberta and has had an extensive business career in most facets of the oil and gas industry since the mid 1960's. He has worked in positions of increasing responsibility with both large and small private and public companies. He has also worked in the Canadian securities industry and more recently has advised a variety of oil companies on both operational and financial matters. Mr. Evans is currently the President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations, a position he has held since February 2010 and prior thereto from 1990 to 2004. In addition, from September 2004 to March 2010 Mr. Evans held the position of Senior Vice President, Milestone Exploration Inc., a private oil and natural gas exploration and production company.

Mr. Evans served as Chair of the Corporation's Audit Committee from March 23, 2005 to December 1, 2005.

Kelly J. Ogle

Mr. Ogle holds a Bachelors of Arts Degree from the University of Saskatchewan and is currently attending the Directors' Education Program with a view to completing the ICD designation during the spring of 2010. In addition, Mr. Ogle is currently attending the University of Calgary as a Masters Candidate in the Faculty of Military and Strategic Studies.

Mr. Ogle has been involved in the oil and gas industry for the past fourteen years. Mr. Ogle is currently the President and Chief Executive Officer of Trafina Energy Ltd. and has held such position since October 2008. From August 2007 to August 2008, Mr. Ogle was President and Chief Executive Officer of Upper Lake Oil and Gas Ltd., a TSX listed oil and gas exploration and development company. Prior thereto, Mr. Ogle was President of Diamond Tree Energy Ltd., a TSX listed oil and gas company, and Diamond Tree Resources Ltd., a private oil and gas company from October, 2004 until October 12, 2007. Prior thereto, Mr. Ogle was the President and Chief Executive Officer of Ranchgate Energy Inc., then a TSX listed oil and gas company, from January 2003 to August 2004.

Responsibilities and Terms of Reference

The Audit Committee reviews with Management and the external auditors, and recommends to the Board of Directors for approval, the annual financial statements of the Corporation and the reports of the external auditors thereon, the interim financial statements of the Corporation and related financial reporting, including management's discussion and analysis and earnings press releases on the annual and interim financial statements of the Corporation. The Audit Committee reviews and establishes, in conjunction with the external auditors and Management, audit plans and procedures and meets with the auditors independently of Management at each regularly scheduled meeting and otherwise as considered appropriate. The Audit Committee is responsible for reviewing auditor independence, approving all non-audit services, reviewing and making recommendations to the Board of Directors on internal control procedures and management information systems. In addition, the Committee is responsible for assessing and reporting to the Board on financial risk management positions. Set out as Schedule D is the text of the Audit Committee's charter.

All permissible categories of non-audit services require pre-approval from the Audit Committee.

External Auditor Service Fees

The following summarizes the total fees billed by Deloitte & Touche LLP, the external auditor of the Corporation, for the years ended December 31, 2009 and December 31, 2008:

	2009	2008
Audit fees	$ 427,700	$ 252,300
Audit-related fees(1)	470,500	67,800
Tax fees(2)	-	-
All other fees	-	-
TOTAL	$ 898,200	$ 320,100

Notes:

(1) Fees for assurance and related services by Deloitte & Touche LLP in connection with their review of the Corporation's financial statements and not otherwise reported under "Audit Fees". Such services include review engagement fees for the non-audit review of the Corporation's quarterly consolidated financial statements and services related to financings.

(2) Fees for tax compliance, tax advise and tax planning.

Deloitte & Touche LLP are independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

PERSONNEL

As at December 31, 2009, the Corporation had 59 employees at its head office in Calgary, 52 field employees and 94 employees at its Refinery in Great Falls, Montana.

DESCRIPTION OF CAPITAL STRUCTURE

The Corporation is authorized to issue an unlimited number of Common Shares, an unlimited number of first preferred shares and an unlimited number of second preferred shares (together, "**Preferred Shares**"), issuable in series, up to US$200 million aggregate amount of First Lien Notes, up to US$600 million aggregate amount of Second Lien Notes and 100,050 4.75 percent convertible senior unsecured debentures ("**Debentures**"), of which as at December 31, 2009, 427,031,362 Common Shares, no Preferred Shares, US$200 million aggregate amount of First Lien Notes, US$587 million aggregate amount of Second Lien Notes and $100 million aggregate principal amount of Debentures were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares, Preferred Shares, Notes and Debentures.

Common Shares

The holders of Common Shares are entitled to: dividends if, as and when declared by the Board of Directors; to one vote per share at meetings of the holders of Common Shares of the Corporation; and upon liquidation, dissolution or winding up of the Corporation to receive pro rata the remaining property and assets of the Corporation, subject to the rights of shares having priority over the Common Shares. All of the Common Shares currently outstanding are fully-paid and non-assessable.

At the Corporation's annual and special meeting of shareholders held on May 10, 2007 the shareholders of the Corporation adopted a shareholder rights plan (the "**Rights Plan**"), all as described in the material change report of the Corporation dated May 15, 2007. The objectives of the Rights Plan are to ensure, to the extent possible, that all shareholders of the Corporation are treated equally and fairly in connection with any takeover bid or similar offer for all or a portion of the Common Shares of the Corporation. The Rights Plan discourages discriminatory, coercive or unfair takeovers of the Corporation and gives the Board of Directors time if, in the circumstances, the Board of Directors determines it is appropriate to take such time, to pursue alternatives to maximize shareholder value in the event an unsolicited takeover bid is made for all or a portion of the outstanding Common Shares of the Corporation.

In connection with the adoption of the Rights Plan by shareholders, the Corporation issued one right in respect of each Common Share outstanding at the close of business on May 10, 2007 (the "**Record Time**") and authorized the issuance of one right in respect of each additional Common Share issued after the Record Time. The rights trade with and are represented by Connacher's Common Share certificates, including certificates issued prior to the Record Time. Readers may obtain a copy of the Rights Agreement governing the Rights Plan by accessing the Corporation's publicly filed documents, including the Rights Agreement, on SEDAR at www.sedar.com.

Pursuant to the rules of the TSX, the shareholders of the Corporation will be asked to renew the Rights Plan at the annual and special meeting of shareholders of the Corporation scheduled for May 11, 2010. If the shareholders of the Corporation do not approve the renewal of the Rights Plan at such meeting, the Rights Plan will be terminated.

Preferred Shares

The Preferred Shares are issuable in series and each class of Preferred Shares will have such rights, restrictions, conditions and limitations as the Board of Directors may from time to time determine. The holders of Preferred Shares are entitled, in priority to holders of Common Shares, to be paid rateably with holders of each other series of Preferred Shares the amount of accumulated dividends, if any, specified to be payable preferentially to the holders of such series and upon liquidation, dissolution or winding up of the Corporation, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to holders of such series.

First Lien Notes

The First Lien Notes were issued on June 16, 2009 and mature on July 15, 2014. See "The Corporation - General Development of the Corporation". The First Lien Notes bear interest at 11.75 percent per year. Semi-annual interest payments are due January 15 and July 15 of each year, with the final payment on July 15, 2014. The Corporation may redeem up to 35 percent of the aggregate principal amount of the First Lien Notes prior to July 15, 2011 with the net proceeds of certain equity offerings, provided at least 65 percent of the aggregate principal amount of the First Lien Notes remain outstanding after the redemption and subject to limitations contained in the

Corporation's senior secured credit facilities. At any time prior to July 15, 2011, the Corporation may redeem the First Lien Notes in whole or in part at their principal amount, plus the applicable premium and accrued interest. After July 15, 2011, the Corporation may redeem some or all of the First Lien Notes at certain specified redemption prices. The Corporation may also redeem the First Lien Notes in certain other limited circumstances, including in the event of certain tax law changes. The First Lien Notes are general senior obligations, secured by first priority liens on certain specified collateral and rank equally in right of payment with all of the Corporation's existing and future indebtedness that is not subordinated in right of payment of the First Lien Notes, rank senior to all the Corporation's existing and future subordinated indebtedness, unconditionally guaranteed by certain guarantors and are effectively senior to the Second Lien Notes and all existing and future indebtedness that is either secured by liens that rank junior to the liens securing the First Lien Notes or unsecured, with respect to and to the extent of the value of the collateral. The First Lien Notes are effectively subordinated to all of the Corporation's future senior priority lien obligations, to the extent secured by the collateral including the Revolving Credit Facility The First Lien Notes are secured by a first ranking charge over all of the existing and future property of the Corporation and its restricted subsidiaries, excluding the Corporation's equity interest in Petrolifera and the existing assets of Great Divide Pipeline Corporation.

Second Lien Notes

The Second Lien Notes were issued on December 3, 2007 and mature on December 15, 2015. See "The Corporation - General Development of the Corporation". The Second Lien Notes bear interest at 10.25 percent per year. Semi-annual interest payments are due June 15 and December 15 of each year, with the final payment on December 15, 2015. The Corporation may redeem up to 35 percent of the aggregate principal amount of the Second Lien Notes prior to December 15, 2010 with the net proceeds of certain equity offerings, provided at least 65 percent of the aggregate principal amount of the Second Lien Notes remain outstanding after the redemption and subject to limitations contained in the Corporation's senior secured credit facilities. At any time prior to December 15, 2011 the Corporation may redeem the Second Lien Notes in whole or in part at their principal amount, plus the applicable premium and accrued interest. After December 15, 2011, the Corporation may redeem some or all of the Second Lien Notes at certain specified redemption prices. The Corporation may also redeem the Second Lien Notes in certain other limited circumstances, including in the event of certain tax law changes. The Second Lien Notes are general senior obligations and rank equally in right of payment with all of the Corporation's existing and future indebtedness that is not subordinated in right of payment of the Second Lien Notes, rank senior to all the Corporation's future subordinated indebtedness and effectively are subordinated to all existing and future secured indebtedness of the Corporation and of its restricted subsidiaries, including the Revolving Credit Facility and First Lien Notes. See "The Corporation - General Development of the Corporation". The Second Lien Notes are secured by a second ranking charge over all of the existing and future property of the Corporation and its restricted subsidiaries, excluding the Corporation's equity interest in Petrolifera and the existing assets of Great Divide Pipeline Corporation.

Debentures

The Debentures were issued on May 25, 2007. See "The Corporation - General Development of the Corporation". The Debentures mature June 30, 2012 unless converted prior to that date and bear interest at an annual rate of 4.75 percent payable semi-annually on June 30 and December 31. The Debentures are convertible at any time into Common Shares at the option of the holder at a conversion price of $5.00 per Common Share. The Debentures are redeemable by the Corporation on or after June 30, 2010, in whole or in part, at a redemption price equal to 100 percent of the principal amount of the Debentures to be redeemed plus accrued and unpaid interest provided that the market price of the Common Shares is at least 120 percent of the conversion price of the Debentures.

CREDIT RATINGS

The Notes are currently rated by two separate agencies, Moody's Investor Service ("**Moody's**") and Standard and Poors ("**S&P**"). Please refer to the table below for the respective ratings assigned to the Notes.

	Moody's	**S&P**
First Lien Notes	B1	BB-
Second Lien Notes	Caa2	BB-

The Corporation is currently rated by Moody's and S&P. Please refer to the table below for the respective ratings assigned to the Corporation.

Moody's	S&P
Caa1	B

Moody's Rating Definition – Moody's long-term obligation ratings are opinions of the relative credit risk of fixed-income obligations with an original maturity of one year or more. They address the possibility that a financial obligation will not be honoured as promised. Such ratings reflect both the likelihood of default and any financial loss suffered in the event of default. Moody's appends numerical modifiers 1, 2, and 3 to each generic rating classification from Aaa through Caa. The modifier 1 indicates that the obligation ranks in the higher end of its generic rating category; the modifier 2 indicates a midrange ranking; and the modifier 3 indicates a ranking in the lower end of that generic rating category. Investment grade under the Moody's rating system would be Baa3 and higher. Obligations rated Caa are judged to have speculative elements and are subject to substantial credit risk.

S&P Rating Definition – Obligations rated BB, B, CCC, CC and C are regarded as having significant speculative characteristics. BB indicates the least degree of speculation and C the highest. While such obligations likely will have some quality and protective characteristics, these may be outweighed by large uncertainties or major exposure to adverse conditions. An obligation rated BB is less vulnerable to non-payment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation. BB is one notch below that which is considered "Investment Grade" (BBB- and higher) under the S&P rating system. S&P appends + and - modifiers to each generic rating classification from AAA to CCC. The modifier + indicates that the obligation ranks in the higher end of its generic rating category; a rating without a modifier indicates that the obligation ranks in the middle of its generic rating category; and the modifier - indicates that the obligation ranks in the lower end of its generic rating category.

A security rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

PRIOR SALES

The First Lien Notes were sold during the year ended December 31, 2009 at a price of 93.678 percent. See "The Corporation - General Development of the Corporation" and "Description of Share Capital - First Lien Notes". In addition, options to acquire an aggregate of 12,318,375 Common Shares at a weighted average exercise price of $0.96 were issued during the year ended December 31, 2009.

DIVIDEND POLICY

The Corporation has not declared or paid any dividends on its Common Shares since incorporation. Any decision to pay dividends on the Common Shares will be made by the Board of Directors on the basis of the Corporation's earnings, financial requirements and other conditions that the Board of Directors may consider appropriate in the circumstances.

MARKET FOR SECURITIES

The Common Shares are listed and posted for trading on the TSX under the trading symbol "CLL". The following table sets out the high and low price for, and the volume of trading in, the Common Shares on the TSX, as reported by the TSX, on a monthly basis for the financial year ended December 31, 2009.

	Volume	Monthly Price Range High ($)	Monthly Price Range Low ($)
January	25,024,017	1.00	0.68
February	12,447,436	0.96	0.71
March	29,915,289	0.78	0.61
April	65,641,972	1.45	0.74
May	86,304,888	1.66	0.93
June	97,753,156	1.17	0.87
July	29,515,557	0.94	0.76
August	33,633,008	1.06	0.86
September	66,057,530	1.15	0.92
October	73,285,454	1.11	0.94
November	40,938,175	1.07	0.96
December	93,754,485	1.33	1.02

The Debentures are listed and posted for trading on the TSX under the trading symbol "CLL.DB". The following table sets out the high and low price for, and the volume of trading in, the Debentures on the TSX, as reported by the TSX, on a monthly basis from the date of listing to December 31, 2009.

	Volume (000's)	Monthly Price Range High ($)	Monthly Price Range Low ($)
January	5,660	50.00	42.50
February	48,187	46.00	37.00
March	67,440	42.00	35.00
April	379,290	47.75	31.01
May	184,630	65.00	46.10
June	226,550	65.00	56.85
July	29,890	63.49	57.00
August	66,260	75.00	62.00
September	93,785	77.50	72.00
October	94,840	86.50	75.50
November	65,860	87.00	82.75
December	27,350	92.00	85.00

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Connacher Shares and Debentures is Valiant Trust Company at its principal offices in Calgary, Alberta and in Toronto, Ontario.

RISK FACTORS

Risks Relating to Economic Conditions, Commodity Pricing and Exchange Rate Fluctuations

The Corporation's results of operations depend upon the prevailing prices of crude oil and natural gas in the worldwide markets. Those prices are subject to widespread fluctuations.

The Corporation's revenues, cash flow, earnings, cost of capital, asset values, results of operations and financial condition are dependent upon the prevailing price of crude oil and natural gas, heavy oil differentials and the prices of related products that the Corporation produces at the Refinery. These commodity prices are beyond the control of the Corporation. Beginning in July 2008, there was a decline in oil and natural gas prices due, at least in part, to a significant decline in the global economy. The decline in commodity prices adversely affected the

Corporation. Although commodity prices have made marked improvements over the recent months as compared to the lows experienced in the latter part of 2008 and into 2009, any further declines in such prices in the future will adversely affect the Corporation's financial condition and results of operations, cash flows, access to capital markets and ability to grow. The Corporation's financial condition, operating results and future rate of growth depend upon the prices that the Corporation receives for its oil and natural gas. Such prices also affect the amount of the Corporation's cash flow available for capital expenditures and the Corporation's ability to access funds.

The aforementioned significant decline in oil and natural gas prices has adversely impacted the market value and lending value of the Corporation's estimated proved reserves. Sustained low prices or a further decline in such prices could result in a material reduction of the Corporation's operating and financial results, production revenue, reserves and overall value. In addition, any prolonged period of low oil prices could result in a decision by the Corporation to suspend or reduce production. Any such suspension or reduction of production would result in a corresponding substantial decrease in the Corporation's revenues and earnings and could materially impact the Corporation's ability to meet its debt servicing obligations and could expose the Corporation to significant additional expense as a result of any future long-term contracts. If production was not suspended or reduced during such period, the sale of the petroleum products produced by the Corporation at such reduced prices would lower its revenues. There can be no assurance that the conditions in the oil and natural gas industries will improve and that the oil and natural gas prices will increase in the future.

The Corporation conducts an assessment of the carrying value of its assets to the extent required by Canadian Generally Accepted Accounting Principles ("**GAAP**"). If crude oil and/or natural gas prices or the market value of investment holdings decline, the carrying value of the Corporation's assets could be subject to downward revision and its earnings could be adversely affected. Although the Corporation does not currently anticipate any "ceiling test" write downs of its oil and gas assets, or impairment charges to its other assets, there can be no assurance that declines in crude oil prices or other circumstances will not result in such "ceiling test" write downs or impairment charges at some future date.

Crude oil and natural gas prices can fluctuate significantly.

Crude oil prices have historically been extremely volatile and fluctuate significantly in response to regional, national and global supply and demand factors beyond the Corporation's control. Among the factors that can cause crude oil and natural gas price fluctuations are:

- changes in the level of consumer demand for petroleum products and natural gas;
- the domestic and foreign supply of crude oil and natural gas, including the decisions of the Organization of Petroleum Exporting Countries relating to export quotas and their compliance or non-compliance with such self-imposed quotas;
- weather conditions, including hurricanes, floods and other natural disasters;
- domestic and foreign governmental regulations;
- the effect of worldwide conservation of resources;
- new bitumen, crude oil and natural gas discoveries;
- economic growth in developed and emerging nations;
- the price and availability of alternative fuels, including liquefied natural gas;
- political conditions in crude oil and natural gas producing regions, including terrorist activities and other hostilities;
- the proximity of reserves to, and capacity of, transportation facilities;
- the price of foreign imports of crude oil, natural gas and refined products;
- overall global and domestic economic conditions; and

- concern over climate change or emissions of greenhouse gases ("**GHGs**").

Global financial conditions have been subject to increased volatility. This may impact the Corporation's ability to obtain equity, debt or bank financing in the future and may adversely impact its operations.

Current global financial conditions have been subject to increased volatility. Numerous commercial and financial enterprises have either gone into bankruptcy or creditor protection or have had to be rescued by governmental authorities. Recently, access to public financing has been negatively impacted by sub-prime mortgage defaults, the liquidity crisis affecting the asset-backed commercial paper and collateralized debt obligation markets, massive investment losses by banks with resultant recapitalization efforts and requirements and a deterioration in the global economy. These factors may impact the Corporation's ability to obtain equity, debt or bank financing on terms commercially reasonable to the Corporation, if at all. Additionally, these factors, as well as other related factors, may cause decreases in asset values that are deemed to be other than temporary, which may result in impairment losses. If these increased levels of volatility and market turmoil continue, the Corporation's operations could be adversely impacted and the trading price of its securities could continue to be adversely affected.

Banks have been adversely affected by the recent worldwide economic crisis and have severely curtailed existing liquidity lines, increased pricing and introduced new and tighter borrowing restrictions to corporate borrowers, with extremely limited access to new facilities or for new borrowers. These factors could negatively impact the Corporation's ability to access liquidity needed for its business in the longer term. The Corporation may be unable to maintain a level of cash flow from operating activities sufficient to permit the Corporation to pay the principal, interest and premium, if any, on the Corporation's indebtedness.

In addition, certain of the Corporation's customers could experience an inability to pay the Corporation, in the event they are unable to access the capital markets to fund their business operations.

The Corporation is subject to foreign currency exchange fluctuation exposure.

Revenue received from the sale of crude oil is generally referenced to a price denominated in U.S. dollars. The majority of the Refinery's business is conducted in U.S. dollars. Additionally, the Notes are denominated in U.S. dollars and interest payable thereon is denominated in U.S. dollars. As the Corporation reports its operating results, as contained in its balance sheet, statement of comprehensive income (loss) and statement of cash flows, in Canadian dollars, fluctuations in product pricing and fluctuations in the rate of exchange between the U.S. dollar and Canadian dollar would affect, and could result in a material change in, reported results.

The Corporation has issued U.S. dollar denominated debt.

Interest and principal payments on the Notes must be made in U.S. dollars. If the Canadian dollar weakens with respect to the U.S. dollar, the Canadian dollar cost of these payments will increase.

The Corporation may engage in hedging activities which have a negative impact on earnings and cash flow.

The Corporation continually evaluates the use of and often employs exchange-traded or over-the-counter derivative structures to hedge commodity, interest rate and foreign exchange risk. Risks associated with such products include, but are not limited to, counterparty risk, settlement risk, basis risk, liquidity risk and market risk which could impair or negate the Corporation's hedging strategy and result in a negative impact on its earnings and cash flow.

Due to the uncertain worldwide economic environment, there can be no assurance that the Corporation will be able to engage credit worthy counterparties in hedging activities with it.

Risks Relating to the Great Divide Pod One Project and Algar Project

Pod One is operational but there remains a risk that the Corporation may have interruptions or reductions of operations or increased costs. Algar is anticipated to commence operations in 2010 and will be subject to the same risks as Pod One.

Pod One was declared commercial effective March 1, 2008, but there remains a risk that the Corporation may experience interruptions or reductions of operations, increased costs or decreased margins due to many factors, including, without limitation:

- prevailing commodity prices or other economic factors resulting in uneconomic operations;
- facility performance falling below expected levels of output or efficiency;
- breakdown or failure of equipment or processes;
- reservoir performance;
- errors in construction or design affecting operations;
- labour disputes, disruptions or declines in productivity;
- increases in materials, services, transportation or labour costs;
- non-performance by, or financial failure of, third-party contractors;
- disruption or delays in availability of transportation services;
- energy supply disruption;
- conditions imposed by regulatory approvals;
- increased royalty payments based on the price of WTI or further changes to royalty regimes;
- shortages of, or delays in, accessing required equipment and services;
- permit requirement violation;
- transportation or operations accidents;
- delays induced by weather; and
- catastrophic events such as fire, earthquakes, storms or explosions.

Algar is anticipated to commence commercial operations in 2010 following commissioning, steam circulation and start-up. During start-up and thereafter, there is a risk that the Algar Project may experience interruptions or reductions in operations, increased costs and decreased margins based on the factors described above. If any of the above events occur, it could have a material adverse effect on the Corporation's business, financial condition and results of operations.

If the Corporation's Pod One and/or Algar SAGD facilities do not operate as planned, the Corporation's revenue, cash flow and earnings may be reduced.

The performance of the Corporation's Pod One and Algar SAGD facilities may differ from the Corporation's expectations. The variances from the Corporation's expectations may include, without limitation:

- the ability to operate at the expected level of throughput or production;
- the ability to realize the expected long-term SORs; and

- the reliability or availability of the facilities.

If the facilities do not perform to the Corporation's expectations or as required by regulatory approvals, the Corporation may be required to invest additional capital to correct deficiencies or the Corporation may not be able to produce the expected level of production. If these expectations are not met, the Corporation's revenue, cash flow and earnings could be reduced.

The operating costs of Pod One may vary considerably during the operating period and the operating costs of Algar may vary considerably during start-up and thereafter during the operating period. If they increase, the Corporation's earnings and cash flow may be reduced.

The operating costs of Pod One may vary considerably during the operating period. If such costs increase, the Corporation's earnings and cash flow will be reduced. The factors which could affect operating costs include, without limitation:

- the cost of natural gas and electricity;
- the actual steam to oil ratio required to operate the SAGD well pairs;
- the amount and cost of labour to operate Pod One and Algar;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing erosion, hot spots and corrosion;
- reliability of the facilities;
- the maintenance costs of the facilities;
- well performance and pump life;
- workovers or the need to drill additional wells and rig availability;
- the cost to transport bitumen, diluent and dilbit and the cost to dispose of certain by-products;
- the cost of insurance and the inability to insure for certain types of losses;
- catastrophic events such as fires, earthquakes, storms or explosions;
- the cost of catalyst and chemicals; and
- the cost of complying with regulatory approvals.

The selling price received for bitumen produced at Great Divide may vary considerably during the operating period. If certain factors that adversely influence bitumen pricing increase, the Corporation's earnings and cash flow will be reduced. These factors may include, separately or collectively:

- the heavy oil differential;
- the cost of diluent;
- the cost to transport diluent;
- the operation of and access to proximate upgraders;
- the dilbit quality differential; and
- the cost to transport dilbit.

In addition, the absolute price of crude oil prices, as measured by WTI, and U.S./Canadian foreign exchange rates will influence the selling price of bitumen received by the Corporation. A low WTI price and a strong Canadian dollar would negatively impact earnings and cash flow of the Corporation.

Access to diluent supplies at favourable prices may be limited.

Bitumen is characterized by high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the processing and transportation of bitumen. A shortfall in the supply of diluent may cause its cost to increase or alternative diluent supplies to be purchased, thereby increasing the cost to transport bitumen to market and correspondingly increasing the Corporation's operating cost and negatively impacting the overall profitability of Great Divide.

In-situ extraction is subject to uncertainty.

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas or other fuels in the production of steam which is used in the recovery process. The amount of steam required in the production process can also vary and impact costs. The quality and performance of the reservoir can also impact the timing and levels of production using this technology. Commercial application of this technology for bitumen is relatively new, and accordingly in the absence of long-term operating history there can be no assurances with respect to the sustainability of SAGD operations.

The recovery of bitumen from oil sands is subject to a number of risks and uncertainties, many of which are outside of the Corporation's control.

Recovering bitumen from oil sands involves particular risks and uncertainties. Severe weather conditions can cause reduced production and in some situations result in higher costs. SAGD bitumen recovery facilities and development and expansion of production can entail significant capital outlays. Equipment failures could result in damage to the Corporation's facilities or wells and liability to third parties against which the Corporation may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons.

Abandonment and reclamation costs relating to Great Divide may be higher than anticipated.

The Corporation will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of Pod One and Algar and reclamation of its lands at the end of its economic life, the cost of which may be substantial. A breach of such legislation and/or regulations may result in the imposition of fines and penalties, including an order for cessation of operations at the site until satisfactory remedies are made. It is not possible to estimate reliably the abandonment and reclamation costs since they will be a function of regulatory requirements at the time and the value of the salvaged equipment may be more or less than the abandonment and reclamation costs. In the future the Corporation may determine it prudent or be required by applicable laws or regulations to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs.

Transportation to and from Great Divide is subject to certain hazards.

The Corporation expects that it will initially truck bitumen to market. Normal hazards associated with trucking include proximity to a busy highway (Highway 63) and traffic. The Corporation anticipates that vehicular traffic to and from Pod One will be via Highway 63. Collisions between vehicles and wildlife remain a significant hazard.

The Corporation may also use rail or pipelines to transport dilbit to the market and diluent to Pod One. Normal hazards associated with transportation by rail include collisions with vehicles and wildlife and rail line breaks.

Future pods at Great Divide, including the completion of the Algar Project, may be subject to delay due to commodity price declines and credit and capital market conditions, regulatory approvals and economic downturns. These expansion pods may not be completed on time, on budget or at all and once operational, may be subject to delays, interruptions or increased costs that may materially adversely affect the Corporation's results of operations.

Future pods at Great Divide, including Algar, will be subject to construction stage and financing risks. Additionally, there is a risk that future operations, including expansion of production at Great Divide, may have delays, interruption of operations or increased costs due to many factors, including, without limitation:

- prevailing commodity prices or other economic factors resulting in uneconomic operations;
- shortages of, delays in, and increasing costs for obtaining qualified labour, equipment, construction materials or services;
- labour disputes, disruptions or declines in productivity;
- changes in the scope of the project or increases in the amount or cost of materials or labour;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third party contractors;
- breakdown or failure of equipment or processes;
- delays in obtaining, or conditions imposed by, regulatory approvals;
- an inability to obtain adequate financing, or financing on terms satisfactory to the Corporation;
- transportation or construction accidents, disruption or delays in availability of transportation services or adverse weather conditions affecting construction or transportation;
- unforeseen site surface or subsurface conditions;
- disruption in the supply of energy; and
- catastrophic events such as fires, earthquakes, storms or explosions.

The Corporation's development and operation of any additional pods at Great Divide, including Algar, and the Corporation's proposed expansion of Algar will be subject to substantially all of the same risks as those set forth in this Annual Information Form for Pod One in general.

Prior to the recent deterioration in the economy and resulting determinations to delay, defer or suspend future oil sands development by various oil sands owners, the industry was in a period of unprecedented oil sands development and high industrial activity. For example, the Corporation experienced cost overruns in connection with the development of Pod One, which the Corporation believed to be modest in light of inflationary pressures and in comparison to the relative cost pressures faced by other oil sands operators in this area during this time. The Corporation's expansion projects will need to compete for equipment, supplies, services, and labour in this environment, which could result in increased costs or, shortages of goods and services that delay progress, or both.

In addition, participation in expansion projects will significantly increase the demands on the Corporation's Management and administrative resources and require significant financing. The Corporation may not be able to effectively manage or finance the expansions and any failure to do so could have a material adverse effect on the Corporation's business, financial condition or results of operations. Additionally, financing required to fund these expansion projects may not be available on terms and conditions acceptable to the Corporation or at all. See "Risk Factors-Risks Related to Financing and the Corporation's Indebtedness".

Risks Relating to the Corporation's Oil Sands and Conventional Operations

The Corporation must obtain and maintain regulatory approvals and comply with stringent environmental laws and regulations. The failure to obtain such approvals and comply with any of these laws and regulations could, among other things, prevent or limit the Corporation's operations or subject the Corporation to substantial liability, which, in turn, could have a material adverse effect on the Corporation's business and financial condition.

The operation and eventual decommissioning of the Corporation's projects and operations, as well as the construction of future phases of the Corporation's oil sands projects, the development of additional projects and reclamation of the lands used in the Corporation's operations, are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance such approvals will be issued, or once issued, not repealed, or renewed, or that they will not contain terms and conditions which make the Corporation's projects and operations uneconomic or cause the Corporation to significantly alter its projects and operations. Further, the development, operation and eventual decommissioning of the Corporation's projects and reclamation of the Corporation's lands are and will be subject to approvals, laws and regulations relating to environmental protection and operational safety. Risks of substantial costs and liabilities are inherent in both oil sands and conventional oil and natural gas production recovery and there can be no assurance that substantial costs and liabilities will not be incurred or that the Corporation's projects or conventional operations will be permitted to carry on operations. Moreover, it is possible that other developments, such as increased levels of royalties or increasingly strict environmental and safety laws, regulations and enforcement policies thereunder and claims for damages to property or persons resulting from the project's operations could result in substantial costs and liabilities to the Corporation or delays to, or abandonment of, the Corporation's projects and operations, including Pod One and Algar.

No assurance can be given that future environmental approvals, processes, laws or regulations will not adversely impact the Corporation's ability to develop, operate or expand its operations or increase or maintain its production or will not increase the Corporation's unit costs of production for crude oil, natural gas and bitumen. 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, or GHGs. The Corporation will be a producer of some GHGs covered by the Convention as a result of Pod One. On April 26, 2007, the Canadian Federal Government released a *Regulatory Framework for Air Emissions* (the "**Framework**"), which outlines proposed new requirements governing the emission of GHGs and other industrial air pollutants, including sulphur oxides, volatile organic compounds, particulate matter, and possibly additional sector specific pollutants, in accordance with the Canadian Federal Government's *Notice of Intent to Develop and Implement Regulations and Other Measures to Reduce Air Emissions* released on October 19, 2006. On March 10, 2008, the Canadian Federal Government elaborated on the Framework with the release of its *Turning the Corner* policy document. It is unknown if or when new regulations will be released or take effect.

The Framework, together with the Canadian Federal Government's *Turning the Corner* policy document released in March 2008, introduces further, but not full, detail on new GHG and industrial air pollutant limits and compliance mechanisms that will apply to various industrial sectors, including the oil sands extraction, upgrading and electricity production industries starting in 2010. The Canadian Federal Government is in the process of consulting stakeholders about the emission intensity reduction targets which are contemplated to form the basis of new draft regulations. The proposed compliance mechanisms include fixed emission caps and an emissions credit trading system for certain industrial air pollutants, and several options for companies to choose among to meet GHG emission reduction targets and encourage the development of new emission reduction technologies, including the option of making payments into a technology fund, an emissions trading system, and limited credits for emission reductions created between 1992 and 2006.

Future federal industrial air pollutant and GHG emission reduction targets, together with provincial emission reduction requirements in Alberta's *Climate Change and Emissions Management Act*, or emission reduction requirements in future regulatory approvals, may require the reduction of emissions or emissions intensity from the Corporation's operations and facilities, payments to a technology fund or purchase of emission reduction or off-set credits. The required emission reductions may not be technically or economically feasible to implement for Pod One or the Corporation's conventional oil and natural gas activities and the failure to meet such emission reduction requirements or other compliance mechanisms may materially adversely affect the Corporation's business and result in fines, penalties and the suspension of operations. As well, equipment from suppliers which can meet future emission standards may not be available on an economic basis and other compliance methods of reducing emissions or emission intensity to required levels in the future may significantly increase our operating costs or reduce output of our projects. Emission reduction or off-set credits may not be available for acquisition by our projects or may not be available on an economic basis. There is also the risk that the provincial government could impose additional emission or emission intensity reduction requirements, or that the federal and/or provincial governments could pass legislation which would tax such emissions.

To operate the facilities Great Divide relies on non-potable subsurface water, which is obtained under licenses from Alberta Environment. There can be no assurance that the licenses to withdraw subsurface water will not be rescinded or that additional conditions will not be added to these licenses. There can be no assurance that the Corporation will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. In addition, the expansion of the Corporation's projects rely on securing licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favourable to the Corporation or at all, or that such additional water will in fact be available to divert under such licenses.

The Corporation's business may suffer in the event of a loss of key personnel.

The Corporation faces numerous risks due to the stage of its development, as well as certain other factors. The Corporation's success will depend in part on the ability, expertise, judgment, discretion and good faith of the Corporation's Management and its ability to retain them. The Corporation does not maintain key-man life insurance with respect to any of its employees. The loss of any key personnel may have a material adverse effect on the Corporation's business, financial condition or results of operations.

The Corporation's oil and gas operations are subject to numerous operational hazards and other risks against which the Corporation may not be insured.

The operation of Pod One and Algar and the Corporation's conventional oil and gas properties will be subject to the customary hazards of recovering, transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, blowouts and oil spills. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The Corporation's operations could be interrupted by natural disasters or other events beyond its control. Losses and liabilities arising from uninsured or under insured events could have a material adverse effect on the Corporation's business, financial condition and results of operations.

The labour force is limited and the Corporation may not be able to hire all of the labour force required at the compensation levels budgeted for or at all.

The labour force in Alberta, and specifically in the Fort McMurray and surrounding area, has at times been limited. The resurgence of activity experienced in the oil sands industry as of late may impact on the Corporation's ability to access the necessary skilled labourers to operate Pod One and the Algar Project, construct expansion projects and to operate and maintain the Corporation's conventional crude oil and natural gas properties could have an adverse affect on the Corporation's development plans. The Corporation competes with other oil sands projects for experienced employees and such competition may impact the availability of employees and/or may result in increases to compensation paid to such employees. In addition, rising personnel costs could result in increases in general and administrative expenses and labour costs which may adversely affect the Corporation's cash flow and earnings.

Title review will be done in accordance with industry standards but will not guarantee title to the Corporation's properties.

The Corporation's oil sands properties were leased from the Crown in Right of Alberta and although title reviews will be done according to industry standards prior to the purchase of most crude oil and natural gas producing properties (excluding properties acquired from the Crown in Right of Alberta) or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Corporation's claim which could result in a reduction of the revenue the Corporation receives. If such were the case, the Corporation's entitlement to the production and reserves associated with such leases could be jeopardized, which could have a material adverse effect on the Corporation's financial condition, results of operations and the Corporation's ability to execute its business plan in a timely manner or at all.

Aboriginal peoples may make claims against the Corporation or its properties.

Aboriginal peoples have claimed aboriginal title and rights to a substantial portion of western Canada. Certain aboriginal peoples have filed a claim against the Government of Canada, the Province of Alberta, certain governmental entities and the regional municipality of Wood Buffalo (which includes the City of Fort McMurray, Alberta) claiming, among other things, aboriginal title to large areas of lands surrounding Fort McMurray, including the lands on which Pod One, Algar and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on the Corporation and Great Divide. The Corporation continues to consult with and work with Aboriginal groups at Great Divide.

Risks Relating to Financing and the Corporation's Indebtedness

The Corporation's overall level of indebtedness represents a large portion of its current capitalization and could constrain its operations.

The Corporation has a significant amount of indebtedness and the Corporation's level of indebtedness could materially and adversely affect it in a number of ways. For example, it could:

- make it more difficult for the Corporation to conduct its operations;
- increase the Corporation's vulnerability to general adverse economic and industry conditions;
- require the Corporation to dedicate a portion of its cash flow from operations to service payments on its indebtedness, thereby reducing the availability of the Corporation's cash flow to fund working capital, capital expenditures and other general corporate purposes;
- limit the Corporation's flexibility in planning for, or reacting to, changes in its business and the industry in which it operates;
- place the Corporation at a competitive disadvantage compared to its competitors that have less debt; and
- limit the Corporation's ability to borrow additional funds on commercially reasonable terms, if at all, to meet its operating expenses and for other purposes.

The Corporation's ability to make scheduled repayments or to re-finance its debt obligations will depend upon its financial and operating performance.

The Corporation's ability to make scheduled repayments or to re-finance its debt obligations will in part depend upon the Corporation's financial and operating performance, which in turn will partially depend upon prevailing industry and general economic conditions which are beyond its control. There can be no assurance that the Corporation's operating performance, cash flow and capital resources will be sufficient to service and/or repay its debt in the future, in which case the Corporation may be required to sell assets to repay its debt, defer capital expenditures or raise additional debt or equity, to the extent available.

If the Corporation is unable to obtain sufficient funding, its ability to expand its operations may be impaired.

Depending on future exploration, development, acquisition and divestiture plans, including additional projects at the Corporation's oil sands properties in the Great Divide and Halfway Creek regions and the operations and capacity of the Refinery, the Corporation may require additional external financing and in the case of expansions of the Refinery and for further oil sands development, the amount of such financing may be significant. The Corporation's ability to arrange such financing in the future will depend in part upon the prevailing capital market conditions, as well as the Corporation's business performance. There can be no assurance that the

Corporation will be successful in its efforts to arrange additional financing on terms satisfactory to the Corporation or at all. If the Corporation obtains additional financing by the issuance of shares from treasury, control of the Corporation may change and existing shareholders may suffer additional dilution.

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 temporarily increase the Corporation's debt levels above industry standards.

The Corporation borrows funds in U.S. dollars.

A significant portion of the Corporation's debt is denominated in U.S. dollars. Fluctuations in exchange rates may significantly increase or decrease the amount of debt recorded on the Corporation's financial statements. The Corporation may employ derivative structures to hedge foreign exchange risk, however, no derivative structure will protect against all fluctuations.

Risks Relating to Reserves and Resources

Undue reliance should not be placed on estimates of reserves and resources, since these estimates are subject to numerous uncertainties. The Corporation's actual reserves could be lower than such estimates.

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and quantities of Contingent and Prospective Resources and future net revenues to be derived therefrom, including many factors beyond the Corporation's control. The reserve, resource and future net revenue information set forth herein represents estimates only. The reserves, resources and estimated future net cash flow from the Corporation's properties have been independently evaluated by GLJ with an effective date of December 31, 2009. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves and resources, timing and amount of capital expenditures, marketability of production, future prices of blended bitumen, crude oil and natural gas, operating costs, well abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves and resources. These assumptions were based on prices in use at the date the relevant evaluations were prepared, and many of these assumptions are subject to change and are beyond the Corporation's control. Actual production and cash flow derived therefrom will vary from these evaluations, and such variations could be material.

Estimates with respect to reserves and resources that may be developed and produced in the future are often based upon volumetric calculations, probabilistic methods and upon analogy to similar types of reserves and resources, rather than upon actual production history. Estimates based on these methods generally are less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations, which may be material, in the estimated reserves or resources.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed commodity prices and operating costs. Market price fluctuations of crude oil and natural gas prices may render uneconomic the recovery of certain grades of bitumen. Moreover, short term factors relating to oil sands resources may impair the profitability of Pod One in any particular period.

The present value of estimated future net revenue referred to herein should not be construed as the fair market value of estimated bitumen, crude oil and natural gas reserves and bitumen resources attributable to the Corporation's properties. The estimated discounted future revenue from reserves are based upon price and cost estimates which may vary from actual prices and costs and such variance could be material. Actual future net revenue will also be affected by factors such as the amount and timing of actual production, supply and demand for bitumen, crude oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

References to "resources," "Contingent Resources" and "Prospective Resources" in this Annual Information Form do not constitute, and should be distinguished from, references to "reserves". Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Contingent Resources are those quantities of petroleum estimated, as of 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 lack of markets. Not all technically feasible development plans will be commercial. The commercial viability of a development project is dependent on the forecast of fiscal conditions over the life of the project. For Contingent Resources the risk component relating to the likelihood that an accumulation will be commercially developed is referred to as the "chance of development." Prospective resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the "chance of discovery." Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components - the chance of discovery and the chance of development. The estimates of Prospective Resources contained in this Annual Information Form have been risked for the chance of discovery and hence are considered partially risked estimates.

The Corporation's cash flow and earnings growth are highly dependent upon the Corporation developing its current reserve base and converting its resource base to reserves and production.

The Corporation's reserves, resources and production and, therefore, the Corporation's cash flow and earnings, are dependent upon the Corporation developing its current reserve and resource base to production and cash flow and discovering or acquiring additional reserves and resources. To the extent that cash flow from operations is insufficient and external sources of capital become limited or unavailable, the Corporation's ability to make the necessary capital investments to maintain and expand its reserves and resources will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves and resources to replace production at commercially feasible costs.

Risks Relating to the Refinery

The Corporation's refining operations and sales are subject to a number of seasonal factors which may impact its financial performance.

The Refinery is subject to a number of seasonal factors which may cause product sales revenues to vary throughout the year. The Refinery's primary asphalt market is paving for road construction, which is predominantly a summer demand. Consequently, prices and volumes for the Corporation's asphalt tend to be higher in the summer and lower in the colder seasons. During the winter, most of the Refinery's asphalt production is stored in tankage for sale in the subsequent summer. Seasonal factors also affect the prices of gasoline, demand for which is generally higher in summer months and distillate and diesel, for which demand is generally higher in winter months. As a result, inventory levels, inventory values, sales volumes and prices can be expected to fluctuate on a seasonal basis.

Refinery operations are subject to numerous operational hazards and other risks against which the Corporation may not be insured. These risks may interrupt operations, damage facilities or personnel, or interrupt cash flow.

The operation of the Refinery will be subject to the customary hazards of transporting and processing hydrocarbons, such as fires, explosions, gaseous leaks, migration of harmful substances, or oil and product spills. As well the Corporation could experience significant loss as a result of catastrophic events such as fire, flood, earthquakes, or storms. A casualty occurrence might result in the loss of equipment or life, as well as injury or property damage. The Corporation will not carry insurance with respect to all potential casualty occurrences and disruptions. It cannot be assured that the Corporation's insurance will be sufficient to cover any such casualty occurrences or disruptions. The Corporation's operations could be interrupted by natural disasters or other events beyond its control. Losses or liabilities arising from uninsured or under insured events could have a material adverse effect on the Refinery and on the Corporation's business, financial condition and results of operations.

The labour force is limited and the Corporation may not be able to hire all of the labour force required at the compensation levels budgeted for or at all.

The Refinery operates in Great Falls, Montana, which has a small population base and a limited supply of skilled labourers and operators. The demographics of the Refinery's labour force are skewed towards those closer to retirement. It may be difficult to find or attract to Great Falls workforce qualified replacements. In addition, rising personnel costs could result in increases in general and administrative expenses and labour costs which may adversely affect the Corporation's cash flow and earnings.

Abandonment costs relating to the Refinery have not been estimated and recorded.

The Corporation has not recorded an asset retirement obligation for the Refinery as it is currently the Corporation's intent to maintain and upgrade the Refinery so that it will be operational for the foreseeable future. Consequently, it is not possible at the present time to estimate a date or range of dates for settlement of any asset retirement obligation related to the Refinery.

The Corporation's volatility of Refinery margins will fluctuate with changes in the supply and demand for refined products and certain other factors.

The Corporation will face certain risks associated with the volatility of refinery margins. Refinery operations are sensitive to wholesale and retail margins for refined products, including asphalt, jet fuel, diesel, gasoline and other products. Margin volatility is influenced by overall marketplace competitiveness, general economic conditions in the areas the Corporation sells products, the operation of other refineries within the Corporation's market area, weather, the cost of crude oil and fluctuations in supply and demand for refined products.

New U.S. government standards on content of refined products may result in substantial capital expenditures to meet environmental regulations.

An initiative of the U.S. Environmental Protection Agency on gasoline has imposed reductions in benzene content, volatility, sulphur, and other parameters. The U.S. Congress is also proposing a number of environmental initiatives related to greenhouse gases and biofuels. These new requirements, other requirements of the *U.S. Federal Clean Air Act*, or other presently existing or future environmental regulations could require the Corporation to expend substantial amounts to permit the Refinery to produce products that meet such requirements.

Risks Relating to Third Parties

The Corporation may be subject to conflicting interests with joint venture partners

Management of the Corporation may attempt to identify industry participants and negotiate transactions whereby other enterprises will join with the Corporation to conduct joint venture activity to develop the Corporation's oil sands properties. Current capital market conditions make this process more challenging and time consuming than under more buoyant economic circumstances, resulting in the Corporation possibly having to bring participants into its planned activities on less attractive terms than might otherwise have been negotiated. There can be no assurances as to the timing or completion of related terms of possible joint venture arrangements.

Joint venture arrangements must be negotiated with third parties who will generally have objectives and interests that may not coincide with Connacher's interests and may conflict Connacher's interests. Unless the parties are able to compromise these conflicting objectives and interests in a mutually acceptable manner, arrangements with these third parties will not be consummated.

In certain circumstances, the concurrence of joint venture partners may be required for various actions. Other parties influencing the timing of events may have priorities that differ from Connacher's, even if they generally share Connacher's objectives. Demands by or expectations of joint venture partners and others may affect Connacher's participation in such projects or its ability to obtain or maintain necessary licenses and other approvals or the timing of undertaking various activities or operations.

The Corporation is subject to third party credit risks through its contractual arrangements.

The Corporation may be exposed to third party credit risk through its contractual arrangements with its current and future joint venture partners that are marketers of its crude oil, bitumen, natural gas, natural gas liquids production and its refined petroleum products. In the event such entities fail to meet their contractual obligations to the Corporation, such failures could have a material adverse effect on the Corporation and its cash flow from operations. In addition, poor credit condition in the industry and of a potential joint venture partner may impact a potential joint venture partner's willingness to participate in a future Connacher capital program.

The Corporation is subject to extensive government regulation. The Corporation may have to expend substantial amounts for compliance with regulations or the Corporation may become liable for failure to comply with regulations.

The oil and gas industry in Canada, including the oil sands industry, operates under Canadian federal, provincial and municipal legislation and regulation governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, income, the exportation of crude oil, natural gas and other products, the use of sub-surface water in the Corporation's operations, as well as other matters. The industry is also subject to regulation by federal, provincial and municipal governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields and mine sites (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing regulations, the implementation of new regulations or the modification of existing regulations affecting the crude oil and natural gas industry could reduce demand for crude oil and natural gas, increase the Corporation's costs and have a material adverse impact on the Corporation.

To date, the Corporation believes Pod One and the Algar Project have received all of the approvals currently required. However, before proceeding with future phases at Great Divide, the Corporation must obtain all required regulatory approvals. The regulatory approval process can involve stakeholder consultation, environmental impact assessments, public hearings and appeals to tribunals and courts, among other things. In addition, regulatory approvals may be subject to conditions including security deposit obligations and other commitments. Failure to obtain regulatory approvals, or failure to obtain them on a timely basis, could result in delays or restructuring of the project and increased costs, all of which could have a material adverse affect on the Corporation. Pod One, Algar and ongoing exploration activity are also subject to periodic inspections by regulatory authorities to ensure the Corporation's compliance with the conditions of regulatory approvals. Negative inspection results may lead to the imposition of fines or penalties or the suspension or rescission of the project's regulatory approvals.

The Corporation's operating cash flow will be directly affected by the applicable royalty regime.

The Government of Alberta receives royalties on production of natural resources from lands in which it owns the mineral rights.

A change in the royalty regime resulting in an increase in royalties would reduce the Corporation's earnings and could make future capital expenditures or the Corporation's operations uneconomic and could, in the event of a material increase in royalties, make it more difficult to service and repay the Corporation's debt. Any material increase in royalties would also significantly reduce the value of the Corporation's associated assets.

The Corporation's operations will depend on infrastructure owned and operated by third parties and on services provided by third parties. Failure by these third parties to provide infrastructure and services required by the Corporation could have a material adverse effect on the Corporation's business and results of operations.

The Corporation depends on certain infrastructure owned and operated or to be constructed by others and on services provided by third parties, including, without limitation, processing facilities, pipelines or rail lines for the transportation of products to the market, natural gas, disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to the Corporation. The failure of any or all of these third parties to supply utilities, services, or in connection with Pod One and subsequent projects including the Algar Project, to construct necessary infrastructure, on a timely basis and on acceptable commercial terms will negatively impact the Corporation's operations and financial results. Generally, the Corporation also depends on third parties to provide numerous services to it in connection with its Refinery and conventional crude oil and natural gas operations, including transportation services, drilling and well services, and the failure of such third parties to provide such services will also negatively impact the Corporation's operations and financial results.

The Corporation plans on trucking diluent to, and dilbit from, Great Divide to markets in the short term and is also investigating rail and pipeline alternatives. The ability to deliver diluent to Great Divide and ship dilbit to markets is dependent on, among other things, access to trucks and drivers, accidents, weather delay and general road conditions. Delays or the inability to deliver diluent to Great Divide or ship dilbit to market could have a negative impact on the Corporation's results of operations and cash flow.

Changes in tax laws may adversely affect the Corporation, Pod One and future expansion phases.

Income tax laws or government incentive programs relating to the oil and gas industry and in particular the oil sands sector may in the future be changed or interpreted in a manner that adversely affects the Corporation, its operations and future expansion plans.

The Corporation's industry is highly competitive and many of its competitors have greater resources than the Corporation does.

The Canadian and international petroleum industry is highly competitive in all aspects, including the exploration for, and the development of, new sources of supply, the acquisition of crude oil and natural gas interests and the distribution and marketing of petroleum products. The Corporation will compete with producers of bitumen, synthetic crude oil blends and other producers of conventional crude oil and natural gas. Some of the conventional producers have lower operating costs than the Corporation is anticipated to have, and many of them have greater resources than the Corporation has. Certain of the Corporation's competitors may have greater resources to source, attract, and retain the personnel, materials and services that the Corporation will require to conduct its operations or to conduct expansions of the Refinery or at Great Divide. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than the Corporation have announced plans to enter the oil sands business and begin production of bitumen, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen or synthetic crude oil and other competing crude oil products in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices of bitumen and, accordingly, the Corporation's results of operations and cash flow.

Risks Relating to the Corporation's Investment in Petrolifera

The Corporation is subject to foreign political, economic and other uncertainties relating to its investment in Petrolifera.

Petrolifera's operations may be adversely affected by changes in government policies and legislation or social instability and other factors which are not within the control of Petrolifera including, among other things, a change in crude oil or natural gas pricing policy, the risks of war, terrorism, abduction, expropriation, nationalization, renegotiation or nullification of existing concessions and contracts, taxation policies, economic sanctions, the imposition of specific drilling obligations and the development and abandonment of fields. In addition, the crude oil and natural gas produced by Petrolifera in Argentina must, unless certain circumstances exist, be sold locally at rates that may not be comparable to international rates.

Petrolifera's results of operation and the value of the Corporation's investment in Petrolifera are subject to political, economic, and other uncertainties, including, but not limited to, expropriation, changes in energy policies or the personnel administering them, currency fluctuations and devaluations, exchange controls and royalty and tax increases. In the event of a dispute arising in connection with Petrolifera's operations in Argentina, Peru or Colombia, Petrolifera may be subject to the exclusive jurisdiction of foreign courts or may not be successful in subjecting foreign persons to the jurisdictions of the courts of Canada or enforcing Canadian judgements in such other jurisdictions. Petrolifera may also be hindered or prevented from enforcing its rights with respect to a governmental instrumentality because of the doctrine of sovereign immunity. Accordingly, Petrolifera's exploration, development and production activities in Argentina, Peru and Colombia could be substantially affected by factors beyond Petrolifera's control, any of which could have a material adverse effect on Petrolifera's results of operations, which would have an impact on the Corporation's results of operations, and on the value of the Corporation's investment.

Current global stock markets have been subject to increased volatility.

Current global financial conditions have been subject to increased volatility and the trading price of Petrolifera common shares has been adversely affected. This market volatility, may cause decreases in values that are deemed to be other than temporary, which may result in impairment losses. If these increased levels of volatility and market turmoil continue, the Corporation could experience permanent declines in the market value of investment holdings which could result in an impairment charge to its earnings.

The Corporation does not control the Board of Directors of Petrolifera, and accordingly Petrolifera may take actions contrary to those desired by Connacher.

The Corporation owns approximately 22 percent of the outstanding common shares of Petrolifera and currently has three representatives, including its Chief Executive Officer, who is also the Executive Chairman of Petrolifera, on the Board of Directors of Petrolifera. The Corporation's ownership is not sufficient to elect a majority of the Board of Directors and the Corporation has no contractual rights related thereto. Additionally, Petrolifera's management is independent of the Corporation's Management with the exception that Richard A. Gusella is Executive Chairman of Petrolifera and Connacher's President and Chief Executive Officer. The directors and officers of Petrolifera have a fiduciary obligation to act in the best interest of Petrolifera. As such, decisions made by the directors and/or officers of Petrolifera may cause Petrolifera to undertake strategies or courses of action that may not be consistent with the Corporation's short or long term objectives.

In addition, if Mr. Gusella is unable to devote his full time and undivided attention to the Corporation's affairs this may have a material adverse effect on the Corporation.

Other Risks Affecting the Corporation's Business

The Corporation is required to adopt International Financial Reporting Standards.

Canadian public companies are required to prepare their financial statements in accordance with International Financial Reporting Standards ("**IFRS**"), as issued by the International Accounting Standards Board (IASB), for fiscal years beginning on or after January 1, 2011. While the Corporation has commenced its IFRS conversion project, completion of the conversion from GAAP to IFRS will require significant time and expense and the Corporation currently operates with a small staff of accounting personnel. As a consequence, additional personnel or contractors may be required to assist the Corporation in the conversion process and access to such qualified personnel may be limited given the mandated adoption of IFRS by all Canadian public companies. In addition, IFRS will result in the adoption of certain new accounting policies relative to GAAP and increased financial statement disclosure as compared to GAAP. The differences between these accounting policies may impact the Corporation's consolidated financial statements and the Corporation's financial position and results of operations. As at the date of this Annual Information Form, the impact of these new accounting policies has not be determined but the evaluation is continuing. Additionally, enhancements or alterations may be required to the Corporation's disclosure controls and internal controls over financial reporting.

Terrorist attacks and the threat of terrorist attacks may have an adverse impact on the oil and gas industry and energy infrastructure.

The long-term impact of terrorist attacks in the United States, such as the attacks on September 11, 2001, and in Canada and the threat of future terrorist attacks on the oil and gas industry and energy infrastructure in general, and on the Corporation in particular, is not known at this time. The possibility that the oil and gas industry and energy infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures which may be taken as a precaution against possible terrorist attacks will result in increased costs to the Corporation's business.

There are potential conflicts of interest to which some of the Corporation's directors and officers will be subject in connection with the Corporation's operations.

Some of the directors and officers of the Corporation are engaged and will continue to be engaged in the search of oil and gas interests on their own behalf and on behalf of other corporations, and situations may arise where the directors and officers will be in direct competition with the Corporation. From time to time, the

Corporation may jointly participate in exploration and development activities with one or more corporations with which a director or officer of the Corporation may be involved. Additionally, the Corporation's President and Chief Executive Officer is also an officer and director of Petrolifera and two of the Corporation's other directors are directors of Petrolifera. These individuals receive compensation from Petrolifera for their services. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the ABCA which require a director or officer of a corporation who is a party to or is a director or an officer of or has a material interest in any person who is a party to a material contract or proposed material contract with the Corporation to disclose his interest and to refrain from voting on any matter in respect of such contract unless otherwise permitted under the ABCA.

LEGAL PROCEEDINGS

There are no material legal proceedings against the Corporation.

INTERESTS OF EXPERTS

Each of Sayer and GLJ have prepared a report or valuation described herein. Neither Sayer nor GLJ held any interests in securities or other property of Connacher when it prepared its respective report or valuation, has received any such interest since such time or will receive any such interest. No director, officer or employee of Sayer or GLJ is to be elected, appointed or employed by Connacher.

ADDITIONAL INFORMATION

Additional information, including information as to directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans, if applicable, is contained in the Management Information Circular of the Corporation prepared in connection with the most recent annual meeting of shareholders of the Corporation that involved the election of directors. Additional financial information is provided in the Corporation's financial statements and management discussion and analysis for the year ended December 31, 2009, which are contained in the Annual Report of the Corporation for the year ended December 31, 2009.

Copies of this Annual Information Form, the Corporation's Annual Report, any interim financial statements of the Corporation subsequent to those statements contained in the Annual Report, the Corporation's Management Information Circular and other additional information relating to the Corporation are available on SEDAR at *www.sedar.com*.

SCHEDULE A

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Connacher Oil and Gas Limited (the "**Company**"):

1. We have prepared an evaluation of the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, 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 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, 2009, 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	February 3, 2010	Canada	-	2,155,582	-	2,155,582

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

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 judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 12, 2010.

(Signed) "Dana B. Laustsen, P.Eng"
Dana B. Laustsen, P.Eng.
Executive Vice-President

REPORT ON RESOURCES DATA

BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Connacher Oil and Gas Limited (the "Company"):

1. We have prepared an evaluation of the Company's resources data as at December 31, 2009. The resources data are estimates of low, best and high estimates of contingent and prospective resources and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the resources 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 resources data are free of material misstatement. An evaluation also includes assessing whether the resources data are in accordance with principles and definitions in the COGE Handbook.

4. The following table sets forth the estimated future net revenue of the Company (before deduction of income taxes) attributed to best estimate contingent resources and best estimate prospective resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, evaluated by us for the year ended December 31, 2009, 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 and Resource Category	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
Contingent Resources						
GLJ Petroleum Consultants	February 3, 2010	Canada	-	383,530	-	383,530
Prospective Resources						
GLJ Petroleum Consultants	February 3, 2010	Canada	-	235,825	-	235,825

5. In our opinion, the resources data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

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 resources data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that resources are categorized according to the probability of their recovery.

8. Contingent resources evaluated in this report were assigned in regions with lower core-hole drilling density than the reserve regions and are outside current areas of application for development. These resource estimates are not classified as reserves at this time, pending further reservoir delineation, project

application, facility and reservoir design work. Contingent resources entail commercial risk not applicable to reserves, which have not been included in the net present valuation. There is no certainty that it will be commercially viable to produce any portion of the contingent resources.

9. Prospective resources were assigned in unexplored regions of the Company's acreage. The prospective resource estimates have been risked for the chance of discovery, hence are considered partially risked estimates. Prospective resources also entail commercial risk not applicable to reserves, which have not been included in the net present valuation. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the prospective resources.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 12, 2010.

(Signed) "Dana B. Laustsen, P.Eng"
Dana B. Laustsen, P.Eng.
Executive Vice-President

SCHEDULE B

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Connacher Oil and Gas Limited (the "**Corporation**") are responsible for the preparation and disclosure of information with respect to the Corporation's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's reserves data. The report of the independent qualified reserves evaluator is presented in Schedule A and will be filed with securities regulatory authorities concurrently with this report.

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

(a) reviewed the Corporation's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

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

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

(b) the filing of Forms 51-101F2 which are the reports of the independent qualified reserves evaluator on the reserves and resources data; and

(c) the content and filing of this report.

Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

(signed) *Richard A. Gusella*
Richard A. Gusella
President and Chief Executive Officer

(signed) *Colin M. Evans*
Colin M. Evans
Director

(signed) *Richard R. Kines*
Richard R. Kines
Vice President Finance and Chief Financial Officer

(signed) *W.C. Seth*
W.C. Seth
Director

March 19, 2010

SCHEDULE C

CONNACHER'S 22 PERCENT INTEREST IN PETROLIFERA'S OIL AND GAS RESERVES AND FUTURE NET REVENUE

The following is a summary of the Corporation's 22 percent interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2009 as evaluated by GLJ in the Petrolifera GLJ Report. The information contained within this Schedule C has been derived from the Petrolifera AIF which is posted on SEDAR (*www.sedar.com*).

SUMMARY OF OIL AND GAS RESERVES[9]

Reserves Category	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross[1] (Mbbl)	Net[1] (Mbbl)	Gross[1] (MMcf)	Net[1] (MMcf)	Gross[1] (Mbbl)	Net[1] (Mbbl)
Proved Developed Producing[2][7]						
Argentina	855	739	1,159	986	26	22
Colombia	-	-	-	-	-	-
Total Proved Developed Producing	855	739	1,159	986	26	22
Proved Developed Non-Producing[2][6]						
Argentina	21	18	7	6	-	-
Colombia	-	-	-	-	-	-
Total Proved Developed Non-Producing	21	18	7	6	-	-
Proved Undeveloped[2][8]						
Argentina	769	663	648	560	15	13
Colombia	-	-	-	-	-	-
Total Proved Undeveloped	769	663	648	560	15	13
Total Proved[2]						
Argentina	1,645	1,420	1,814	1,553	41	35
Colombia	-	-	-	-	-	-
Total Proved	1,645	1,420	1,814	1,553	41	35
Total Probable[3]						
Argentina	1,180	1,021	1,402	1,195	27	23
Colombia	154	140	289	267	-	-
Total Probable	1,334	1,161	1,690	1,462	27	23
Total Proved Plus Probable[2][3]						
Argentina	2,825	2,441	3,216	2,747	69	59
Colombia	154	140	289	267	-	-
Total Proved Plus Probable	2,979	2,581	3,504	3,014	69	59
Total Possible[4]						
Argentina	962	830	2,239	1,901	27	23
Colombia	317	289	596	552	-	-
Total Possible	1,280	1,119	2,835	2,452	27	23
Total Proved Plus Probable Plus Possible[2][3][4]						
Argentina	3,788	3,271	5,455	4,648	96	81
Colombia	471	429	884	819	-	-
Total Proved Plus Probable Plus Possible	4,259	3,700	6,339	5,467	96	81

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE [9]

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At					Unit Value Before Income Tax Discounted at 10%/year	
Reserves Category (M$)	**0%**	**5%**	**10%**	**15%**	**20%**	**0%**	**5%**	**10%**	**15%**	**20%**	**($/boe)**	**($/Mcfe)**
Proved Developed Producing[2][7]												
Argentina	25,136	22,642	20,636	18,992	17,619	24,354	21,892	19,916	18,298	16,950	22.30	3.72
Colombia	-	-	-	-	--	-	-	-	-	-	-	-
Total Proved Developed Producing	25,136	22,642	20,636	18,992	17,619	24,354	21,892	19,916	18,298	16,950	22.30	3.72
Proved Developed Non-Producing [2][6]												
Argentina	593	499	424	364	314	449	365	299	246	204	22.10	3.68
Colombia	-	-	-	-	--	-	-	-	-	-	-	-
Total Proved Developed Non-Producing	593	499	424	364	314	449	365	299	246	204	22.10	3.68
Proved Undeveloped[2][8]												
Argentina	21,759	16,803	13,188	10,494	8,446	14,860	10,931	8,099	6,016	4,456	17.14	2.86
Colombia	-	-	-	-	--	-	-	-	-	-	-	-
Total Proved Undeveloped	21,759	16,803	13,188	10,494	8,446	14,860	10,931	8,099	6,016	4,456	17.14	2.86
Total Proved[2]												
Argentina	47,485	39,943	34,249	29,849	26,380	39,663	33,188	28,314	24,560	21,609	19.98	3.33
Colombia	-	-	-	-	--	-	-	-	-	-	-	-
Total Proved	47,485	39,943	34,249	29,849	26,380	39,663	33,188	28,314	24,560	21,609	19.98	3.33
Total Probable[3]												
Argentina	43,505	30,396	22,136	16,702	12,986	28,430	19,703	14,207	10,597	8,136	17.81	2.97
Colombia	2,634	1,229	211	(532)	(1,075)	2,634	1,229	211	(532)	(1,075)	(1.04)	(0.19)
Total Probable	46,140	31,625	22,347	16,170	11,912	31,064	20,932	14,418	10,065	7,061	15.65	2.61
Total Proved Plus Probable[2][3]												
Argentina	90,990	70,339	56,384	46,550	39,367	68,092	52,891	42,521	35,157	29,745	19.07	3.18
Colombia	2,634	1,229	211	(532)	(1,074)	2,634	1,229	211	(532)	(1,074)	(1.04)	(0.19)
Total Proved Plus Probable	93,624	71,568	56,595	46,019	38,292	70,726	54,120	42,732	34,625	28,670	18.01	3.00
Total Possible[4]												
Argentina	34,898	22,898	15,752	11,283	8,366	22,753	14,661	9,864	6,883	4,953	13.47	2.24
Colombia	21,377	15,257	11,164	8,352	6,372	16,101	11,421	8,300	6,162	4,662	29.30	4.88
Total Possible	56,275	38,155	26,916	19,634	14,737	38,854	26,081	18,164	13,045	9,615	17.36	2.89
Total Proved Plus Probable Plus Possible[2][3][4]												
Argentina	125,888	93,237	72,136	57,833	47,732	90,845	67,552	52,385	42,040	34,698	17.48	2.91
Colombia	24,011	16,486	11,375	7,820	5,297	18,735	12,650	8,510	5,630	3,588	20.11	3.35
Total Proved Plus Probable Plus Possible	149,900	109,723	83,511	65,653	53,029	109,580	80,201	60,895	47,670	38,286	17.80	2.97

TOTAL FUTURE NET REVENUE (UNDISCOUNTED)[9]

Reserves Category (M$)	**Revenue**	**Royalties**	**Operating Expenses**	**Development Costs**	**Abandonment Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes**	**Future Net Revenue After Income Taxes**
Total Proved[2]								
Argentina	98,993	13,602	27,480	9,674	752	47,485	7,822	39,663
Colombia	-	-	-	-	-	-	-	-
Total	98,993	13,602	27,480	9,674	752	47,485	7,822	39,663
Total Proved Plus Probable[2][3]								
Argentina	176,327	24,130	45,848	14,407	953	90,990	22,898	68,092
Colombia	14,760	1,291	1,750	9,033	53	2,634	-	2,634
Total	191,087	25,420	47,597	23,439	1,006	93,625	22,898	70,726
Total Proved Plus Probable Plus Possible[2][3][4]								
Argentina	243,579	33,491	60,342	22,740	1,117	125,888	35,043	90,845
Colombia	46,879	4,113	5,349	13,321	85	24,011	5,276	18,735
Total	290,459	37,604	65,690	36,062	1,203	149,900	40,319	109,580

Notes:

(1) "Gross Reserves" are the Corporation's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation. "Net Reserves" are the Corporation's working interest (operating or non-operating) share after deduction of royalty obligations plus the reporting issuer's royalty interests in reserves.

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

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

(4) "Possible" reserves are 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.

(5) "Developed" reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example when compared to the cost of drilling a well) to put the reserves on production.

(6) "Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production but are shut in and the date of resumption of production is unknown.

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

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

(9) The pricing assumptions used in the Petrolifera GLJ Report with respect to the inflation rates used for operating and capital costs and exchange rates are set forth below and are as at December 31, 2009.

	Inflation Rate	**Exchange Rate**
	%/year	**$US/$Cdn**
Year Forecast		
2010	2.0	0.95
2011	2.0	0.95
2012	2.0	0.95
2013	2.0	0.95
2014	2.0	0.95
2015	2.0	0.95
2016	2.0	0.95
2017	2.0	0.95
2018	2.0	0.95
2019	2.0	0.95
Thereafter		

The crude oil price received by Petrolifera in Argentina is dependent on the price level of WTI and the domestic price of oil in Argentina. The crude oil price received by Petrolifera in Colombia is based on world prices.

Forecast prices assumptions relating to crude oil, natural gas and NGL are as follows:

	Light and Medium Crude Oil		**Natural Gas**		**NGL**
	Argentina Crude Oil Price ($Cdn/bbl)	**WTI Crude Oil Price ($Cdn/bbl)**	**Argentina Gas Price ($Cdn/Mcf)**	**Colombia Gas Price ($Cdn/Mcf)**	**Argentina NGL Price ($Cdn/bbl)**
Year Forecast					
2010	52.50	84.21	2.81	4.74	39.09
2011	53.68	87.37	2.86	4.83	39.92
2012	54.76	90.53	2.92	4.93	40.50
2013	55.85	93.68	2.98	5.03	41.39
2014	56.97	96.84	3.04	5.13	42.22
2015	58.11	98.78	3.10	5.23	43.07
2016	59.27	100.76	3.16	5.34	43.93
2017	60.46	102.78	3.22	5.44	44.81
2018	61.67	104.83	3.29	5.55	45.73
2019	62.90	106.93	3.35	5.66	46.56
Thereafter	2.0%/year	2.0%/year	2.0%/year	2.0%/year	2.0%/year

GLJ is an independent qualified reserves evaluator appointed pursuant to NI 51-101.

The following table summarizes Connacher's share of the capital expenditures made by Petrolifera on oil and natural gas properties for the year ended December 31, 2009:

	Property Acquisition Costs		Exploration Costs (MM$)	Development Costs (MM$)
	Proved Properties (MM$)	Unproved Properties (MM$)		
Argentina	-	-	3.5	2.5
Peru	-	-	1.7	-
Colombia	-	0.2	8.0	-

SCHEDULE D

AUDIT COMMITTEE CHARTER

The Audit Committee (the "**Committee**") of the board of directors (the "**Board**") of Connacher Oil and Gas Limited (the "**Corporation**") shall have the oversight responsibility, authority and specific duties as described below.

Composition

The Committee will be comprised of three or more directors as determined by the Board. Each Committee member shall satisfy the independence, financial literacy and experience requirements of applicable securities laws, rules or guidelines, any applicable stock exchange requirements or guidelines and any other applicable regulatory rules. In particular, each member of the Committee shall have no direct or indirect material relationship with the Corporation which could reasonably be expected to materially interfere with the member's independent judgment. Determinations as to whether a particular Director satisfies the requirements for membership on the Committee shall be made by the full Board and shall be reviewed at least annually.

Members of the Committee shall be appointed from time to time by the Board. Each member shall serve until his successor is appointed, unless he shall resign or be removed by the Board or he shall otherwise cease to be a director of the Corporation. If a member of the Committee ceases to be independent for reasons outside that member's reasonable control, the member shall immediately notify the Chair of the Board as to this fact and shall resign his or her position as a member of the Committee on the earliest of (i) the appointment of his or her successor; (ii) the next annual meeting of shareholders of the Corporation; and (iii) the date that is six months from the occurrence of the event which caused the member to not be independent. The Board shall fill any vacancy if the membership of the Committee is less than three Directors.

The Chair of the Committee may be designated by the Board or, if it does not do so, the members of the Committee may elect a Chair by vote of a majority of the full Committee membership.

Operation

The Committee shall have access to such officers and employees of the Corporation and to the Corporation's independent external auditors, and to such information respecting the Corporation, as it considers to be necessary or advisable in order to perform its duties and responsibilities. The Committee has the authority to engage independent counsel and other advisors as it determines necessary to carry out its duties and to set and pay the compensation for any such counsel and advisors, such engagement to be for the Corporation's sole account and expense.

Meetings of the Committee shall be conducted as follows:

1. The Committee shall meet at least four times annually at such times and at such locations as the Chair of the Committee shall determine, provided that meetings shall be scheduled so as to permit timely review of the quarterly and annual financial statements and reports. The independent auditors or any one member of the Committee may also request a meeting of the Committee.

2. The quorum for meetings shall be a majority of the members of the Committee, present in person or by telephone or by other telecommunication device that permits all persons participating in the meeting to hear each other.

3. The Chair shall, in consultation with management and the external auditors, establish the agenda for the meetings and instruct management to ensure that properly prepared agenda materials are circulated to the Committee with sufficient time for study prior to the meeting.

4. Every question at a Committee meeting shall be decided by a majority of the votes cast.

5. The Chief Executive Officer shall be available to advise the Committee, and may attend meetings at the invitation of the Chair of the Committee. Other management representatives may be invited to attend. The independent external auditors shall be given notice of, and shall be entitled to attend, each meeting of the

Committee at the expense of the Corporation. The Chair of the Committee shall hold in camera meetings of the Committee, without management present, at every regularly scheduled Committee meeting.

6. A Committee member, or any other person selected by the Committee, shall be appointed at each meeting to act as secretary for the purpose of recording the minutes of each meeting.

7. The Committee may delegate from time to time to any person or committee of persons any of the Committee's responsibilities that lawfully may be delegated.

The Committee provides an avenue for communication, particularly for outside directors, with the independent external auditors and financial and senior management and the Board. The independent external auditors shall have a direct line of communication to the Committee through its Chair. The Committee, through its Chair, may contact directly any employee in the Corporation as it deems necessary, and any employee may bring before the Committee on a confidential basis any matter involving financial practices or transactions.

Responsibilities

The Committee is part of the Board. Its primary function is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the preparation and disclosure of the financial statements, and accompanying reports, to be provided to shareholders and regulatory bodies; (ii) the system of internal control and management information systems of the Corporation that management has established; and (iii) the external audit process. In addition, the Committee shall assist the Board as requested in fulfilling its oversight responsibilities with respect to (i) financial policies and strategies; (ii) financial risk management practices; and (iii) transactions or circumstances which could materially affect the financial position or results of operations of the Corporation.

The role of the Committee is one of stewardship and oversight. Management is responsible for preparing the financial statements and financial reporting of the Corporation and for maintaining internal control and management information and risk management systems and procedures. The external auditors are responsible for the audit or review of the financial statements and other services they provide.

The Committee should have a clear understanding with the external auditors that the independent auditors must maintain an open and transparent relationship with the Committee and the Board, and that the ultimate accountability of the external auditors is to the shareholders of the Corporation.

The Committee shall provide the Board with a summary of all meetings by way of an oral report delivered by the Chair of the Committee to the Board. All information reviewed and discussed by the Committee at any meeting shall be referred to in the minutes and made available for examination by the Board upon request to the Chair.

Specific Duties

1. Financial Statements and Financial Reporting.

The Committee shall:

(a) review with management and the external auditors, and recommend to the Board for approval, the annual financial statements of the Corporation, the reports of the external auditors thereon and related financial reporting, including Management's Discussion and Analysis and financial press releases;

(b) review with management and the external auditors, and recommend to the Board for approval, the interim financial statements of the Corporation and related financial reporting, including Management's Discussion and Analysis and financial press releases;

(c) review with management and recommend to the Board for approval, any financial statements of the Corporation which have not previously been approved by the Board and which are to be included in a prospectus of the Corporation;

(d) review with management and the external auditors, and recommend to the Board for approval, any audited financial statements of the Corporation's subsidiaries and reports of the external auditors thereon;

(e) consider and be satisfied that adequate procedures are in place for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements (other than disclosure referred to in clauses (a) and (b) above), and periodically assess the adequacy of such procedures;

(f) review with management, the external auditors and, if necessary, legal counsel, any litigation, claim or contingency, including tax assessments, that could have a material effect upon the financial position of the Corporation, and the manner in which these matters may be, or have been, disclosed in the financial statements;

(g) review the appropriateness of the accounting practices and policies of the Corporation, the use and effect of judgment on accounting measurements, the adequacy of accruals and estimates used by management in preparing financial statements and review any proposed changes in accounting policies and procedures;

(h) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate; and

(i) include in the annual information form each year, as required, a copy of the Terms of Reference of the Committee and a report to shareholders on the Committee's activities in satisfying its responsibilities during the year in compliance with these terms of reference.

2. Relationship with External Auditors.

The Committee shall:

(a) consider and make a recommendation to the Board as to the appointment or re appointment of the external auditors, ensuring that such auditors are participants in good standing pursuant to applicable securities laws;

(b) consider and make a recommendation to the Board as to the compensation of the external auditors;

(c) review and approve the annual audit plan of the external auditors in respect of the Corporation and any subsidiaries for which audited financial statements are required;

(d) oversee the work of the external auditors in performing their audit or review services and oversee the resolution of any disagreements between management and the external auditors;

(e) review and discuss with the external auditors all significant relationships that the external auditors and their affiliates have with the Corporation and its affiliates in order to determine the external auditors' independence, including, without limitation, (A) requesting, receiving and reviewing, on a periodic basis, a formal written statement from the external auditors delineating all relationships that may reasonably be thought to bear on the independence of the external auditors with respect to the Corporation, (B) discussing with the external auditors any disclosed relationships or services that the external auditors believe may affect the objectivity and independence of the external auditors, and (C) recommending that the Board take appropriate action in response to the external auditors' report to satisfy itself of the external auditors' independence;

(f) pre approve all non audit services (where such non audit services are considered to be above the *de minimus* level referred to in applicable law) to be provided to the Corporation (and any subsidiaries thereof) by the external auditors and review fee arrangements for such services (the

Committee may delegate to one or more of its members the authority to pre approve non audit services so long as such pre approval is presented to the full Committee at its first scheduled meeting following such pre approval); and

(g) review and approve the hiring policies of the Corporation regarding employees and former employees of the present and former external auditors of the Corporation.

3. Internal Controls.

The Committee shall:

(a) review with management and the external auditors, the adequacy and effectiveness of the internal control and management information systems and procedures of the Corporation (with particular attention given to accounting, financial statements and financial reporting matters) and determine whether the Corporation are in compliance with applicable legal and regulatory requirements and with the Corporation's policies;

(b) review the external auditors' recommendations regarding any matters, including internal control and management information systems and procedures, and management's responses thereto;

(c) establish procedures for the receipt, retention and treatment of complaints, submissions and concerns regarding accounting, internal controls or auditing matters on an anonymous and confidential basis; and

(d) review with external auditors any corporate transactions in which Directors or officers of the Corporation have a personal interest.

4. Financial Risk Management.

The Committee shall:

(a) review with management and the external auditors their assessment of significant financial risks and exposures;

(b) review and assess the steps that management has taken to mitigate such risks;

(c) review annually the insurable risks and insurance coverages of the Corporation; and

(d) report the results of such reviews to the Board for the purpose of assisting the Board in identifying the principal business risks associated with the businesses of the Corporation.