



**ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2006**

March 23, 2007

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FORWARD LOOKING STATEMENTS

Certain statements in this Annual Information Form are "forward looking statements". Forward looking statements are frequently characterized by words such as "plan", "expect", "project", "intend", "believe", "anticipate", "estimate", or other similar words, or statements that certain events or conditions "may" or "will" occur. Forward looking statements are not based on historical facts but rather on Management's expectations regarding the Corporation's 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 statements reflect Management's current beliefs and assumptions and are based on information currently available to Management. Forward looking statements involve 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 statements including risks associated with the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and 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 other public disclosure documents, and other factors, many of which are beyond the control of the Corporation. Although the forward looking statements contained in this Annual Information Form are based upon assumptions which Management believes to be reasonable, the Corporation cannot assure investors that actual results will be consistent with these forward looking statements. Assumptions relating to the reserves and resources of the Corporation are discussed under "Oil and Gas Reserves and Resources". These forward looking statements are 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. Because of the risks, uncertainties and assumptions inherent in forward looking statements, prospective investors in the Corporation's securities should not place undue reliance on these forward looking statements. See "Risk Factors".

ABBREVIATIONS AND DEFINITIONS

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

"bbl"	barrels	"mcf/d"	1,000 standard cubic feet per day
"bbl/d"	barrel or barrels per day	"mmcf"	1,000,000 cubic feet
"boe"	Barrels of oil equivalent	"mmcf/d"	1,000,000 cubic feet per day
"boe/d"	Barrel or barrels of oil equivalent per day	"mmbtu"	1,000,000 British thermal units
"mboe"	1,000 barrels of oil equivalent	"NGL"	Natural gas liquids
"mbbl"	1,000 barrels		
"mcf"	1,000 cubic feet		

Note: For the purposes of this document, 6 mcf of natural gas and 1 boe 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;

"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;

"**Connacher GLJ Report**" means the independent engineering evaluation of the oil and natural gas interests of the Corporation prepared by GLJ Petroleum Consultants Ltd. ("**GLJ**"), independent petroleum engineering consultants of Calgary, Alberta, dated March 9, 2007 and effective December 31, 2006;

"**Holly**" means Holly Corporation;

"**Luke**" means Luke Energy Ltd.;

"**Luke Acquisition**" means the acquisition by Connacher of all the outstanding common shares of Luke by way of a business combination under a plan of arrangement;

"**Luke Shares**" means the common shares in the share capital of Luke;

"**MRC**" means Montana Refining Company, Inc. (a wholly-owned subsidiary of the Corporation);

"**MRC Acquisition**" means the acquisition by Connacher of an 8,300 bbl/d refinery and related inventory situated in Great Falls, Montana operated by Holly's Montana Refinery Company;

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

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

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

"**Petrolifera AIF**" means the annual information form of Petrolifera for the year ended December 31, 2006 dated March 20, 2007;

"**Petrolifera GLJ Report**" means the independent engineering evaluation of the crude oil and natural gas interests of Petrolifera prepared by GLJ, independent petroleum engineering consultants of Calgary, Alberta, dated March 1, 2007 and effective December 31, 2006;

"**Puesto Morales Concession**" or "**Concession**" means the interests in the Puesto Morales and Rinconada blocks in the Neuquén Basin in Argentina;

"**Pod One**" means the Corporation's 10,000 bbl/d of bitumen SAGD project located in northeastern Alberta;

"**Refinery**" means the refinery and related inventory located in Great Falls, Montana acquired by the Corporation pursuant to the MRC Acquisition;

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

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

"**Sayer Energy Advisors Report**" means the independent evaluation of the Canadian undeveloped land acreage of the Corporation prepared by Sayer Energy Advisors ("**Sayer**"), independent oil and gas investment firm of Calgary, Alberta, dated February 14, 2007 and effective December 31, 2006;

"**Total Recoverable Resources**" means reserves plus Contingent Resources and Prospective Resources; 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

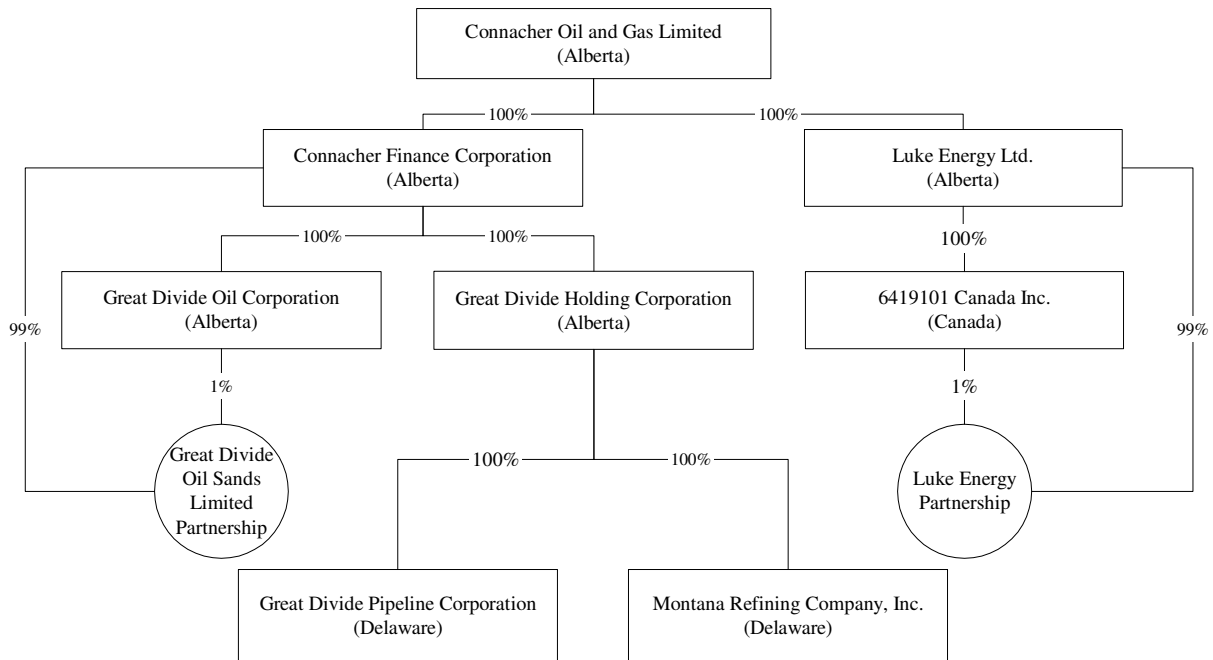
Incorporation and Organization

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, 2006, the Corporation had seven wholly-owned subsidiaries, 6419101 Canada Inc., a corporation incorporated under the *Canada Business Corporations Act*, Great Divide Oil Corporation, Connacher Finance Corporation, Luke Energy Ltd. and Great Divide Holding Corporation, all 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".

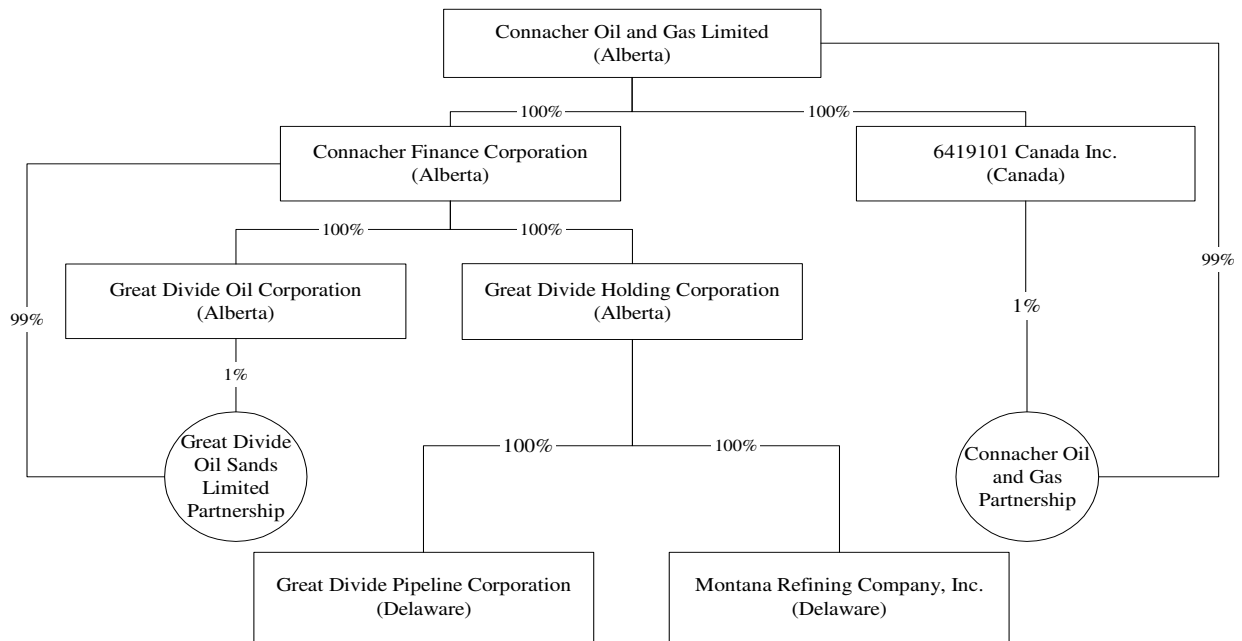
The Corporation has its head and principal office at Suite 2600, 530 – 8th Avenue S.W., Calgary, Alberta, T2P 3S8 and its registered office at 3700, 400 Third Avenue S.W., Calgary, Alberta, T2P 4H2.

The following chart illustrates the Corporation's organizational structure as at December 31, 2006:



On January 1, 2007 Connacher amalgamated with Luke Energy Ltd. pursuant to the ABCA and the name of the Luke Energy Partnership was changed to the Connacher Oil and Gas Partnership.

The following chart illustrates the Corporation's organizational structure as of the date of this Annual Information Form:



General Development of the Corporation

Connacher is primarily engaged in the exploration for, and the development, production and marketing of, crude oil and natural gas. The Corporation's principal asset is its interest in the Great Divide Pod One 10,000 bbl/d oil sands project and surrounding 90,000 acres of oil sands leases which are situated in northeastern Alberta. The Corporation also owns producing crude oil and natural gas properties at Battrum, Saskatchewan and at Marten Creek, Simonette and Three Hills, Alberta, a 9,400 bbl/d refinery located in Great Falls, Montana and a 26 percent equity interest in Petrolifera, a public Canadian oil and natural gas 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 July 2004, the Corporation sold its conventional heavy oil properties at Islay and Lloydminster in eastern Alberta, and its Cabri North natural gas properties and related undeveloped shallow gas rights under approximately 35,000 net acres in southwest Saskatchewan in two separate transactions for aggregate gross proceeds of \$17.8 million. Proceeds from these sales were used to repay bank debt and trade payables.

In November 2004, the Corporation acquired the 50% working interest it did not already own in the Puesto Morales Concession in Argentina and immediately thereafter sold its 100% working interest to its then subsidiary, Petrolifera, for eight million common shares of Petrolifera and a \$4 million promissory note. Prior to Petrolifera's purchase of those assets, Petrolifera completed a \$1.5 million equity financing issuing units comprised of one common share of Petrolifera and one common share purchase warrant of Petrolifera and used \$1.25 million of the net proceeds to reduce its promissory note indebtedness to the Corporation to \$2.75 million. As a consequence of Petrolifera's equity financing, the Corporation's equity interest in Petrolifera was reduced to 61%. This equity interest further reduced to 40% in March 2005, upon the completion of another equity financing by Petrolifera, which raised \$7 million by issuing units comprised of one common share of Petrolifera, one half of one common share purchase warrant of Petrolifera and a right. Of the gross proceeds, \$2 million was used to reduce the promissory note indebtedness owing to Connacher to \$750,000.

In December 2004, Connacher completed an equity offering of 30,000,000 Common Shares and 11,706,663 flow-through Common Shares, for aggregate gross proceeds of \$21.3 million. Proceeds from the financing were used to repay all of the Corporation's indebtedness and provide working capital.

Throughout 2004, a total of 1,442,155 Common Share purchase warrants and broker warrants and 575,000 stock options were exercised, resulting in the Corporation receiving cash proceeds of \$945,000.

Commencing in the third quarter of 2005, based upon Connacher's then equity interest in Petrolifera and as a result of the election of independent directors to the board of directors of Petrolifera and certain other factors, Connacher was no longer considered to control Petrolifera and, accordingly, Connacher discontinued consolidating Petrolifera's accounts with Connacher's financial results and began accounting for its investment in Petrolifera on an equity basis.

In September 2005, Connacher completed a public financing on a "bought-deal" basis of 27,027,400 Connacher Shares at a price of \$1.85 per share. An additional 13,513,600 Connacher Shares were issued to the underwriters in connection with such financing upon exercise of their over-allotment option for total gross proceeds of \$75,000,850. Proceeds from the financing were used to fund development of Connacher's Great Divide oil sands project and for general corporate purposes.

Petrolifera completed an initial public offering of its common shares and warrants in November 2005. Following completion of the initial public offering (and after giving effect to Connacher's investment of \$6 million in securities offered pursuant to the initial public offering), Connacher held an undiluted 35% equity interest (26% equity interest on a fully-diluted basis) in Petrolifera, reduced from a 40% equity interest Connacher held in Petrolifera prior to completion of the initial public offering and a 61% equity interest as at December 31, 2004.

In December 2005, Connacher completed the sale to a syndicate of underwriters of 5,000,000 flow-through Common Shares at a price of \$3.00 per share. Net proceeds from this financing were used by Connacher to incur eligible Canadian exploration expenses and, in that regard, primarily to further delineate and define Connacher's Great Divide oil sands properties through the drilling of additional core holes and shooting additional 3-D seismic.

In December 2005, Connacher and Luke entered into a binding letter agreement pursuant to which Connacher agreed to acquire the outstanding common shares of Luke by way of a business combination under a proposed plan of arrangement.

Also, in December 2005, Connacher entered into an exclusivity agreement with the Montana Refining Company, a subsidiary of Holly, to negotiate the terms of a purchase and sale agreement to acquire an 8,300 bbl/d refinery, together with related structures and specified tangible assets situated in Great Falls, Montana.

Throughout 2005, a total of 3,791,705 Common Share purchase warrants and broker warrants and 981,000 stock options were exercised, resulting in the Corporation receiving cash proceeds of \$2,652,296.

In February 2006, Connacher, Luke and 6492894 Canada Inc. entered into an arrangement agreement that set out the terms pursuant to which Connacher was to complete the Luke Acquisition. The Luke Acquisition was completed in March 2006 resulting in the payment of approximately \$91.5 million and the issuance from treasury of approximately 30 million Connacher Shares to Luke shareholders.

In February 2006, Connacher completed a "bought-deal" private placement financing of 8,571,500 Common Shares at a price of \$5.25 per share. An additional 10,476,300 Common Shares were issued to the underwriters in connection with the financing upon exercise of their over-allotment option for total gross proceeds of \$100,000,950. Proceeds from the financing were used to fund Connacher's exploration and development activities, for general corporate purposes and for working capital.

In March 2006, MRC signed an asset purchase agreement pursuant to which it completed the MRC Acquisition. The MRC Acquisition was completed on March 31, 2006. The consideration for the purchase was US\$55 million, comprised of cash and one million Connacher Shares from treasury. For further details with respect to the MRC Acquisition, reference should be made to the business acquisition report of the Corporation dated June 14, 2006 which is posted on SEDAR (www.sedar.com) and is not incorporated by reference in this Annual Information Form.

In June 2006, Connacher received a letter from the Alberta Energy and Utilities Board approving the Corporation's Great Divide oil sands project.

In July 2006, Connacher was granted an Order in Council approving its Great Divide oil sands project, representing the last formal approval requirement for the project to proceed.

In September 2006, Connacher completed a "bought-deal" financing of 5,000,000 flow-through common shares at a price of \$5.25 per flow-through share. An additional 714,300 flow-through shares were issued to the underwriters in connection with the financing upon exercise of their over-allotment option for total gross proceeds of \$30,000,075. Proceeds from the financing were used to fund exploration activities including the further delineation of the Corporation's oil sands properties.

In October 2006, Connacher completed a long term debt financing comprised of a US\$180 million Term Loan B Facility (the "TLB Facility") and US\$15 million Working Capital Facility (the "WC Facility") (collectively, the "Facilities"). The Facilities were syndicated to institutional investors located primarily in the United States and in Canada. The proceeds of the TLB Facility were used to discharge short-term indebtedness of US\$51 million incurred in the MRC Acquisition, fund a one year debt service reserve during the construction phase of Pod One and pay expenses associated with the long-term debt financing. The balance of the approximately US\$111 million of the proceeds was added to cash working capital and will be used to finance the remaining construction and related capital expenditures of Pod One. The WC Facility is available to fund ongoing working capital requirements at the Refinery.

Throughout 2006, a total of 1,493,820 Common Share purchase warrants and 998,365 stock options were exercised, resulting in the Corporation receiving cash proceeds of \$1,898,000.

Trends

There are some trends that have been developing in the oil and gas industry during the past two years.

The first trend is the consolidation that the industry has been experiencing. Consolidation has affected companies of all sizes from the small emerging companies to the senior integrated companies. Because of the relatively high commodity prices in the industry in recent history and the increased demand for producing properties, the trend in the industry is for larger entities to continue to acquire smaller entities. To date, oil and gas royalty trusts have also been a significant acquirer of producing oil and gas properties and companies. However, proposed legislation to change the taxation of trusts announced on October 31, 2006 has affected this trend.

The second trend is the significant access to external capital that the industry has been experiencing. Oil and gas companies have had access to debt and equity capital which they have invested in both acquisition and exploration activities. More recently, however, the access to external capital has become more restricted as a result of declining commodity prices and legislative changes in taxation applicable to trusts.

The third trend is the focus on Canada's oil sands deposits. In 2005 and 2006 the market for crude oil saw record high prices which persisted in the context of volatile geopolitical conditions. Strong demand growth and the forecast of continued growth from China, India and other developing nations also contributed to the quantum jump in crude oil prices. These strong prices brought into focus the relentless issue of reserve replacement and the continuing debate about the reliability of supply from established petroleum-producing regions. These rising oil prices and the need for dependable long-term supplies coalesced during 2005 and 2006 and brought Canada's oil sands deposits into focus. The unofficial oil sands "press index" reached an all-time high, with financial papers reporting almost relentlessly on the projects under development and the potential importance to North American certainty of supply of the oil sands. As a result of the foregoing there was a significant increase in the prices being paid for oil sands properties in 2005 and 2006.

A fourth trend is the high level at which the industry is operating and the resulting intense competition for services and personnel to meet corporate capital expenditure programs. This has resulted in increased operating, exploration and development costs. See "Risk Factors".

BUSINESS OF THE CORPORATION

Connacher is primarily engaged in the exploration for, and the development, production and marketing of, crude oil and natural gas. The Corporation's principal asset is its interest in the Great Divide Pod One 10,000 bbl/d oil sands project and surrounding 90,000 acres of oil sands leases which are situated in northeastern Alberta. The Corporation also owns producing crude oil and natural gas properties at Batrum, Saskatchewan and at Marten Creek, Simonette and Three Hills, Alberta, a 9,400 bbl/d refinery located in Great Falls, Montana and a 26 percent

equity interest in Petrolifera, a public Canadian oil and natural gas 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.

Great Divide, Alberta

At Great Divide in northeastern Alberta, the Corporation owns and operates 148.5 sections of oil sands leases (148.2 sections or 95,000 acres net) and 11 gross sections (10 net sections or 6,400 acres) of petroleum and natural gas rights. Several bitumen accumulations or pods have been identified.

Pod One was delineated, evaluated, applied for and approved by all applicable regulatory bodies. It is currently under construction, and is scheduled for startup in mid-summer 2007. Additional pods are being delineated using core-hole drilling and 3D seismic in the first quarter 2007. At this time 81 coreholes are planned. This data will be integrated into the existing corehole and seismic data base to determine whether there is sufficient size, areal extent and reservoir quality to apply for additional new pods or SAGD developments. In addition, the Corporation is using this data to explore for and find additional new pods. The Corporation intends to proceed with an application to develop another 10,000 bbl/d small scale commercial operation (the "Algar Project") at Great Divide. It is anticipated the application for the Algar Project will be submitted in May, 2007 with a view to commencement of construction in early 2008, subject to final approval by the Board of Directors of the Corporation and following due consultation with stakeholders and receipt of regulatory approval.

As at December 31, 2006 the Connacher GLJ Report estimated the Corporation's Pod One proved reserves to be 43.8 million barrels, 2P reserves to be 84.1 million barrels and the 3P reserves to be 109.9 million barrels. Additional pods were assigned Contingent and Prospective Resources (as such terms are hereinafter defined) resulting in a 2P reserves and Best Estimate of Total Recoverable Resources of 260.6 million barrels. The 3P reserves and High Estimate of Total Recoverable Resources was estimated at 478.9 million barrels.

Marten Creek, Alberta

Marten Creek is a relatively shallow (1,925 feet) multi-zone Cretaceous natural gas area located about 300 miles north of Calgary and it is predominately 100% owned and operated by Connacher. Gas production for 2006 averaged 11.3 mmcf/d. Connacher's land position has grown to an average 80% interest in approximately 77,600 acres (62,124 acres net). Connacher also holds an additional 4,480 acres under option. Connacher has accumulated a seismic base in excess of 1,100 miles of 2D seismic data on which over 25 potential drilling locations have been identified on existing lands. This is a winter work area and all work must be completed by the end of March, which is generally the start of spring break-up. At December 31, 2006, the Corporation estimates total 2P recoverable reserves as 5.0 million boes.

Three Hills, Alberta

In March 2006, Connacher acquired the Three Hills properties (Three Hills, Mikwan, Twining and Stettler) through the Luke Acquisition. At the time of the Luke Acquisition the Three Hills properties were producing approximately 225 boe/d. By drilling additional wells in 2006 these properties exited the year producing more than 375 boe/d. At December 31, 2006 the Connacher GLJ Report estimates the Corporation's working interest share of crude oil reserves rose to 728 mboe (proved) from 456 mboe (proved) at the time the Luke Acquisition was completed in March of 2006. The 2P recoverable reserves have risen from 582 mboe to 1,205 mboe during the same period.

Battrum, Saskatchewan

The Corporation owns and operates working interests of 100% in unitized and non unitized lands in the Battrum region of southwestern Saskatchewan. The properties produce medium gravity crude oil. The bulk of the

properties were acquired in two transactions in 2003, with additional small transactions completed in 2005 and 2006. For the year ended December 31, 2006 the Corporation's production from this area averaged 710 bbls/d of oil and current production is approximately 650 bbl/d of oil. There are presently 56 net producing oil wells and no producing gas wells in this area, which comprises 26,922 gross acres and 26,842 net acres. At December 31, 2006 the Connacher GLJ Report estimates the Corporation's working interest share of crude oil reserves to be 2.4 million bbls of oil, of which 1.9 million bbls is proved.

The Refinery

On March 31, 2006, the Corporation completed the MRC Acquisition. See "The Corporation - General Development of the Corporation".

The MRC Acquisition was considered strategic to provide Connacher with protection against wider and more volatile type of heavy crude oil price differential swings. Since its acquisition, the Refinery has been a profitable and strong business unit contributing to the Corporation's cash flow. MRC's continued profitability will depend largely on the spread between market prices for refined petroleum products and the cost of crude oil.

MRC's principal source of revenue is from the sale of high value light end products such as gasoline, diesel, and jet fuel in markets in the western United States. Additionally, MRC sells a high grade asphalt into the local market. MRC's principal expenses relate to costs of products sold and operating expenses.

In April 2006, MRC completed a scheduled plant "turnaround" maintenance program of its refinery facilities. Such turnarounds are normally scheduled every two to five years. Turnaround costs are capitalized and amortized over the period to the next scheduled turnaround.

With minimal additional anticipated capital investment, MRC would be capable of producing low sulfur gasoline and diesel as required in 2008.

The above mentioned regulatory compliance items or other presently existing or future environmental regulations, could cause Management to make additional capital investments beyond those described above and/or incur additional operating costs to meet applicable requirements.

In 2004, the American Jobs Creation Act of 2004 was signed into law. Among other things, the legislation creates tax incentives for small refiners preparing to produce low sulfur gasoline and diesel. The legislation provides an immediate deduction of 75% of certain costs paid or incurred to comply with these standards and a tax credit based on production for up to 25% of those costs. Management intends to utilize these incentives when it is required to make these required expenditures.

Ownership of Petrolifera

As of the date of this Annual Information Form Connacher owns an undiluted 26% equity interest in Petrolifera. Petrolifera commenced a drilling program in late 2005 and has since completed 14 wells in its 100% owned Puesto Morales Concession located in the Neuquén Basin in Argentina, all of which have been completed as hydrocarbon discoveries.

Petrolifera is a publicly traded crude oil and natural gas exploration and production company active in Argentina, Colombia and Peru with its common shares listed for trading on the TSX under the symbol "PDP". Connacher discontinued consolidating Petrolifera's accounts with Connacher's financial results commencing in the third quarter of 2005 and now accounts for its investment in Petrolifera on an equity basis. See "The Corporation - General Development of the Corporation". As of the date hereof, Connacher owns 11.4 million common shares of Petrolifera, warrants to purchase 1.7 million common shares of Petrolifera which expire May 8, 2006 and options to purchase 200,000 common shares of Petrolifera. Based on the closing trading price of Petrolifera on March 23, 2007 of \$19.07, Connacher's ownership of common shares of Petrolifera (excluding common shares issuable upon the exercise of options and warrants) represents a \$217 million investment. Petrolifera has forecasted capital expenditures of \$153 million to complete an active drilling and facility installation program during 2007.

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 2006 separately from its own corresponding reserves data and other oil and gas information. Set out in Schedule C to this Annual Information Form is a summary of the Corporation's 26% interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2006 as evaluated by GLJ in the Petrolifera GLJ Report. 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 and constant price evaluations is set forth in the notes to the tables. All of the reserves assigned to Petrolifera in the Petrolifera GLJ Report are located in the Puesto Morales Concession in Argentina. Readers are cautioned that as a result of the exercise of any outstanding options and warrants 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 AND GAS RESERVES AND RESOURCES

Connacher engaged GLJ to prepare a report relating to the Corporation's reserves and resources as at December 31, 2006. The information set forth below relating to the Corporation's reserves and resources constitutes forward looking statements which are subject to certain risks and uncertainties. See "Forward Looking Statements" and "Risk Factors".

Oil and Gas Reserves

Connacher's crude oil and natural gas reserves are primarily located in three areas, the Battrum area of Saskatchewan and the Marten Creek and Three Hills areas of Alberta. Connacher's bitumen reserves are located in the Great Divide region. Bitumen reserves were only assigned to Pod One, in the 2P and 3P categories. The Connacher GLJ Report assumed 44 SAGD well pairs for the proved undeveloped case, 62 SAGD well pairs for the 2P case and 76 well pairs for the 3P case, with cumulative SORs of 2.7, 2.6 and 2.6 in each case, but declining to 2.4 during peak production periods. The cutoffs used by GLJ for probable reserves were 15 metres of net pay for proved undeveloped reserves, 13 metres of net pay for 2P reserves and 10 metres of net pay for 3P reserves.

Set out below is a summary of the crude oil, natural gas and bitumen reserves and the value of future net revenue of the Corporation as at December 31, 2006 as evaluated by GLJ in the Connacher GLJ Report. The preparation date of the Connacher GLJ Report is March 7, 2007. The pricing used in the forecast and constant price evaluations is set forth in the notes to the tables. Detailed information with respect to the reserves and future net revenue attributable to the Corporation's crude oil and natural gas reserves and the Corporation's bitumen reserves is included in this Annual Information Form under the headings "Oil and Gas Reserves and Resources - Supplemental Information Regarding the Corporation's Bitumen Reserves" and "Oil and Gas Reserves and Resources - Supplemental Information Regarding the Corporation's Crude Oil and Natural Gas Reserves", respectively.

Under NI 51-101, proved reserve assignments are based on a 90% probability that total quantities recovered will equal or exceed proved reserve estimates. Proved plus probable reserves are the most likely case and are based on a 50% probability that they will equal or exceed estimates. Proved plus probable plus possible reserves are the least likely case and are based on a 10% probability that they will equal or exceed estimates.

The evaluations of the Corporation's bitumen reserves based on constant prices and costs utilize a net bitumen price derived from pricing data posted as of December 31, 2006. Although December 31, 2006 prices are utilized, production of bitumen is not anticipated to commence until mid-2007. Accordingly, if product prices from which the net bitumen price is derived decline, then the present value of future net revenue associated with reserves and the associated reserves volumes will be less than those estimated in the Connacher GLJ Report and such reductions may be significant. 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 and constant 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.

RESERVES DATA - FORECAST PRICES AND COSTS

CONVENTIONAL AND NON-CONVENTIONAL RESERVES BASED ON FORECAST PRICES AND COSTS⁽⁹⁾

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids		Bitumen	
	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾
	(mdbl)	(mdbl)	(mmcf)	(mmcf)	(mdbl)	(mdbl)	(mdbl)	(mdbl)
Proved Developed Producing ⁽²⁾⁽⁵⁾	2,106	1,742	21,524	17,607	1	1	-	-
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	-	-	3,167	2,615	-	-	-	-
Proved Undeveloped ⁽²⁾⁽⁷⁾	315	240	-	-	-	-	43,841	39,808
Total Proved ⁽²⁾	2,421	1,983	24,691	20,221	1	1	43,841	39,808
Total Probable ⁽³⁾	786	632	8,769	7,158	-	-	40,307	34,340
Total Proved Plus Probable ⁽²⁾⁽³⁾	3,207	2,615	33,460	27,379	2	1	84,147	74,178
Total Possible ⁽⁴⁾	-	-	-	-	-	-	25,714	21,596
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	3,207	2,615	33,460	27,379	2	1	109,861	95,774

NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS⁽⁹⁾

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved Developed Producing ⁽²⁾⁽⁵⁾	159,543	127,039	105,942	91,289	80,557	150,364	120,756	101,435	87,927	77,968
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	15,782	12,554	10,237	8,518	7,209	11,170	8,885	7,241	6,021	5,092
Proved Undeveloped ⁽²⁾⁽⁷⁾	528,477	319,949	196,214	118,765	67,960	410,037	245,832	147,487	85,325	44,145
Total Proved ⁽²⁾	703,801	459,543	312,394	218,572	155,727	571,572	375,472	256,163	179,274	127,205
Total Probable ⁽³⁾	850,214	389,295	216,420	144,432	110,810	603,624	277,682	158,003	109,383	87,218
Total Proved Plus Probable ⁽²⁾⁽³⁾	1,554,015	848,838	528,813	363,004	266,537	1,175,196	653,154	414,165	288,657	214,423
Total Possible ⁽⁴⁾	613,264	200,769	87,661	51,283	37,084	435,225	142,512	63,256	38,119	28,439
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	2,167,279	1,049,607	616,474	414,287	303,621	1,610,421	795,666	477,421	326,776	242,862

FUTURE NET REVENUE (UNDISCOUNTED) BASED ON FORECAST PRICES AND COSTS⁽⁹⁾

	Revenue ⁽¹⁰⁾	Royalties ⁽¹¹⁾	Operating Expenses	Capital Costs	Abandonment Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved ⁽²⁾	1,954,696	215,170	754,150	271,753	9,822	703,801	132,230	571,572
Total Proved Plus Probable ⁽²⁾⁽³⁾	3,923,893	505,718	1,433,916	416,529	13,715	1,554,015	378,819	1,175,196
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	5,266,838	713,155	1,871,568	498,308	16,528	2,167,279	556,858	1,610,421

**FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M\$)
Total Proved ⁽²⁾	Light and medium crude oil (including solution gas and by-products)	40,124
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	81,548
	Bitumen	190,721
Total Proved Plus Probable ⁽²⁾⁽³⁾	Light and medium crude oil (including solution gas and by-products)	51,565
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	100,851
	Bitumen	376,398
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	Light and medium crude oil (including solution gas and by-products)	51,565
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	100,851
	Bitumen	464,059

RESERVES DATA - CONSTANT PRICES AND COSTS

**CONVENTIONAL AND NON-CONVENTIONAL RESERVES
BASED ON CONSTANT PRICES AND COSTS⁽⁸⁾**

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids		Bitumen	
	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾	Gross ⁽¹⁾	Net ⁽¹⁾
	(mdbl)	(mdbl)	(mmcf)	(mmcf)	(mdbl)	(mdbl)	(mdbl)	(mdbl)
Proved Developed Producing ⁽²⁾⁽⁵⁾	2,125	1,759	21,531	17,611	1	1	-	-
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	-	-	3,167	2,615	-	-	-	-
Proved Undeveloped ⁽²⁾⁽⁷⁾	315	240	-	-	-	-	43,841	39,607
Total Proved ⁽²⁾	2,440	1,999	24,698	20,226	1	1	43,841	39,607
Total Probable ⁽³⁾	794	640	8,769	7,157	-	-	40,307	33,958
Total Proved Plus Probable ⁽²⁾⁽³⁾	3,234	2,639	33,467	27,383	2	1	84,147	73,565
Total Possible ⁽⁴⁾	-	-	-	-	-	-	25,714	21,425
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	3,234	2,639	33,467	27,383	2	1	109,861	94,990

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

	Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Proved Developed Producing ⁽²⁾⁽⁵⁾	127,893	103,715	87,603	76,174	67,665	127,532	103,517	87,491	76,109	67,627
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	10,939	8,770	7,194	6,012	5,104	7,768	6,559	5,610	4,852	4,236
Proved Undeveloped ⁽²⁾⁽⁷⁾	457,526	279,244	171,784	103,521	58,135	359,803	217,408	130,752	75,155	37,827
Total Proved ⁽²⁾	596,357	391,730	266,581	185,707	130,905	495,103	327,484	223,853	156,116	109,690
Total Probable ⁽³⁾	621,112	300,873	178,397	126,108	100,884	441,790	215,884	131,663	96,751	80,367
Total Proved Plus Probable ⁽²⁾⁽³⁾	1,217,469	692,603	444,978	311,815	231,788	936,892	543,368	355,516	252,867	190,057
Total Possible ⁽⁴⁾	392,227	139,383	67,677	43,387	33,241	278,509	99,304	49,235	32,557	25,703

	Before Deducting Income Taxes					After Deducting Income Taxes				
	Discounted At					Discounted At				
	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	1,609,696	831,986	512,655	355,202	265,029	1,215,401	642,672	404,751	285,424	215,760

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

	Revenue ⁽¹⁰⁾ (M\$)	Royalties ⁽¹¹⁾ (M\$)	Operating Expenses (M\$)	Capital Costs (M\$)	Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Total Proved ⁽²⁾	1,631,014	181,930	587,495	257,509	7,721	596,359	101,256	495,103
Total Proved Plus Probable ⁽²⁾⁽³⁾	2,974,322	396,859	999,768	350,562	9,651	1,217,482	280,590	936,892
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	3,769,898	529,524	1,225,888	393,727	11,051	1,609,708	394,307	1,215,401

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

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (M\$)
Total Proved ⁽²⁾	Light and medium crude oil (including solution gas and by-products)	41,117
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	59,179
	Bitumen	166,285
Total Proved Plus Probable ⁽²⁾⁽³⁾	Light and medium crude oil (including solution gas and by-products)	52,640
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	72,018
	Bitumen	320,324
Total Proved Plus Probable Plus Possible ⁽²⁾⁽³⁾⁽⁴⁾	Light and medium crude oil (including solution gas and by-products)	52,640
	Associated gas and non-associated gas (including natural gas liquids and excluding solution gas)	72,018
	Bitumen	388,002

**RECONCILIATION OF COMPANY CONVENTIONAL AND NON-CONVENTIONAL RESERVES BY
PRINCIPAL PRODUCT TYPE BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

The following table sets forth a reconciliation of the changes in Connacher's working interest, after royalties, of light crude oil (including NGL's), associated and non-associated natural gas (combined) and bitumen reserves as at December 31, 2006 against such reserves as at December 31, 2005 based on the forecast price and cost assumptions set forth in Note 9.

	Light and Medium Oil			Associated and Non-Associated Natural Gas			Bitumen		
	Net Proved (1)(2)	Net Probable (1)(3)	Net Proved Plus Probable (1)(2)(3)	Net Proved (1)(2)	Net Probable (1)(3)	Net Proved Plus Probable (1)(2)(3)	Net Proved (1)(2)	Net Probable (1)(3)	Net Proved Plus Probable (1)(2)(3)
	(mdbl)	(mdbl)	(mdbl)	(mmcf)	(mmcf)	(mmcf)	(mdbl)	(mdbl)	(mdbl)
At December 31, 2005	1,161	744	1,905	236	282	518	-	62,667	62,667
Extensions	174	185	358	526	385	912	-	11,481	11,481
Improved Recovery	213	17	230	-	-	-	39,808	(39,808)	-
Technical Revisions	305	(306)	(1)	467	(95)	372	-	-	-
Discoveries	-	-	-	-	-	-	-	-	-
Acquisitions	406	138	544	22,412	6,773	29,184	-	-	-
Dispositions	(8)	(145)	(153)	(83)	(187)	(270)	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
Production	(268)	-	(268)	(3,336)	-	(3,336)	-	-	-
At December 31, 2006	1,983	632	2,615	20,222	7,158	27,379	39,808	34,340	74,148

**RECONCILIATION OF CHANGES IN NET PRESENT VALUES
OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT 10%
BASED ON CONSTANT PRICES AND COSTS⁽⁸⁾**

The following table sets forth changes between future net revenue estimates attributable to Connacher's net proved reserves as at December 31, 2006 against such reserves as at December 31, 2005 based on constant prices and cost assumptions set forth in Note 8 and calculated using a discount rate of 10%.

	<u>(M\$)</u>
Estimated Future Net Revenue after income taxes at December 31, 2005	34,060
Sales and Transfers of Oil and Gas Produced, Net of Production Costs and Royalties	(23,516)
Net Change in Prices, Production Costs and Royalties Related to Future Production	(1,776)
Changes in Previously Estimated Future Development Costs	167,917
Changes in Estimated Future Development Costs	(167,604)
Net Change from Extensions and Improved Recovery	175,359
Net Change from Discoveries	-
Acquisitions of Reserves	77,477
Dispositions of Reserves	-
Net Change Resulting from Revisions in Quantity Estimates	4,777
Accretion of Discount	3,553
Net Change in Income Taxes	(41,259)
Other	(5,134)
Estimated Future Net Revenue after income taxes at December 31, 2006	223,853

Notes:

- "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.
- "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is 90% 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. There is only a 10% probability that the quantities actually recovered will equal or exceed the sum of 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 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.
- (8) The product prices used in the constant price and cost evaluations in the Connacher GLJ Report were as follows: (1) Edmonton Light price: \$67.58/bbl; (2) AECO Spot Gas price: \$6.07/mmbtu; and (3) Alberta Sulphur at Plant Gate: \$19.50/L.
- (9) 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 Crude Oil	Heavy Oil	Inflation	Exchange Rate
	Edmonton Par Price 40^o API (\$Cdn/bbl)	Hardisty Heavy 12^o API (\$Cdn/bbl)	%/year	\$US/\$Cdn
Forecast				
2007	70.25	39.25	2.0	0.870
2008	68.00	40.00	2.0	0.870
2009	65.75	39.75	2.0	0.870
2010	64.50	39.75	2.0	0.870
2011	64.50	40.25	2.0	0.870
2012	65.00	41.50	2.0	0.870
2013	66.25	42.50	2.0	0.870
2014	67.75	43.50	2.0	0.870
2015	69.00	44.25	2.0	0.870
Thereafter	+2.0%/yr	+2.0%/yr	2.0	0.870

- (10) Values include processing and other income.
- (11) Values include Alberta Royalty Tax Credit.

Weighted average historical prices realized by the Corporation for the year ended December 31, 2006 were \$53.85/bbl for light and medium crude and \$5.85/mcf for natural gas. Although gas prices are expected to move upward in the near term, there is no specific "price path" for the Corporation's gas because of its relatively small sales volumes and due to the possible influence other larger gas sales contracts negotiated with industrial buyers may have on the Corporation's realized prices. Although "price paths" represent generic expected trends, actual pricing may be specific to different producing areas. If additional volumes are developed in a particular area, more pricing power could accrue to the producer.

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, 2006, Connacher's conventional net proved undeveloped reserves of 445 mbbbls of oil are located at Battrum, Saskatchewan and Three Hills, Alberta. The Corporation expects to drill a number of infill locations at Battrum and Three Hills during 2007 which, if successful, would result in new reserves qualifying for the proved developed category.

Probable undeveloped reserves relate to wells to be drilled, tied in and brought on-stream in future. The Connacher GLJ Report estimates the Corporation's working interest probable undeveloped reserves to be 786 mbbbls of light or medium oil and estimates the Corporation's working interest probable undeveloped reserves to be 40,307 mbbbls of bitumen.

At Great Divide, proved undeveloped reserves of 43.8 million bbls of bitumen were assigned by GLJ in the Connacher GLJ Report. Proved undeveloped reserves will be converted to proved developed producing reserves over time once the Great Divide project is commissioned and as the steam injected in the SAGD well pairs heats up the reservoir enabling it to reach maximum production.

Significant Factors or Uncertainties

The Corporation does not anticipate that any important economic factors or significant uncertainties would affect particular components of the reserves data. Notwithstanding that, a number of factors which are beyond the Corporation's control can significantly affect the 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 Constant Dollar Costs (M\$)	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\$)
2007	121,969	121,969	110,562	97,527
2008	40,530	41,341	1,255	1,255
2009	3,200	3,329	3,121	2,913
2010	40	42	32	32
2011	1,800	1,948	22	22
Total for all remaining years	140	188	186,126	293,689
Total, undiscounted	257,509	271,753	416,529	498,308
Total for all years discounted at 10%/year	199,841	207,195	204,438	196,977

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.

Oil and Gas Properties and Wells

The following table sets forth the number of wells in which Connacher held a working interest as at December 31, 2006:

	Crude Oil		Natural Gas	
	Gross⁽¹⁾	Net⁽¹⁾	Gross⁽¹⁾	Net⁽¹⁾
Alberta				
Producing	12	11	42	40
Non-producing	8	8	4	4
Saskatchewan				
Producing	56	56	-	-
Non-producing	32	32	-	-
Total	108	107	46	44

Note:

- (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.

Costs Incurred

The following table summarizes the capital expenditures made by Connacher on oil and natural gas properties for the year ended December 31, 2006.

Property Acquisition Costs		Exploration Costs	Development Costs
(\$)		(\$)	(\$)
Proved Properties	Unproved Properties		
-	6,767,000	39,038,188	20,008,687

Exploration and Development Activities

The following table sets forth the number of exploratory and development wells which Connacher completed during its 2006 financial year:

	Exploratory Wells		Development Wells	
	Gross⁽¹⁾	Net⁽¹⁾	Gross⁽¹⁾	Net⁽¹⁾
Oil Wells ⁽²⁾	27	27	9	8.8
Gas Wells	-	-	3	1.5
Service Wells	-	-	-	-
Dry Holes	2	2	1	1
Total Completed Wells	29	29	13	11.3

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 26 oil sands exploration delineation coreholes.

In 2007 focus will continue to be on Great Divide although other important work will be carried out on the Corporation's conventional acreage and at the Refinery. A capital budget approaching \$250 million is envisaged for 2007, with approximately 80 percent directed to both Pod One development and startup and to anticipating continued evaluation of additional pods and undeveloped acreage in the Great Divide region. It is hoped a formal applications for the next pod at Great Divide will be submitted early in 2007. Conventional activity will focus on drilling for natural gas at Marten Creek and other selected regions in northern Alberta, oil development drilling at Three Hills, Alberta and ongoing projects at Battrum, Saskatchewan. It is also anticipated over \$16 million will be invested in the operation of the Refinery during 2007.

Properties with No Attributed Reserves

The following table sets out the Corporation's undeveloped land position effective December 31, 2006.

	Undeveloped Acreage	
	Gross⁽¹⁾	Net⁽¹⁾
Alberta		
Conventional	114,116	94,948
Oil Sands	81,920	81,728
Saskatchewan	62,340	51,011
British Columbia	3,249	2,858
Total	261,625	230,545

Note:

- (1) "Gross" means the total number of acres in which the Corporation has a working interest. "Net" means the sum of the products obtained by multiplying the number of gross acres by the Corporation's percentage working interest therein.

The Corporation does not expect its rights to explore, develop and exploit any of its unproved property 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, 2006. In the Sayer Report a fair value of approximately \$16.2 million or approximately \$206.85 per gross hectare was assigned to Connacher's non-reserve oil and gas properties. This equates to approximately \$83.06 per gross acre. 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.

This complies with the criteria set out in paragraph (a), subsection (2), Section 5.10 of NI 51-101.

Pursuant to the Corporation's discretionary capital program for 2007, Connacher anticipates directing the majority of its 2007 capital budget on the completion of its development project at Great Divide. Additional capital and related budgetary allocations will be required during 2007 once a final determination is made regarding transportation and development of the Corporation's next Pod.

Asset Retirement Obligations

The Corporation follows the Canadian Institute of Chartered Accountants' standard on Asset Retirement Obligations. 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, 2006, the estimated total undiscounted amount required to settle the asset retirement obligations in respect of the Corporation's 151 net producing and non-producing wells, net of estimated salvage recoveries, was \$17.4 million. These obligations will be settled over the useful lives of the underlying assets, which currently extend up to 20 years. The 10% discounted present value of this amount is \$4.8 million. Over the next three financial years, the Corporation expects to incur \$461,000 (\$389,000 discounted at 10%) of these expenditures.

In the Connacher GLJ Report, abandonment costs for total proved plus probable plus possible reserves were estimated to be \$13.7 million, undiscounted, and \$3.0 million, discounted at 10%. These estimates are in respect of well costs only and do not include costs to abandon pipelines and facilities, which the Corporation has included in determining its asset retirement obligation.

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 \$300 million. Based on anticipated capital spending, which augment the tax pools, the Corporation does not expect to pay current income taxes for the 2006 fiscal year. Depending on

production, commodity prices and capital spending levels, the Corporation may begin paying current income taxes in 2007.

Production Estimates

The following table sets forth the volume of working interest production, before royalties, estimated for 2007 which is reflected in the estimate of future net revenue disclosed in the tables of reserve information in respect of total gross proved plus probable reserves:

<u>Light Crude Oil (mdbl)</u>	<u>Natural Gas (mmcf)</u>	<u>Natural Gas Liquids (bbl)</u>	<u>Bitumen (mdbl)</u>
407	4,122	-	767

The following table indicates the volume of working interest production, before royalties, estimated for 2007 from fields considered to be individually important:

	<u>Light Crude Oil (mdbl)</u>	<u>Natural Gas (mmcf)</u>	<u>Natural Gas Liquids (mdbl)</u>	<u>Bitumen (mdbl)</u>
Battrum, Saskatchewan	301	-	-	-
Marten Creek, Alberta	-	3,618	-	-
Great Divide, Alberta	-	-	-	767

Production History

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

	<u>Three Months Ended March 31, 2006</u>	<u>Three Months Ended June 30, 2006</u>	<u>Three Months Ended September 30, 2006</u>	<u>Three Months Ended December 31, 2006</u>
Average Daily Production				
Light and Medium Oil (bbl/d)	689	1,026	1,084	1,139
Natural Gas (mcf/d)	2,600	15,172	13,028	11,291
Average Net Prices Received				
Light and Medium Oil (\$/bbl)	\$40.93	\$61.45	\$62.53	\$46.65
Natural Gas (\$/mcf)	\$6.34	\$5.66	\$5.33	\$6.57
Royalties				
Light and Medium Oil (\$/bbl)	\$8.25	\$15.31	\$15.63	\$9.97
Natural Gas (\$/mcf)	\$1.28	\$1.41	\$1.32	\$1.40
Production Costs				
Light and Medium Oil (\$/bbl)	\$8.46	\$11.20	\$11.86	\$10.26
Natural Gas (\$/mcf)	\$1.31	\$1.03	\$1.01	\$1.45
Netback Received				
Light and Medium Oil (\$/bbl)	\$24.22	\$34.94	\$35.13	\$26.42
Natural Gas (\$/mcf)	\$3.75	\$3.22	\$3.00	\$3.72

The following table indicates the Corporation's average daily production for the year ended December 31, 2006 from fields considered to be individually important:

	<u>Light Crude Oil (bbls/d)</u>	<u>Natural Gas (mcf/d)</u>	<u>Natural Gas Liquids (bbls/d)</u>
Battrum, Saskatchewan	723	-	-
Marten Creek, Alberta	-	9,869	-

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 and gas processing facilities;
- employing highly competent professional staff who use leading-edge technology; and
- striving to be a low-cost producer.

Supplemental Information Regarding the Corporation's Bitumen Reserves

The following is a summary of the bitumen reserves and the value of future net revenue of the Corporation as at December 31, 2006 as evaluated by GLJ in the Connacher GLJ Report. The Connacher 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 and constant price evaluations is included in the notes set forth on page 14 of this Annual Information Form.

BITUMEN RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON FORECAST PRICES AND COSTS⁽⁹⁾

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes Discounted At				
	Gross ⁽¹⁾ (mbbl)	Net ⁽¹⁾ (mbbl)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved ⁽²⁾	43,841	39,808	520,514	313,409	190,721	114,067	63,883	404,453	241,216	143,596	81,991	41,249
Total Probable ⁽³⁾	40,306	34,340	777,149	344,277	185,677	121,873	93,375	551,068	245,573	136,150	93,361	74,828
Proved Plus Probable Undeveloped ⁽²⁾⁽³⁾⁽⁷⁾	84,147	74,148	1,297,663	657,686	376,398	235,940	157,258	955,521	486,789	279,746	175,352	116,077
Total Possible ⁽⁴⁾	25,714	21,626	613,264	200,769	87,661	51,283	37,084	435,225	142,513	63,256	38,119	28,440
Proved Plus Probable Plus Possible Undeveloped ⁽²⁾⁽³⁾⁽⁴⁾⁽⁷⁾	109,861	95,774	1,910,927	858,455	464,059	287,223	194,342	1,390,746	629,302	343,002	213,471	144,517

BITUMEN RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE BASED ON CONSTANT PRICES AND COSTS⁽⁸⁾

	Bitumen		Before Deducting Income Taxes Discounted At					After Deducting Income Taxes ¹ Discounted At				
	Gross ⁽¹⁾ (mbbl)	Net ⁽¹⁾ (mbbl)	0%	5%	10%	15%	20%	0%	5%	10%	15%	20%
	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)	(M\$)
Total Proved ⁽²⁾	43,841	39,607	449,563	272,700	166,285	98,815	54,049	354,251	212,757	126,770	71,688	34,767
Total Probable ⁽³⁾	40,306	33,958	568,444	266,558	154,039	107,743	86,410	403,378	191,289	114,364	83,767	70,156
Proved Plus Probable Undeveloped ⁽²⁾⁽³⁾⁽⁷⁾	84,147	73,565	1,018,007	539,258	320,324	206,558	140,459	757,629	404,046	241,134	155,455	104,923
Total Possible ⁽⁴⁾	25,714	21,425	392,227	139,383	67,678	43,387	33,241	278,509	99,304	49,235	32,557	25,703
Proved Plus Probable Plus Possible Undeveloped ⁽²⁾⁽³⁾⁽⁴⁾⁽⁷⁾	109,861	94,990	1,410,234	678,641	388,002	249,945	173,700	1,036,138	503,350	290,369	188,012	130,626

Supplemental Information Regarding the Corporation's Crude Oil and Natural Gas Reserves

The following is a summary of the crude oil and natural gas reserves and the value of future net revenue of the Corporation as at December 31, 2006 as evaluated by GLJ in the Connacher GLJ Report. The Connacher 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 and constant price evaluations is included in the notes set forth on page 14 of this Annual Information Form.

**CRUDE OIL AND NATURAL GAS RESERVES
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)	Gross ⁽¹⁾ (mmcf)	Net ⁽¹⁾ (mmcf)	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)
Proved Developed Producing ⁽²⁾⁽⁵⁾	2,106	1,742	21,524	17,607	1	1
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	-	-	3,167	2,615	-	-
Proved Undeveloped ⁽²⁾⁽⁷⁾	315	240	-	-	-	-
Total Proved ⁽²⁾	2,421	1,983	24,691	20,221	1	1
Total Probable ⁽³⁾	786	632	8,769	7,158	-	-
Total Proved Plus Probable ⁽²⁾⁽³⁾	3,207	2,615	33,460	27,379	2	1

**NET PRESENT VALUE OF FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

	Before Deducting Income Taxes					After Deducting Income Taxes				
	Discounted At					Discounted At				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved Developed Producing ⁽²⁾⁽⁵⁾	159,543	127,039	105,942	91,289	80,557	150,364	120,756	101,435	87,927	77,968
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	15,781	12,553	10,236	8,518	7,209	11,169	8,884	7,241	6,021	5,092
Proved Undeveloped ⁽²⁾⁽⁷⁾	7,963	6,541	5,493	4,698	4,077	5,584	4,616	3,890	3,333	2,896
Total Proved ⁽²⁾	183,286	146,133	121,672	104,504	91,844	167,117	134,255	112,566	97,282	85,956
Total Probable ⁽³⁾	73,053	45,012	30,739	22,557	17,433	52,547	32,104	21,850	16,022	12,389
Total Proved Plus Probable ⁽²⁾⁽³⁾	256,339	191,145	152,411	127,062	109,277	219,665	166,359	134,416	113,303	98,345

**CRUDE OIL AND NATURAL GAS RESERVES
BASED ON CONSTANT PRICES AND COSTS⁽⁸⁾**

	Light/Medium Crude Oil		Natural Gas		Natural Gas Liquids	
	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)	Gross ⁽¹⁾ (mmcf)	Net ⁽¹⁾ (mmcf)	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)
Proved Developed Producing ⁽²⁾⁽⁵⁾	2,125	1,759	21,531	17,611	1	1
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	-	-	3,167	2,615	-	-
Proved Undeveloped ⁽²⁾⁽⁷⁾	315	240	-	-	-	-
Total Proved ⁽²⁾	2,440	1,999	24,698	20,226	1	1
Total Probable ⁽³⁾	794	640	8,769	7,157	-	-
Total Proved Plus Probable ⁽²⁾⁽³⁾	3,234	2,639	33,467	27,383	2	1

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

	Before Deducting Income Taxes					After Deducting Income Taxes				
	Discounted At					Discounted At				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved Developed Producing ⁽²⁾⁽⁵⁾	127,893	103,715	87,603	76,174	67,665	127,532	103,517	87,491	76,109	67,627
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	10,939	8,770	7,194	6,012	5,104	7,767	6,558	5,610	4,852	4,236
Proved Undeveloped ⁽²⁾⁽⁷⁾	7,963	6,544	5,499	4,706	4,087	5,552	4,651	3,981	3,467	3,060
Total Proved ⁽²⁾	146,795	119,029	100,296	86,892	76,856	140,850	114,726	97,083	84,428	74,923
Total Probable ⁽³⁾	52,668	34,316	24,358	18,366	14,473	38,404	24,590	17,296	12,983	10,211
Total Proved Plus Probable ⁽²⁾⁽³⁾	199,462	153,345	124,654	105,257	91,329	179,254	139,316	114,379	97,410	85,134

Oil and Gas Resources

The Connacher GLJ Report also provided calculations of Contingent Resources comprised of "Low Estimate Resources (>15 metre Pay) - higher certainty", together with "Best Estimate Resources (13 metre Pay) - likely certainty" and "High Estimate Resources (>10 metre Pay) - lower certainty". Contingent Resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from known accumulations but are not currently economic. Low Estimate recoverable resources are comprised of mapped original oil-in-place assigned to Pod One (>15 metre Pay) with a lower recovery factor than are applied to the estimate of 2P reserves. Best Estimate Resources are comprised of 2P remaining recoverable reserves together with an estimate of recoverable resources attributable to five other pods on Connacher's lands. High Estimate Resources (lower certainty) include 3P recoverable reserves at Pod One together with recoverable resources at the other five Pods on Connacher's acreage, but with a larger aerial extent and a higher recovery factor than attributable under the Best Estimate Category.

Only Pod One had sufficient well and seismic control to warrant the assignment of reserves. The other five pods had insufficient drilling density, seismic mapping or project definition at December 31, 2006 to be categorized as reserves at this time. Additional drilling and seismic activity could result in upgrading these to reserve status over time. In the interim, a range of Contingent Resources was assigned to reflect uncertainties. The GLJ Connacher Report also recognized Best Estimate and High Estimate Prospective Resources attributable to undiscovered pods, utilizing average parameters from six identifiable pods, including Pod One. Prospective Resources are those quantities of oil and gas estimated on a given date to be potentially recoverable from undiscovered accumulations. If discovered, they would be technically and economically viable to recover. There is no certainty that the Prospective Resources will be discovered. This year, calculations of the present value of the future cash flow from remaining recoverable reserves, and, remaining recoverable resources (Contingent and Prospective) were included for the total Great Divide lands, not just Pod One.

Marketable Reserves, Resources	Total Company Interest (mmbbl)		Net After Royalty (mmbbl)		Future Net Revenue		
					Before Tax Present Value at 0% M\$	Before Tax Present Value at 5% M\$	Before Tax Present Value at 10% M\$
					Bitumen	Oil Equivalent	Bitumen
1P Reserves and Low Estimate Contingent Resources	70,533	70,533	65,144	65,144	766,390	437,718	243,198
2P Reserves and Best Estimate Contingent Resources	187,818	187,818	167,317	167,317	2,884,883	1,216,744	584,014
3P Reserves and High Estimate Contingent Resources	265,723	265,723	235,115	235,115	4,319,122	1,742,767	813,795
1P Reserves and Low Estimate Total Recoverable Resources	110,477	110,477	99,522	99,522	1,392,950	803,222	486,727
2P Reserves and Low Estimate Total Recoverable Resources	260,625	260,625	232,417	232,417	3,872,084	1,661,404	778,093
3P Reserves and Low Estimate Total Recoverable Resources	478,953	478,953	423,708	423,708	8,058,038	2,898,700	1,245,053
Total	1,374,129	1,374,129	1,223,223	1,223,223	21,293,467	8,760,555	4,150,880

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.

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 follows:

<u>Name and Municipality of Residence</u>	<u>Positions Held</u>	<u>Principal Occupation During the Preceding Five Years</u>	<u>Director Since</u>
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. President of Gusella Oil Investments Limited, an inactive private investment corporation.	May 30, 2001
Charles W. Berard ⁽³⁾⁽⁵⁾ Calgary, Alberta Canada	Director	Partner, Macleod Dixon LLP, a law firm.	May 30, 2001
D. Hugh Bessell ⁽¹⁾⁽²⁾⁽³⁾⁽⁴⁾ Toronto, Ontario Canada	Director	Businessman. Prior thereto, Deputy Chairman and Chief Operating Officer of KPMG LLP.	December 1, 2005
Colin M. Evans ⁽¹⁾⁽²⁾⁽⁴⁾⁽⁵⁾ Calgary, Alberta Canada	Director	Vice President, Finance, Milestone Exploration Inc., a private oil and natural gas exploration and production company. President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations from 1994 to 2004.	April 5, 2004
Stewart D. McGregor ⁽²⁾⁽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 ⁽¹⁾⁽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
Richard R. Kines Calgary, Alberta Canada	Vice President, Finance and Chief Financial Officer	Vice President, Finance and Chief Financial Officer since December 2004 and Chief Financial Officer of Connacher since June 2003. Prior thereto, financial consultant of Connacher since April 2002.	-
Peter D. Sametz Calgary, Alberta Canada	Executive Vice President and Chief Operating Officer	Executive Vice President and Chief Operating Officer of Connacher since December 2004. From February 2004, Vice President Operations of Connacher. Prior thereto, simultaneously Chief Operating Officer and a director of Surge Petroleum Inc., a public oil company listed on the TSX Venture Exchange since July 2000 and a Principal of Inline Petroleum Management Incorporated from 1997 to February 2004.	-

Name and Municipality of Residence	Positions Held	Principal Occupation During the Preceding Five Years	Director Since
Timothy J. O'Rourke Calgary, Alberta Canada	Vice President, Oil Sands Operations	Vice President, Oil Sands Operations of Connacher since December 2004. Prior thereto, General Manager, Production of Connacher since August 2001. Prior thereto, consultant to Connacher.	-
Stephen A. Marston Calgary, Alberta Canada	Vice President, Exploration	Vice President, Exploration of Connacher since January 2005. Prior thereto, Chief Geophysicist of Real Resources Inc. since January 2001.	-
Cameron M. Todd Calgary, Alberta Canada	Vice President, Refining and Marketing	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.	-
Darren P. Jackson Calgary, Alberta Canada	Vice President, Operations	Vice President, Operations of Connacher since November 2006. Prior thereto, Production Manager of Canetic Resources Trust from April 2003 to November 2006 and prior thereto Production Engineer of Encana Corporation from May 1994 to April 2003.	-
Stephen J. De Maio Calgary, Alberta Canada	Vice President, Project Development	Vice President, Project Development of Connacher since November 2006 and Consultant Engineer of Connacher from March 2006 to November 2006. Prior thereto, Consultant Engineer of Total E&P Canada from August 2005 to August 2006 and of Deer Creek Energy Limited from March 2005 to August 2005. Chief Executive Officer of Efficient Energy Ltd. from December 2000 to March 2005.	-
Grant D. Ukrainetz Calgary, Alberta Canada	Treasurer	Treasurer of Connacher since June 2006. Prior thereto, Supervisor, Treasury of Talisman Energy Inc. and prior thereto Treasury and Risk Management Analyst of Talisman Energy Inc.	-
Jennifer K. Kennedy Calgary, Alberta Canada	Secretary	Partner, Macleod Dixon LLP, a law firm, since January 2000.	-

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 23, 2007, the directors and executive officers of Connacher, as a group, beneficially owned, directly or indirectly, or exercised control or direction over 3,641,787 Common Shares constituting approximately one percent of the issued and outstanding Common Shares.

AUDIT COMMITTEE

Composition and Qualifications

The Corporation's Audit Committee consists of three outside and independent directors, Messrs. Bessell, Chair, Seth and Evans. The Board has determined that all of the members of the Audit Committee are "financially literate" as defined in Multilateral 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".

W.C. (Mike Seth)

Mr. Seth is an engineer by training and holds a Bachelors of Science Degree in Mechanical Engineering from the University of British Columbia. He is President of Seth Consultants Ltd., a private consulting firm, and prior thereto he served as Chairman of McDaniel & Associates Consultants Ltd., one of the pre-eminent oil and natural gas reserve evaluators in Canada and internationally. Prior to becoming Chairman of McDaniel Mr. Seth was President and Managing Director of McDaniel for 37 years. Mr. Seth serves on the boards of various other junior oil and gas companies (reporting and non-reporting issuers) and of one senior oil and gas income fund. He is also the founder and a director of Energy Navigator Inc., a private software development firm servicing the petroleum industry.

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 Vice President, Finance of Milestone Exploration Inc., a private oil and natural gas exploration and production company. From 1994 to 2004 Mr. Evans was the President of Evans & Co. Inc., a private consulting corporation providing financial and operating advisory services to oil and gas corporations.

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

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 when 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 paid to Deloitte & Touche LLP, the external auditor of the Corporation, for the years ended December 31, 2006 and December 31, 2005:

	<u>2006</u>	<u>2005</u>
Audit fees	\$ 136,943	\$ 75,000
Review engagement fees	-	20,000 ⁽¹⁾
Tax fees	-	1,750 ⁽²⁾
All other related fees ⁽³⁾	88,301	84,057
TOTAL	<u>\$ 225,244</u>	<u>\$ 180,807</u>

Notes:

- (1) Review of the Corporation's interim financial statements.
- (2) Tax planning and compliance.
- (3) Services related to corporate and property acquisitions and prospectus financings.

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, 2006, the Corporation had 39 employees at its head office in Calgary. The Corporation has one field office, with one employee and three contract operators.

DESCRIPTION OF SHARE CAPITAL

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, of which as at December 31, 2006, 197,894,015 Common Shares and no Preferred Shares were issued and outstanding. The following is a summary of the rights, privileges, restrictions and conditions attaching to the Common Shares and Preferred Shares of the Corporation.

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.

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.

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, 2006.

	Volume	Monthly Price Range	
		High	Low
	(000's)	(\$)	(\$)
January	58,320,073	6.07	3.47
February	57,514,454	5.84	4.29
March	32,349,746	5.23	4.64
April	31,868,409	5.05	3.52
May	27,584,050	4.70	3.60
June	20,894,660	4.42	3.10
July	14,235,409	4.55	3.68
August	13,548,578	4.33	3.76
September	21,065,089	4.13	3.09
October	20,468,912	4.43	3.17
November	13,414,044	4.21	3.51
December	12,561,871	3.78	3.37

TRANSFER AGENT AND REGISTRAR

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

RISK FACTORS

The Corporation

An investment in the Corporation is subject to certain risks related to the nature of the Corporation's business and its present stage of development. There are numerous factors which may affect the success of the Corporation's business which are beyond the Corporation's control including local, national and international economic and political conditions. The Corporation's business involves a high degree of risk which a combination of experience, knowledge and careful evaluation may not overcome. The Corporation's investment in Petrolifera exposes the Corporation to risks which may not exist for domestic operations such as political and currency risks. The Corporation has a limited history of operations and earnings and there can be no assurance that the Corporation's business will be successful or profitable or that commercial quantities of oil and natural gas will be discovered by the Corporation. The Corporation has not paid any dividends and it is unlikely to pay dividends in the immediate or foreseeable future.

Additional Financing

Depending on future exploration, development, acquisition and divestiture plans, the Corporation will require additional financing. The ability of the Corporation to arrange such financing in the future will depend in part upon the prevailing capital market conditions as well as the business performance of the Corporation. There can be no assurance that the Corporation will be successful in its efforts to arrange additional financing on terms satisfactory to the Corporation. If additional financing is raised by the issuance of shares from treasury of the Corporation, control of the Corporation may change and 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.

Industry Conditions

The oil and gas industry is intensely competitive and the Corporation competes with other companies which possess greater technical and financial resources. Many of these competitors not only explore for and produce oil and natural gas but, also carry on refining operations and market petroleum and other products on an international basis. Oil and gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and invasion of water into producing formations.

The marketability and price of oil and natural gas which may be acquired or discovered by the Corporation will be affected by numerous factors beyond the control of the Corporation. The ability of the Corporation to market any natural gas discovered may depend upon its ability to acquire space on pipelines which deliver natural gas to commercial markets. The Corporation is also subject to market fluctuations in the prices of oil and natural gas, uncertainties related to the delivery and proximity of its reserves to pipelines and processing facilities and extensive government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and gas and many other aspects of the oil and gas business. The Corporation is also subject to a variety of waste disposal, pollution control and similar environmental laws.

The oil and gas industry in Canada, including the oil sands industry, operates under 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, as well as other matters. The industry is also subject to regulation by 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.

The oil and natural gas industry is subject to varying environmental regulations in each of the jurisdictions in which the Corporation may operate. Environmental regulations place restrictions and prohibitions on emissions of various substances produced concurrently with oil and natural gas and can impact on the selection of drilling sites and facility locations, potentially resulting in increased capital expenditures.

Stage of Development of Connacher

There is a risk that design and construction of the facilities and infrastructure to support the Corporation's Great Divide oil sands project will not be completed on time, on budget or at all. Additionally, there is a risk that the Great Divide project may have delays, interruptions of operations or increased costs due to many factors, including, without limitation:

- inability to attract or retain sufficient numbers of qualified workers;

- breakdown or failure of equipment or processes;
- construction performance falling below expected levels of output or efficiency;
- design errors;
- non-performance by, or financial failure of, third-party contractors;
- labour disputes, disruptions or declines in productivity;
- increases in materials or labour costs;
- conditions imposed by regulatory approvals;
- delays induced by weather;
- disruption or delays in availability of transportation services;
- errors in construction;
- changes in Great Divide's scope;
- unforeseen site surface or subsurface conditions;
- transportation or construction accidents;
- permit requirement violation;
- reservoir performance;
- energy supply disruption; and
- shortages of or delays in accessing drilling rigs and services.

The Great Divide project is not being constructed on a turn-key basis. Additionally, given the state of development of the Great Divide project, various changes to the project may be made. Based upon current scheduling, the project is not expected to start commercial SAGD operations until mid-summer 2007. The information contained herein, including, without limitation, reserve and economic evaluations, is conditional upon receipt of all regulatory approvals and no material changes being made to the project or its scope. The industry is entering a period where unprecedented oil sands development and industrial activity is planned at a time when activity in many other sectors is also high. Connacher will need to compete for equipment, supplies, services, and labour in this environment which could result in increased costs, shortages of goods and services that delay progress, or both. Increased competition for equipment, materials and labour may result in increased costs that could have a material adverse effect on Connacher's business, financial condition or results of operations. As such, there are risks associated with project cost estimates provided by Connacher. Cost estimates are provided prior to completion of final scope design and detailed engineering needed to reduce the margin of error. Accordingly, actual costs may vary from estimates and these differences may be material.

Operating Costs

The operating costs of the Great Divide project, which have the potential to vary considerably, are significant components of the cost of production of the petroleum products produced by the Great Divide project. The operating costs of the Great Divide project may vary considerably during the operating period. The factors which could affect operating costs include, without limitation;

- the amount and cost of labour to operate the Great Divide project;
- the cost of catalyst and chemicals;
- the actual steam oil ratio required to operate the SAGD well pairs;
- the cost of natural gas and electricity;
- power outages, particularly in winter when freeze-ups could occur;
- produced sand causing issues of erosion, hot spots and corrosion;
- reliability of the facilities;
- the maintenance cost of the facilities;
- the cost to transport sales products and the cost to dispose of certain by-products; and
- the cost of insurance; and
- catastrophic events such as fires, earthquakes, storms or explosions.

Connacher's earnings may be reduced if increases in operating costs are incurred.

Infrastructure for the Great Divide Project

Connacher will depend, to a large extent, on third party designers, contractors and suppliers to design and construct the necessary facilities and infrastructure for the Great Divide project. Connacher also anticipates that it will rely on certain infrastructure owned and operated or to be constructed by others, including, without limitation, pipelines for the transportation of diluent and produced bitumen to the market, natural gas, water source and disposal pipelines and electrical grid transmission lines for the provision and/or sale of electricity to Connacher. The failure of any or all of these third parties to supply utilities, services or construct the infrastructure required to complete the Great Divide project on a timely basis and on acceptable commercial terms will negatively impact Connacher's operation and financial results.

In-situ Extraction

Current SAGD technologies for in-situ recovery of heavy oil and bitumen are energy intensive, requiring significant consumption of natural gas and 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 performance of the reservoir can also impact the timing and levels of production using this technology. Commercial application of this technology 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.

Seasonality of Refining Operations and Sales

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 our asphalt tend to be higher in the summer and lower in the colder seasons and during the winter most of the Refinery's asphalt production is stored in tankage for sale in the subsequent summer. Seasonal factors also affect gasoline (higher demand in summer months) and distillate and diesel (higher winter demand). As a result, inventory levels, sales volumes and prices can be expected to fluctuate on a seasonal basis.

Recovery of Bitumen

Recovering bitumen from oil sands involves particular risks and uncertainties. The project is susceptible to loss of production, slowdowns, or restrictions on its ability to produce higher value products due to the interdependence of its component systems. 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 Connacher's facilities or wells and liability to third parties against which Connacher may not be able to fully insure or may elect not to insure because of high premium costs or for other reasons. The costs associated with synthetic crude oil production are largely fixed and, as a result, operating costs per unit are largely dependent on levels of production.

Access to Diluent Supplies at Favourable Prices

Bitumen is characterized by high specific gravity or weight and low viscosity or resistance to flow. Among its other uses, diluent is required to facilitate the transportation of bitumen. A shortfall in the supply of diluent may cause its price to increase thereby increasing the cost to transport bitumen to market and correspondingly increasing Connacher's operating cost, decreasing its net revenues and negatively impacting the overall profitability of the Great Divide oil sands project.

Transportation

It is expected that the Corporation will initially truck bitumen to market. Normal hazards associated with trucking include proximity to a busy highway (Highway 63) and traffic.

Vehicular traffic to and from the Great Divide site will be via Highway 63 for the life of the project. Collisions between vehicles and wildlife remain a significant hazard.

Travel by air into the Fort McMurray area is increasing dramatically as oil sands development continues. This, too, is an emerging issue for all operators.

Operational Hazards

The operation of the Great Divide project and the other oil and gas properties of the Corporation 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 project could be interrupted by natural disasters or other events beyond the control of the Corporation. Losses and liabilities arising from uninsured or under insured events could have a material adverse effect on the project and on the Corporation's business, financial condition and results of operations.

Abandonment and Reclamation Costs

Connacher will be responsible for compliance with terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of the Great Divide project and reclamation of its lands at the end of its economic life, which abandonment and reclamation costs 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. In the future Connacher 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.

The Corporation has not recorded an asset retirement obligation for the Montana 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.

Independent Reviews

Although third parties have prepared reviews, reports and projections relating to the viability and expected performance of the Great Divide project, it cannot be assured that these reports, reviews and projections and the assumptions on which they are based will, over time, prove to be accurate.

Volatility of Refinery Margins

Connacher 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 and gasoline. Margin volatility is influenced by overall marketplace competitiveness, 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

An initiative of the U.S. Environmental Protection Agency on gasoline would impose reductions in benzene content, volatility, sulphur, and other parameters. These new requirements, other requirements of the U.S. Federal Clean Air Act, or other presently existing or future environmental regulations could require Connacher to expend substantial amounts to permit MRC to produce products that meet such requirements.

Terrorist Attacks and the Threat of Terrorist Attacks

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 energy transportation industry in general, and on Connacher in particular, is not known at this time. The possibility that infrastructure facilities may be direct targets of, or indirect casualties of, an act of terror and the implementation of security measures as a precaution against possible terrorist attacks will result in increased costs to Connacher's business.

Debt Service

Connacher intends to continue to use its credit facility and term debt to finance its conventional oil sands and refining expenditures. Restrictive covenants governing Connacher's debt will limit the amount of debt that Connacher may incur. Connacher's ability to make scheduled repayments or to re-finance its debt obligations will depend upon its financial and operating performance, which in turn will depend upon prevailing industry and general economic conditions which are beyond Connacher's control. There can be no assurance that Connacher's operating performance, cash flow and capital resources will be sufficient to service and/or repay its debt in the future, in which case Connacher may be required to sell assets to repay its debt, defer capital expenditures or raise additional equity, to the extent available. Connacher has deposited US\$14 million of the proceeds of the US\$180 million term debt arranged in 2006 to service this term debt until the expected start-up date of Pod One.

Access to Human Resources

The labour force in the Fort McMurray and surrounding area is limited and the inability to access the necessary skilled labourers to construct and operate Connacher's Great Divide project could have an adverse affect on Connacher's development plans. In addition, rising personnel costs could result in increases in general and administrative expenses and labour costs associated with the development of the project.

Competition

When operations commence, the Great Divide project will compete with other producers of bitumen and conventional producers of oil and gas. The petroleum industry also competes with other industries in supplying energy, fuel and related products to consumers.

A number of companies other than Connacher have announced plans to enter the oil sands business, or expand existing operations. Expansion of existing operations and development of new projects could materially increase the supply of bitumen in the marketplace. Depending on the levels of future demand, increased supplies could have a negative impact on prices.

Royalty Regime

In the event that the Great Divide project is developed and becomes operational, Connacher's revenue and expenses will be directly affected by the royalty regime applicable to the Great Divide project. The economic benefit of future capital expenditures at Great Divide is, in many cases, dependent on a satisfactory royalty regime. There can be no assurance that the federal government and the Province of Alberta will not adopt a new royalty regime which will make capital expenditures uneconomic or that the regime currently in place will remain unchanged.

Risks of Foreign Investment

Through its significant equity interest in Petrolifera, the Corporation is 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 or prospectively in 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 the Corporation.

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 natural gas produced by Petrolifera in Argentina must be sold locally at rates that may not be comparable to international rates.

Need to Add Reserves

The Corporation's oil and natural gas reserves and production, and therefore its cash flows and earnings are highly dependent upon the Corporation developing and increasing its current reserve base and discovering or acquiring additional reserves. Without the addition of reserves through exploration, acquisition or development activities, the Corporation's reserves and production will decline over time as reserves are depleted. 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 oil and natural gas reserves will be impaired. There can be no assurance that the Corporation will be able to find and develop or acquire additional reserves to replace production at commercially feasible costs.

Environmental Regulation and Risks

Extensive national, state and local environmental laws and regulations in Canada and in foreign jurisdictions affect nearly all of the operations of the Corporation. These laws and regulations set various standards regulating certain aspects of health and environmental quality, provide for penalties and other liabilities for the violation of such standards and establish in certain circumstances obligations to remediate current and former facilities and locations where operations are or were conducted. In addition, special provisions may be appropriate or required in environmentally sensitive areas of operation. There can be no assurance that the Corporation will not incur substantial financial obligations in connection with environmental compliance.

The construction, operation and decommissioning of the Corporation's oil sands projects and reclamation of the projects' land are conditional upon various environmental and regulatory approvals issued by governmental authorities. There is no assurance approvals will be issued for future oil sands projects, or once issued renewed, or that they will not contain terms and conditions which make the project uneconomic or cause the Corporation to significantly alter such projects.

Significant liability could be imposed on the Corporation for damages, cleanup costs or penalties in the event of certain discharges into the environment, environmental damage caused by previous owners of properties purchased by the Corporation or non-compliance with environmental laws or regulations. Such liability could have a material adverse effect on the Corporation. Moreover, the Corporation cannot predict what environmental legislation or regulations will be enacted in the future or how existing or future laws or regulations will be administered or enforced. For example, water usage, water table and potable water issues in the Fort McMurray area are an emerging environmental and regulatory concern. Compliance with more stringent laws or regulations, or more vigorous enforcement policies of any regulatory authority, could in the future require material expenditures by the Corporation for the installation and operation of systems and equipment for remedial measures, any or all of which may have a material adverse effect on the Corporation. The Corporation has developed a restoration plan that has been approved.

Kyoto Accord

Canada is a signatory to the United Nations Framework Convention on Climate Change 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 so-called "greenhouse gases". The Government of Canada has put forward a Climate Change Plan for Canada which suggests further legislation will set greenhouse gases emission reduction requirements for various industrial activities, including oil and gas production. Future federal legislation, together with existing provincial emission reduction legislation, such as in Alberta's *Climate Change and Emissions Management Act*, may require the reduction of emissions and/or emissions intensity from the Corporation's oil and gas exploration and development activities. The direct or indirect costs of such legislation may adversely affect the Corporation's operations. No assurance can be given that future environmental approvals, laws or regulations will not adversely impact (i) the ability of the Corporation to conduct its operations or (ii) the Corporation's production or (iii) the Corporation's unit costs of production. Equipment from suppliers which can meet future emission standards may not be available on an economic basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or

provincial governments could pass legislation which would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, such as the Corporation. Mitigation of the risk of future legislative or regulatory limits on the emission of greenhouse gases may include the acquisition of emission reduction or off-set credits from third parties. However, emission reduction or off-set credits may not be available for acquisition by the Corporation or may not be available on an economic basis and may not be recognized or qualify under future legislative or regulatory regimes as mitigation for the emission of greenhouse gases by the Corporation.

Volatility of Oil and Gas Prices and Markets

The Corporation's financial condition, operating results and future growth are dependent on the prevailing prices for its oil and natural gas production. Historically, the markets for oil and natural gas have been volatile and such markets are likely to continue to be volatile in the future. Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes to the demand for oil and natural gas, whether the result of uncertainty or a variety of additional factors beyond the control of the Corporation. Any substantial decline in the prices of oil and natural gas could have a material adverse effect on the Corporation and the level of its oil and natural gas reserves. Additionally, the economics of producing from some wells may change as a result of lower prices, which could result in a suspension of production by the Corporation. No assurance can be given that oil and natural gas prices will be sustained at levels which will enable the Corporation to operate profitably. From time to time the Corporation may avail itself of forward sales or other forms of hedging activities with a view to mitigating its exposure to the risk of price volatility.

Reserve and Resource Estimates

There are numerous uncertainties inherent in estimating quantities of proved, probable and possible reserves and resources and cash flows to be derived therefrom, including many factors beyond the control of the Corporation. The reserve, resource and cash flow information set forth in this Annual Information Form 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, 2006. These evaluations include a number of assumptions relating to factors such as initial production rates, production decline rates, ultimate recovery of reserves, timing and amount of capital expenditures, marketability of production, future prices of oil and natural gas, operating costs, abandonment and salvage values, royalties and other government levies that may be imposed over the producing life of the reserves. These assumptions were based on price forecasts in use at the date of the relevant evaluations were prepared and many of these assumptions are subject to change and are beyond the control of the Corporation. Actual production and cash flows 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 and upon analogy to similar types of reserves, 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.

Reserve and resource estimates may require revision based on actual production experience. Such figures have been determined based upon assumed oil prices and operating costs. Market price fluctuations of oil 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 the Great Divide project in any particular period.

The present value of estimated future net cash flows referred to herein should not be construed as the current market value of estimated oil and natural gas reserves attributable to the Corporation's properties. The estimated discounted future cash flow 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 cash flows will also be affected by factors such as the amount and timing of actual production, supply and demand for oil and natural gas, curtailments or increases in consumption by purchasers and changes in governmental regulations or taxation.

Title to Properties

Although title reviews will be done according to industry standards prior to the purchase of most oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the claim of the Corporation which could result in a reduction of the revenue received by the Corporation.

Potential Conflicts of Interest

There are potential conflicts of interest to which some of the directors and officers of the Corporation will be subject in connection with the operations of the Corporation. Some of the directors and officers 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. Additionally, certain officers and directors of the Corporation are also officers and directors of Petrolifera and 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.

Exchange Rate Risk

Revenue received from the sale of crude oil is generally referenced to a price denominated in US\$. All of MRC's business is conducted in US\$. As the Corporation reports its operating results in CDN\$, fluctuations in product pricing and fluctuations in the rate of exchange between the US\$ and CDN\$ would affect reported revenues and reported results. Additionally, the Corporation maintains term debt denominated in US\$. To mitigate these risks, the Corporation has, in the past, fixed the price of a portion of its crude oil sales in CDN\$.

Aboriginal Claims

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 the Great Divide project and most of the other oil sands operations in Alberta are located. Such claims, if successful, could have a significant adverse effect on Connacher and the Great Divide project. Connacher continues to consult with, and work with, Aboriginal groups in the Great Divide area.

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 or 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, 2006, which are contained in the Annual Report of the Corporation for the year ended December 31, 2006.

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**

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, 2006. The reserves data consist of the following:
 - (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006, using forecast prices and costs; and
 - (ii) the related estimated future net revenue; and
 - (b) (i) proved oil and gas reserves estimated as at December 31, 2006, using constant prices and costs; and
 - (ii) the related estimated future net revenue.

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, 2006, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors.

Independent Qualified Reserves Evaluator	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate -\$M)			
			Audited	Evaluated	Reviewed	Total
GLJ Petroleum Consultants	March 7, 2007	Canada	-	\$528,809	-	\$528,809

5. In our opinion, the reserves 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.

EXECUTED as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, March 9, 2007.

(Signed) "Terry L. Aarsby"
Terry L. Aarsby, P. Eng.
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 consist of the following:

- (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2006 using forecast prices and costs; and
- (ii) the related estimated future net revenue; and
- (b) (i) proved oil and gas reserves estimated as at December 31, 2006 using constant prices and costs; and
- (ii) the related estimated future net revenue.

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 the reserves data and other oil and gas information;
- (b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and
- (c) the content and filing of this report.

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

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

(signed) *D. Hugh Bessell*
D. Hugh Bessell
Director

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

(signed) *Stewart D. McGregor*
Stewart D. McGregor
Director

March 23, 2007

SCHEDULE C

CONNACHER'S 26% INTEREST IN PETROLIFERA'S OIL AND GAS RESERVES AND FUTURE NET REVENUE

The following is a summary of the Corporation's 26% interest in Petrolifera's oil and gas reserves and future net revenue as at December 31, 2006 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).

RESERVES DATA - FORECAST PRICES AND COSTS

**CRUDE OIL AND NATURAL GAS RESERVES
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

	Light/Medium Crude Oil		Natural Gas		Oil Equivalent	
	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)	Gross ⁽¹⁾ (mmcf)	Net ⁽¹⁾ (mmcf)	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)
Proved Developed Producing ⁽²⁾⁽⁵⁾	1,338	1,158	2,467	2,134	1,749	1,513
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	37	32	-	-	37	32
Proved Undeveloped ⁽²⁾⁽⁷⁾	1,361	1,177	1,239	1,072	1,567	1,356
Total Proved ⁽²⁾	2,736	2,367	3,707	3,206	3,353	2,901
Total Probable ⁽³⁾	2,343	2,027	3,781	3,271	2,973	2,572
Total Proved Plus Probable ⁽²⁾⁽³⁾	5,079	4,394	7,488	6,477	6,326	5,473

**NET PRESENT VALUE OF FUTURE NET REVENUE
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

	Before Deducting Income Taxes					After Deducting Income Taxes				
	Discounted At					Discounted At				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved Developed Producing ⁽²⁾⁽⁵⁾	44,450	40,894	38,031	35,657	33,646	32,908	30,096	27,850	26,002	24,447
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	988	809	684	593	524	644	522	434	370	322
Proved Undeveloped ⁽²⁾⁽⁷⁾	36,738	30,337	25,384	21,463	18,301	23,873	19,323	15,828	13,079	10,875
Total Proved ⁽²⁾	82,176	72,040	64,099	57,713	52,471	57,425	49,940	44,112	39,451	35,644
Total Probable ⁽³⁾	81,715	64,746	52,691	43,834	37,147	53,126	41,848	33,860	28,011	23,608
Total Proved Plus Probable ⁽²⁾⁽³⁾	163,891	136,786	116,790	101,547	89,618	110,551	91,788	77,973	67,462	59,252

**FUTURE NET REVENUE
(UNDISCOUNTED)
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

	Revenue ⁽¹⁾ (M\$)	Royalties ⁽¹⁾ (M\$)	Operating Expenses (M\$)	Capital Costs (M\$)	Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Total Proved ⁽²⁾	134,800	18,198	23,398	10,720	307	82,177	24,752	57,425
Total Proved Plus Probable ⁽²⁾⁽³⁾	251,817	33,995	41,777	11,786	367	163,891	53,341	110,550

**FUTURE NET REVENUE BY PRODUCTION GROUP
BASED ON FORECAST PRICES AND COSTS⁽⁹⁾**

Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year) (\$'000's)
	Total Proved ⁽²⁾
Light and medium crude oil	62,545
Associated gas and non-associated gas	1,554
Total Proved Plus Probable ⁽²⁾⁽³⁾	113,174
Light and medium crude oil	113,174
Associated gas and non-associated gas	3,616

RESERVES DATA - CONSTANT PRICES AND COSTS

CRUDE OIL AND NATURAL GAS RESERVES BASED ON CONSTANT PRICES AND COSTS⁽⁸⁾

	Light/Medium Crude Oil		Natural Gas		Oil Equivalent	
	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)	Gross ⁽¹⁾ (mmcf)	Net ⁽¹⁾ (mmcf)	Gross ⁽¹⁾ (mdbl)	Net ⁽¹⁾ (mdbl)
Proved Developed Producing ⁽²⁾⁽⁵⁾	1,339	1,159	2,469	2,136	1,751	1,515
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	38	33	-	-	38	33
Proved Undeveloped ⁽²⁾⁽⁷⁾	1,367	1,182	1,243	1,076	1,574	1,361
Total Proved ⁽²⁾	2,744	2,373	3,713	3,212	3,362	2,908
Total Probable ⁽³⁾	2,357	2,039	3,791	3,279	2,989	2,585
Total Proved Plus Probable ⁽²⁾⁽³⁾	5,101	4,412	7,504	6,491	6,351	5,494

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

	Before Deducting Income Taxes					After Deducting Income Taxes				
	Discounted At					Discounted At				
	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)	0% (M\$)	5% (M\$)	10% (M\$)	15% (M\$)	20% (M\$)
Proved Developed Producing ⁽²⁾⁽⁵⁾	43,520	40,211	37,481	35,188	33,229	32,222	29,603	27,464	25,679	24,165
Proved Developed Non-Producing ⁽²⁾⁽⁶⁾	1,072	866	725	624	549	761	591	479	401	345
Proved Undeveloped ⁽²⁾⁽⁷⁾	38,434	31,819	26,666	22,571	19,264	24,990	20,298	16,670	13,806	11,506
Total Proved ⁽²⁾	83,026	72,896	64,872	58,384	53,042	57,972	50,492	44,613	39,886	36,015
Total Probable ⁽³⁾	82,928	65,572	53,286	44,287	37,507	53,916	42,390	34,253	28,310	23,846
Total Proved Plus Probable ⁽²⁾⁽³⁾	165,955	138,467	118,159	102,671	90,549	111,889	92,882	78,866	68,196	59,862

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

	Revenue (M\$)	Royalties (M\$)	Operating Expenses (M\$)	Capital Costs (M\$)	Abandonment Costs (M\$)	Future Net Revenue Before Income Taxes (M\$)	Income Taxes (M\$)	Future Net Revenue After Income Taxes (M\$)
Total Proved ⁽²⁾	134,264	18,126	22,156	10,699	257	83,026	25,054	57,972
Total Proved Plus Probable ⁽²⁾⁽³⁾	250,526	33,821	38,723	11,739	289	165,954	54,068	111,887

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

	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Year)
		(\$000's)
Total Proved ⁽²⁾	Light and medium crude oil	64,230
	Associated gas and non-associated gas	642
Total Proved Plus Probable ⁽²⁾⁽³⁾	Light and medium crude oil	116,665
	Associated gas and non-associated gas	1,494

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 90% 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 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.
- (8) The product prices used in the constant price and cost evaluations in the GLJ Report were as follows: (1) Light sweet crude oil price at Edmonton: \$73.16/bbl, (2) Natural gas at Spot Plant Gate: \$5.87/mmbtu and (3) Natural gas liquids (Edmonton butane): \$54.06/bbl.
- (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, 2006.

	<u>Inflation Rate</u>	<u>Exchange Rate</u>
	<u>%/year</u>	<u>\$US/\$Cdn</u>
Year Forecast		
2007	2.0	0.870
2008	2.0	0.870
2009	2.0	0.870
2010	2.0	0.870
2011	2.0	0.870
2012	2.0	0.870
2013	2.0	0.870
2014	2.0	0.870
2015	2.0	0.870
2016	2.0	0.870
2017	2.0	0.870
Thereafter	2.0	0.870

The crude oil price received by Petrolifera is based on the following formula: [(WTI - Quality Differential) x Price Factor /0.98 + Price Premium]/Exchange Rate

Where: WTI=WTI price limited by ceiling price of \$55.00/bbl
Quality Differential = 0.37
Price Factor = 0.68966
Price Premium (WTI \$55 to \$80/bbl) = WTI - 55) x 0.305

Forecast prices used in the above formula are as follows:

Year Forecast	<u>WTI</u>
	<u>\$US/bbl</u>
2007	62.00
2008	60.00
2009	58.00
2010	57.00
2011	57.00
2012	57.50
2013	58.50
2014	59.75
2015	61.00
2016	62.25
2017	63.50
2018	64.77
2019	66.07
2020	67.39
2021	68.73
2022	70.11
2023	71.51

Gas prices were forecast to be \$2.39/mmbtu in 2007 and to escalate at 2 percent per year thereafter. This forecast is based on gas marketing information provided by Petrolifera. 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 portion of the year ended December 31, 2006 during which Connacher consolidated Petrolifera's accounts with Connacher's financial results. See "General Development of the Business".

Property Acquisition Costs		Exploration Costs	Development Costs
(\$)		(\$)	(\$)
<u>Proved Properties</u>	<u>Unproved Properties</u>		
-	64,963	1,302,309	1,349,737

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 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 together with a copy of the minutes from such meetings. Where minutes have not yet been prepared, the Chair shall provide the Board with oral reports on the activities of the Committee. 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) 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;
- (e) 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;
- (f) 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;
- (g) review accounting, tax and financial aspects of the operations of the Corporation as the Committee considers appropriate; and
- (h) 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;
- (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.