



PRESS RELEASE

May 11, 2010

Connacher Oil and Gas Reports First Quarter 2010 (“Q1 2010”) Results; Algar Completed, Being Commissioned, Anticipate May 2010 Startup; Successful Great Divide Exploration Drilling Program; Cash Flow and Earnings Show Significant Improvement Over Q1 2009 and Q4 2009; Outlook Positive

Calgary, Alberta – Connacher Oil and Gas Limited (CLL: TSX) today announced its first quarter 2010 financial and operating results.

The period was highlighted by the continuing successful construction of Algar, the company’s second 10,000 bbl/d SAGD oil sands project on its Great Divide acreage in the Alberta oil sands. The plant is currently being commissioned and is expected to start up in the second half of May 2010. First production is anticipated during August 2010 after the normal 90 day steam circulation phase of the startup procedures. Thereafter rampup will occur through the end of 2010 and into 2011 and new production will materially impact on Connacher’s financial and operating results for the balance of this year and into 2011.

During the first quarter the company conducted an extensive and successful core hole drilling program on its 100 percent-owned Great Divide and 50 percent-owned Halfway Creek acreage blocks. Results will be incorporated along with the results of conventional drilling programs in a reserve report update to be prepared by GLJ Petroleum Consultants Ltd. (“GLJ”) for release in early July 2010.

We recently installed the first high temperature electrical submersible pump (“ESP”) at one of our wells at Great Divide Pod One. Production levels are increasingly stable at this site and expected to average over 8,500 barrels per day in 2010, supplemented by new production from Algar. Our full year capital budget for 2010, including outlays for Algar, now stands at \$247 million. Based on our outlook, it is management’s opinion that we have sufficient cash balances, anticipated cash flow from operations and unutilized and available lines of credit to meet all our capital and financial requirements for 2010.

As much of our capital program is now complete, our focus turns to the prospect of further expansions at Algar. To this end, we will shortly file our formal application (“EIA”) with a view to securing regulatory approval to increase capacity at Algar to 34,000 bbl/d of bitumen, thus increasing our total plant design capacity to 44,000 barrels per day. We anticipate this process will take approximately 18 months, such that our 300 day construction cycle may be initiated as early as late 2011. We anticipate a much lower level of capital outlays for our basic business activities in 2011 as we plan our Algar expansion primarily for 2012, with possible startup in 2013.

These results will be the subject of a Conference Call at 9:00 AM MT on May 12, 2010. To listen to or participate in the live conference call please dial either 1-647-427-7450 or 1-888-231-8191. A replay of the event will be available from Wednesday, May 12, 2010 at 12:00 MT until 21:59 MT on Wednesday, May 19, 2010. To listen to the replay please dial either 1-416-849-0833 or Toll Free at 1-800-642-1687 and enter the pass code 72048478. You can also listen to the conference call online, through the following webcast link: <http://www.newswire.ca/en/webcast/viewEvent.cgi?eventID=3057560>

Highlights

- Algar construction completed ahead of schedule and anticipated to be under budget; commissioning underway and bitumen production anticipated in second half of 2010
- Improved financial results; cash flow significantly higher; earnings reversal
- Hedge positions strengthened and
- Successful winter exploration program - reserve and resource estimates being updated.

Summary Results

Three months ended and as at March 31	2010	2009	% Change
FINANCIAL (\$000 except per share amounts)			
Revenues	\$118,411	\$61,757	92
Cash flow ⁽¹⁾	\$3,948	\$(4,692)	184
Per share, basic and diluted ⁽¹⁾	\$0.01	\$(0.02)	150
Net earnings (loss)	\$5,546	\$(46,844)	112
Per share, basic and diluted	\$0.01	\$(0.22)	105
Property and equipment expenditures	\$118,272	\$64,255	84
Cash on hand	\$118,382	\$96,220	23
Working capital	\$127,186	\$120,035	6
Long-term debt	\$851,978	\$803,915	6
Shareholders' equity	\$668,722	\$428,276	56
Total assets	\$1,707,123	\$1,385,674	23
OPERATIONAL			
Upstream daily production/sales volumes			
Bitumen (bbl/d)	6,936	6,170	12
Crude oil (bbl/d)	937	1,180	(21)
Natural gas (Mcf/d)	9,662	12,828	(25)
Equivalent (boe/d) ⁽²⁾	9,483	9,488	-
Upstream pricing ⁽³⁾			
Bitumen (\$/bbl)	\$51.98	\$22.45	132
Crude oil (\$/bbl)	\$71.08	\$39.63	79
Natural gas (\$/mcf)	\$4.86	\$4.89	(1)
Barrels of oil equivalent (\$/boe) ⁽²⁾	\$49.99	\$26.13	91
Downstream			

Refining throughput crude charged (bbl/d)	9,347	6,867	36
Refinery utilization (%)	98%	72%	36
Margins (%)	(8%)	7%	(214)

(1) Cash flow and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow is calculated before changes in non-cash working capital, pension funding and asset retirement expenditures. The most comparable measure calculated in accordance with GAAP would be cash flow from operating activities. Cash flow is reconciled with cash flow from operating activities on the Consolidated Statement of Cash Flows and in the accompanying Management's Discussion & Analysis ("MD&A"). Commonly used in the oil and gas industry, management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to internally fund future growth expenditures.

(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf: 1 bbl. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

(3) Product pricing is net of transportation costs but before realized and unrealized risk management contracts gains/losses.

Letter to Shareholders

Connacher continued to make great progress during the first quarter 2010 ("Q1 2010"). Our focus was primarily on completing construction of Algar, Connacher's second steam assisted gravity drainage ("SAGD") bitumen production project within the Great Divide oil sands region of northeastern Alberta. The project is designed to produce 30,000 bbl/d of steam, with a contemplated peak design steam/oil ratio ("SOR") of 3, which we expect to achieve once we ramp up our production levels. This would facilitate production of approximately 10,000 bbl/d of bitumen. We are pleased to report this project was completed ahead of schedule and is anticipated to be under budget, a considerable achievement. We are awaiting receipt of final billings to complete our calculations in this regard.

During the construction period, we also drilled and cased 17 SAGD horizontal well pairs which will be tied into the plant and related facilities and start to receive steam approximately mid-May 2010, once the commissioning of the facility is completed and steam production is initiated. We envisage steam will be circulated in all 34 wellbores for a period up to approximately 90 days, after which, based on our experience at Pod One and given the high quality nature of the reservoir from which production will be sourced, we anticipate starting bitumen production by August 2010. It is also our expectation that commerciality may be achieved by the fourth quarter 2010, after which time we will book production, sales and related costs, including interest on long-term debt incurred to build Algar. Prior to that time, all related costs have been or will be capitalized and represent a portion of our capital budget.

Algar encapsulates a larger scale than Pod One, primarily because it was designed to eventually facilitate the incorporation of added equipment to enable production at this location to reach 34,000 bbl/d of bitumen. In that regard, we will shortly be submitting our formal application to expand Algar to this larger scale, with construction likely to proceed in 2012 after formal approvals are received. The approval process is anticipated to take upwards of 18 months. In the interim, as we optimize production, realize an expanded revenue base and generate additional cash flow from operations, we will finalize our design plans, pace and scope of expansion. Inevitably, as is our custom, we will start the process of preordering long-lead items, while hopefully building up cash balances. We envisage using a similar model to our previous experiences at Pod One and Algar, which emphasized timeliness and efficiency of smaller scale operations. Embodied in our modular approach in what will be a brownfield expansion will be our focus on converting assets to cash flow quickly, while minimizing or, if possible, eliminating the need for substantial amounts of permanent external capital, while remaining on our path to achieving our goal of 50,000 bbl/d of bitumen production at Great Divide by 2015.

During Q1 2010, in addition to our efforts to complete Algar, we also focused on increased production stability at Pod One and dealt with some minor, but ultimately manageable, operational issues. We also commenced our program of installing additional pumping capacity to allow us to distribute steam in the most efficient manner to ramp up production while reducing SORs. SORs in the quarter averaged 3.6, including an average SOR of 3.0 in the eight SAGD well pairs that

have electric submersible pumps (“ESPs”) and an average of 4.2 in the nine SAGD well pairs without pumps. Subsequent to the reporting period, we installed the first ever high temperature ESP in one of our wells at Pod One. This new generation of ESPs will allow us to produce at lower pressure without having to reduce temperatures and should lead to improved productivity and lower SORs. We expect SORs to be lowered as we expand the introduction of these and other types of pumps to our operation. We also anticipate being able to optimize the amounts of steam injected into individual SAGD well pairs with the aid of the interpreted results of time-lapsed three dimensional seismic, which was shot in Q1 2010.

We conducted an extensive and successful 68 core hole drilling program during Q1 2010, largely on previously undrilled portions of our main lease block at Great Divide. This program also saw 13 gross (6.5 net) core holes drilled on our 50 percent-owned Halfway Creek property, situated close to Fort McMurray, Alberta. We are pleased with the results obtained and have commissioned our independent evaluators, GLJ Petroleum Consultants Ltd. (“GLJ”), to do a mid-year update which will incorporate our Q1 2010 drilling results, both conventional and in the oil sands. We anticipate reporting the results of this update to shareholders in early July 2010.

Now that we have completed the construction of Algar, our focus will inevitably turn to production growth. Our first order of business is to finish the commissioning and steaming program at Algar, followed by commencement of this new production source for the company, which we anticipate will contribute to significant growth in total production and cash flow in both 2010 and again in 2011, as our expanded productive capacity is realized. We are also focusing on realizing the productive potential at Pod One, following the achievement of increasingly stable production rates, while overcoming minor operational challenges along the way. The introduction of new “state of the art” pumping capacity at Pod One will contribute to this realization, as will the eventual commencement of production from the two new well pairs in the heart of the producing reservoir, anticipated to occur later in 2010. We do not envisage having to drill additional wells at Pod One for some time, although we might consider wedge or infill wells at some point to optimize the benefit from our continuous steaming and to complement the positive impact we expect from our pump installation program. We are continuing to examine other technical innovations which we believe may help reduce SORs, increase short term productivity and long-term recovery rates.

In view of past experience, we anticipate a reasonably quick ramp up of bitumen production at Algar and hope to exit the year at levels to permit the booking of an annualized average of approximately 1,685 bbl/d of bitumen from our new project. This estimate is contained in our 2010 outlook as presented in the Management’s Discussion and Analysis (“MD&A”) attached hereto. With anticipated production from Pod One averaging approximately 8,500 bbl/d, we envisage total 2010 bitumen production at approximately 10,185 bbl/d of bitumen with a 2010 exit rate ranging between 16,000 and 17,000 bbl/d of bitumen. Including our forecasts of results from conventional production and from our refining operation, we envisage 2010 adjusted EBITDA (as defined in our MD&A) of \$131 million, which when combined with our cash balances and available credit at the beginning of the year, will provide sufficient funds to meet all debt servicing obligations, finance a revised modestly reduced capital budget of \$247 million and still leave the company with surplus funds and unused credit headed into 2011. It should be noted most of our capital program was front loaded into Q1 2010 and our adjusted EBITDA estimate is anticipated to increase substantially in the second half of 2010. This buoys our confidence about maintaining desirable levels of corporate liquidity.

It now appears that 2011 will be a year of consolidation and planning, but should still be characterized by significant production growth over 2010 averages, with a resultant increase in adjusted EBITDA and cash flow. This assumes, of course, that there is no unusual downward adjustment to crude oil prices in the marketplace. The increases are anticipated to occur as Algar 2011 production exceeds year end exit rates and 2010 averages. When combined with our outlook for 2011 production at Pod One, we envisage favorable quarter over quarter and year over year improvement. Our hedging program should also elevate confidence in and the realization of our financial forecasting. We are refining our financial forecasts and budgets and developing a longer term plan to be in the best position to streamline our 2012-2013 expansion at Algar with a view to being financed to the extent possible by internal sources of capital.

Recently, we have been approached by a number of parties interested in securing participation with us in either the existing assets, our planned Algar expansion or new projects, so this also remains a potential source of future funding for Connacher. These alternatives will be critically evaluated and only pursued if it is apparent our return on capital could be improved and our operational flexibility and growth profile would not be compromised. Having a 100 percent working interest contributes to a higher level of efficiency.

We anticipate our conventional operations will remain stable throughout 2010 and that our refining operations will contribute significantly improved results during the upcoming two quarters of 2010, before we again revert to asphalt inventory buildup in Q4 2010 and Q1 2011. We are fortunate in having approximately 580,000 barrels of asphalt inventory committed to purchasers at an average price approximating US\$100 per barrel and hope to effect these sales during the spring and summer months of 2010, weather permitting. We continue to see the long-term merits of our integrated strategy, especially now that heavy oil differentials have widened somewhat in a counter-seasonal fashion.

We continue to monitor new growth opportunities in our basic business of bitumen development and production. Some of these may require cooperation with new joint venturers. Others are of a scale we might be able to pursue on our own, as we plot our course beyond the efficient and timely development of our very significant reserve base at Great Divide. We also monitor growth opportunities in other aspects of our business with a view to maintaining an appropriate balance in our system. In this manner, we can avoid leakages to third parties through either the purchase of natural gas or of heavy oil for our refinery. Purchases of these commodities not offset by our own production raises the level of associated risk. However, given the current low relative selling price for natural gas and a heavy oil differential much tighter than long-term averages, we are not exceedingly uncomfortable being temporarily "short" natural gas production and heavy oil refining capacity, as we bring on new bitumen production from Algar. As the capital markets give greater recognition to the significant underlying value of our reserve base, we may in future be able to capitalize on rebalancing opportunities in a cost effective manner. Until then, we are focused, committed to our growth program and continue to emphasize cost efficiency and excellence in our operations.

Our goal is also to have a stable, appropriate and strong balance sheet to finance our growth objectives. We have now significantly derisked Algar and are into the process of growing into our balance sheet, which should provide comfort for our equity holders and the owners of our debt. Very few, if any, other companies in the Western Canadian oil business are positioned to imminently deliver the kind of organic production growth that Connacher now has in its possession. We encourage our shareholders to continue their commitment as we focus our efforts on the delivery of consistently improving results to you during the current year.

We are pleased to announce that in accordance with our succession plan, as developed with our Governance Committee and the Board, we have promoted Mr. Peter Sametz to the position of President. He will continue as Chief Operating Officer. In preparation for a planned relinquishment of executive responsibility in 2014, Mr. R. A. Gusella will assume the position of Chairman and Chief Executive Officer. Messrs. Gusella and Sametz will continue to work together in a constructive manner to advance the interests of the company and its shareholders.

We are also pleased to announce that Mrs. Brenda G. Hughes, C.A. has joined the company as Assistant Corporate Secretary. Brenda will focus her initial efforts on regulatory and governance compliance matters.

Forward Looking Information

This press release contains forward-looking information including but not limited to the anticipated timing for completion of commissioning, steam circulation, rampup and determination of commerciality of Algar, expectations of future production growth at Pod One and Algar during 2010, 2011 and by 2015, anticipated increases in reserves and resources as a result of extensive core hole drilling during 2010, planned capital expenditures for 2010 (including anticipated sources of funding for capital expenditures and current financial obligations), planned timing of submission of the formal application to further expand Great Divide bitumen production with construction of a brownfield expansion to increase productive capacity at Algar by 34,000 barrels per day (resulting in total plant design capacity at Algar of 44,000 barrels per day) and anticipated timing of receipt of required regulatory approvals, anticipated improvements

in operating and financial results in 2010 and 2011 as a result of increased production, improved operating efficiencies and commodity price and narrow heavy oil differentials, anticipated reductions in SORs and operating costs as a result of the installation of ESPs in all Pod One wells to improve productivity, estimated full year 2010 adjusted EBITDA of \$131 million, forecast netbacks and refinery margins for 2010, expectations regarding the fulfillment of forward sales contracts of asphalt in 2010 and anticipated improvements in refinery margins, discussions regarding possible business relationships to accelerate the development of the company's oil sands resources and future plans for strategically expanding natural gas productive capacity. Additional forward looking information including forecast 2010 financial outlook is contained in the Management's Discussion and Analysis ("MD&A") attached to this press release. See "Forward Looking Information" in the MD&A.

Forward looking information is based on management's expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities and future economic conditions. Forward looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates, the uncertainty of geological interpretations, the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), the risk of commodity price and foreign exchange rate fluctuations, risks associated with the impact of general economic conditions, risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the operation and continued expansion of the Great Divide oil sands project. The 2010 financial outlook contained in the MD&A is based on certain assumptions regarding revenue (including production levels, refinery throughput, commodity prices, differentials, quality of bitumen produced, foreign exchange rates and transportation costs), operating and other costs, royalties and general and administrative costs which are detailed in the notes to the tables contained in the MD&A. Actual netbacks, refinery margins and adjusted EBITDA realized by Connacher in 2010 could differ materially from the estimates contained in the 2010 financial outlook. Material risks and uncertainties that may impact achievement of the 2010 netbacks, refinery margins and adjusted EBITDA are described in the MD&A. Additional risks and uncertainties affecting Connacher and its business and affairs are described in further detail in Connacher's Annual Information Form for the year ended December 31, 2009, which is available at www.sedar.com. Readers are cautioned that netbacks, refinery margins, adjusted EBITDA and cash flow are non-GAAP measures. These measures are discussed in detail and reconciled to net earnings in the MD&A attached hereto. Although Connacher believes that the expectations in such forward looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward looking information included in this press release is expressly qualified in its entirety by this cautionary statement. The forward looking information included herein is made as of May 11, 2010 and Connacher assumes no obligation to update or revise any forward looking information to reflect new events or circumstances, except as required by law.

For further information, contact:

Richard A. Gusella
Chairman and Chief Executive Officer

OR

Grant D. Ukrainetz
Vice President, Corporate Development

Phone: (403) 538-6201 Fax: (403) 538-6225
inquiries@connacheroil.com Website: www.connacheroil.com

MANAGEMENT'S DISCUSSION AND ANALYSIS

Connacher's focus during the first quarter 2010 ("Q1 2010") was on construction of Algar, its second steam assisted gravity drainage ("SAGD") oil sands project. We achieved another milestone with the completion of the construction of Algar in the Great Divide area ahead of schedule and is anticipated to be under budget. Commissioning of the Algar plant commenced on April 19, 2010 and is anticipated to be completed in mid-May 2010, after which commissioning of the project's three SAGD well pads and commencement of initial steaming of the associated 17 SAGD well pairs will begin. First bitumen production from Algar is anticipated in August 2010. The company's bitumen operations at Great Divide currently consist of its first producing SAGD oil sands project, Pod One and Algar. Pod One has a rated steam generation capacity of 27,000 bbl/d and at its peak target steam: oil ratio ("SOR") of 2.7, would facilitate 10,000 bbl/d of bitumen production. Algar has a rated steam generation capacity of 30,000 bbl/d and at its projected peak target SOR of 3.0, could also facilitate 10,000 bbl/d of bitumen production.

The company also conducted an extensive core hole drilling program at Great Divide and on its 50 percent owned Halfway Creek property during Q1 2010, while also continuing to develop and produce its conventional reserve base and to operate its Montana refinery, through the company's wholly-owned subsidiary, Montana Refining Company, Inc. ("MRCI") and maintain a significant equity stake in Petroliera Petroleum Limited.

This Management's Discussion and Analysis (MD&A") is dated as of May 11, 2010 and should be read in conjunction with Connacher's interim consolidated financial statements for the three months ended March 31, 2010 ("Q1 2010") and 2009 ("Q1 2009"), and the MD&A and audited consolidated financial statements for the years ended December 31, 2009 and 2008. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. MD&A provides management's view of the financial condition of the company and the results of its operations for the reporting periods. Additional information relating to Connacher, including Connacher's Annual Information Form ("AIF"), is on SEDAR at www.sedar.com.

NON-GAAP MEASUREMENTS

The MD&A contains terms commonly used in the oil and gas industry, such as cash flow, cash flow per share, netback, bitumen netback, conventional netback, refinery netback and margins, corporate netback and adjusted earnings before interest, taxes, depreciation and amortization ("adjusted EBITDA"). These terms are not defined by GAAP and should not be considered an alternative to, or more meaningful than, cash provided by operating activities or net earnings as determined in accordance with GAAP as an indicator of Connacher's performance. Management believes that in addition to net earnings, cash flow, netbacks and adjusted EBITDA are useful financial measurements which assist in demonstrating the company's ability to fund capital expenditures necessary for future growth or to repay debt. Connacher's determination of cash flow, netbacks and adjusted EBITDA may not be comparable to that reported by other companies. All references to cash flow throughout this report are based on cash flow from operating activities before changes in non-cash working capital, pension funding and asset retirement expenditures. The company calculates cash flow per share by dividing cash flow by the weighted average number of common shares outstanding. Netbacks, including by product, are calculated by deducting the related diluent, transportation, field operating costs and royalties from revenues. Adjusted EBITDA is calculated as net earnings before finance charges, taxes, depreciation, amortization and accretion, stock based compensation, foreign exchange gains/losses, unrealized gains/losses on risk management contracts, interest/other income, equity earnings/losses and dilution gains/losses. Cash flow is reconciled to cash flow from operating activities and netbacks and adjusted EBITDA are reconciled to net earnings. Additionally, future anticipated 2010 netbacks and 2010 adjusted EBITDA are reconciled to actual results in the MD&A on a quarterly basis.

FORWARD-LOOKING INFORMATION

This report, including the Letter to Shareholders and the updated 2010 financial outlook contained in the MD&A, contains forward-looking information including but not limited to anticipated future operating and financial results, forecast netbacks, future corporate general and administration expenses, forecast adjusted EBITDA, future profitability, expectations of future production, anticipated sales volumes, anticipated capital expenditures, further anticipated reductions in operating costs as a result of continued operational optimization, development of additional oil sands resources (including Algar and the timeline for commissioning and steam circulation prior to commercial production at Algar, and the potential timing of achieving commerciality at Algar), expansion of current conventional oil and gas and oil sands operations including the expected timing of the formal application in respect of the expansion at Great Divide, anticipated sources of funding for capital expenditures and current financial obligations, future development and exploration activities, future heavy oil differentials, expectations regarding the fulfillment of forward sales contracts of asphalt in 2010 and anticipated improvements in refining margins, planned installation of ESPs at Pod One, potential future steam generation levels at Pod One and Algar, anticipated use of the Revolving Credit Facility, utilization of alternative financial derivative strategies to protect the company's cash flow and potential corporate acquisitions or business combinations and joint venture or participation arrangements. Forward-looking information is based on management's expectations regarding future growth, results of operations, production, future commodity prices and foreign exchange rates, future capital and other expenditures (including the amount, nature and sources of funding thereof), plans

for and results of drilling activity, environmental matters, business prospects and opportunities, future economic conditions and the plans and expected impacts of adopting International Financial Reporting Standards. Forward-looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks; the risk of commodity price and foreign exchange rate fluctuations; risks associated with the impact of general economic conditions; and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Great Divide Oil Sands Project. In addition, the recent financial crisis has resulted in economic uncertainty and illiquidity in credit and capital markets which increases the risk that actual results will vary from forward-looking expectations in this report and these variations may be material. The 2010 financial outlook contained in the MD&A is based on certain assumptions regarding revenue (including production levels, refinery throughput, commodity prices, differentials, quality of bitumen produced, foreign exchange rates and transportation costs), operating and other costs, royalties and general and administrative costs which are detailed in the notes to the tables contained in the MD&A. Actual netbacks and adjusted EBITDA realized by Connacher in 2010 could differ materially from the estimates contained in the 2010 financial outlook. Material risks and uncertainties that may impact achievement of the 2010 netbacks and adjusted EBITDA are described in this MD&A. These and other risks and uncertainties are described in further detail in Connacher's Annual Information Form for the year ended December 31, 2010 ("AIF"), which is available at www.sedar.com.

Although Connacher believes that the expectations in such forward-looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward-looking information included in this report is expressly qualified in its entirety by this cautionary statement. The forward-looking information included in this report is made as of May 11, 2010 and Connacher assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law.

Throughout the MD&A, per barrel of oil equivalent (boe) amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil (6:1). The conversion is based on an energy equivalency conversion method primarily applicable to the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

MARKETING – UPSTREAM

Diluted bitumen ("dilbit"), crude oil and natural gas are generally sold on month-to-month sales contracts negotiated with major Canadian or U.S. marketers, refiners, regional upgraders or other end users, at either spot reference prices or at prices subject to commodity contracts based on WTI market prices for crude oil and AECO market prices for natural gas. In this regard, Connacher has entered into various contracts for the supply of dilbit to a variety of heavy oil purchasers in central and northern Alberta. In order to secure preferred diluent supplies, Connacher has also entered into several short-term diluent purchase contracts. As a means of managing the risk of commodity price volatility, Connacher enters into risk management commodity sales contracts from time to time.

In Q1 2010, Connacher fulfilled a variety of short-term supply contracts for the sale of dilbit to a variety of purchasers in central and northern Alberta. Our selling prices received for dilbit sales were also influenced by the following WTI crude oil price hedging sales contracts:

- Calendar year 2010 – 2,500 bbl/d at WTI US\$78.00/bbl; and
- February 1, 2010 – April 30, 2010 – 2,500 bbl/d at WTI US\$79.02/bbl.

In addition, the following costless collar contract was outstanding as at March 31, 2010:

- May 1, 2010 – December 31, 2010 – 2,500 bbl/d at a minimum of WTI US\$75.00/bbl and a maximum of WTI US\$95.00/bbl.

In Q1 2010, the realized losses on these contracts totaled \$172,000 (gain of \$406,000 in Q1 2009). These contracts were accounted for as a financial derivative and an unrealized loss of \$778,000 (\$8.3 million in Q1 2009) representing the change in the fair value of these contracts as at March 31, 2010 was also recorded.

Subsequent to March 31, 2010, the company entered into the following additional WTI crude oil price hedging sales contracts:

- January 1, 2011 – March 31, 2011 – 1,000 bbl/d at WTI US\$86.10/bbl;
- January 1, 2011 – March 31, 2011 – 1,000 bbl/d at WTI US\$88.10/bbl; and
- January 1, 2011 – March 31, 2011 – 2,000 bbl/d at a minimum of WTI US\$80.00/bbl and a maximum of WTI US\$100.25/bbl.

MARKETING – DOWNSTREAM

Sales of refined petroleum products are generally made on monthly sales contracts negotiated with wholesalers, retailers and large end-users for gasoline, jet fuel and diesel and with construction contractors and road builders for asphalt. Occasionally, sales contracts are for periods in excess of one month. Currently, MRCI has contracts to sell approximately 580,000 barrels of asphalt throughout 2010 at an average selling price of approximately US\$100 /bbl.

In March 2010, Connacher entered in the following risk management sales contract to hedge its gasoline revenue:

- April 1, 2010 – September 30, 2010 – 2,000 bbl/d at the calendar month average WTI price in US\$/bbl plus US\$9.00 /bbl.

An unrealized loss, representing the change in the fair value of the contract as at March 31, 2010, of \$614,000, was recorded in Q1 2010.

PRICING

General economic conditions and international and local supplies, together with many other uncontrollable variables, influence the price for WTI light gravity crude oil. Weather, domestic supplies, restricted continental markets and other variables influence the market price for natural gas.

Our revenues, cash flow and earnings are significantly influenced by the volatility of crude oil and natural gas prices. In Q1 2010, WTI crude oil traded between US\$71.19/bbl and US\$83.76/bbl (Q1 2009 – between US\$33.98/bbl and US\$54.34/bbl) and on an average basis was 83 percent higher in Q1 2010 (US\$78.84/bbl) than in Q1 2009 (US\$43.08). In Q1 2010, AECO natural gas traded in a range of \$3.60/Mcf to \$5.95/Mcf (Q1 2009 – \$3.69/Mcf to \$6.61/Mcf), averaging \$4.92/Mcf in Q1 2010 compared to \$5.63/Mcf in Q1 2009, a decrease of 13 percent. (Source: Bloomberg)

Connacher's crude oil and bitumen production slate is heavier gravity than the referenced WTI. Consequently, the market price realized by the company is lower than WTI. This difference is commonly referred to as the "heavy oil differential".

Before risk management contracts gains and losses and after deducting applicable diluent and transportation costs, Connacher realized the following commodity selling prices during Q1:

Upstream average realized selling price	2010	2009	% Change
Bitumen – \$/bbl	\$ 51.98	\$ 22.45	132
Crude oil – \$/bbl	\$ 71.08	\$ 39.63	79
Natural gas – \$/Mcf	\$ 4.86	\$ 4.89	-

Downstream average realized selling price (US\$/bbl)	2010	2009	% Change
Gasoline	\$ 85.07	\$ 45.67	86
Diesel	\$ 87.63	\$ 59.08	48
Asphalt	\$ 53.33	\$ 43.16	24
Jet fuel	\$ 94.05	\$ 70.75	33

Higher refined petroleum product prices in Q1 2010 were consistent with higher average WTI prices. Selling prices of refined petroleum products are also influenced by general economic conditions and local and international supply and demand factors. Realized selling prices for MRCI's refined products in Q1 2010 and Q1 2009 are noted above.

FINANCIAL AND OPERATING REVIEW

UPSTREAM NETBACKS (\$'000)

For the three months ended March 31, 2010	Oil Sands	Crude Oil	Natural Gas	Total
Gross revenues ⁽¹⁾	\$ 55,173	\$ 5,999	\$ 4,230	\$ 65,402
Diluent purchased ⁽²⁾	(19,517)	-	-	(19,517)
Transportation costs	(3,209)	(5)	-	(3,214)
Production revenue	32,447	5,994	4,230	42,671
Royalties	(1,385)	(1,569)	(95)	(3,049)
Operating costs	(12,041)	(1,113)	(1,759)	(14,913)
Netback ⁽³⁾	\$ 19,021	\$ 3,312	\$ 2,376	\$ 24,709

For the three months ended March 31, 2009	Oil Sands	Crude Oil	Natural Gas	Total
Gross revenues ⁽¹⁾	\$ 28,669	\$ 4,278	\$ 5,641	\$ 38,588
Diluent purchased ⁽²⁾	(13,367)	-	-	(13,367)
Transportation costs	(2,837)	(70)	-	(2,907)
Production revenue	12,465	4,208	5,641	22,314
Royalties	(129)	(1,062)	(1,389)	(2,580)
Operating costs	(11,331)	(1,302)	(2,506)	(15,139)
Netback ⁽³⁾	\$ 1,005	\$ 1,844	\$ 1,746	\$ 4,595

(1) Bitumen produced at Pod One is mixed with purchased diluent and sold as "dilbit". Diluent is a light hydrocarbon that improves the marketing and transportation quality of bitumen. In the above tables, gross revenues represent sales of dilbit, crude oil and natural gas. In the financial statements Upstream Revenues represent sales of dilbit, crude oil and natural gas, net of royalties and Upstream Operating Costs include the cost of purchased diluent.

(2) Diluent volumes purchased and blended into dilbit sales have been deducted in calculating production revenue and production volumes sold. Diluent purchased includes purchases from our downstream segment. Although, they have been included in these upstream netback calculations, these intercompany transactions have been eliminated in our consolidated financial statements.

(3) Netbacks are calculated before adding/deducting risk management contracts gains/losses. Netbacks on a per-unit basis are calculated by dividing netbacks by production volumes. Netbacks do not have a standardized meaning prescribed by GAAP and, therefore, may not be comparable to similar measures used by other companies. This non-GAAP measurement is widely used in the oil and gas industry as a supplemental measure of the company's efficiency and its ability to fund future growth through capital expenditures. Upstream Netbacks are reconciled to net earnings below.

UPSTREAM SALES AND PRODUCTION VOLUMES

For the three months ended March 31	2010	2009	% Change
Dilbit sales – bbl/d	9,249	8,531	8
Diluent purchased – bbl/d	(2,313)	(2,361)	(2)
Bitumen produced and sold – bbl/d	6,936	6,170	12
Crude oil produced and sold – bbl/d	937	1,180	(21)
Natural gas produced and sold – Mcf/d	9,662	12,828	(25)
Total – boe/d	9,483	9,488	-

UPSTREAM NETBACKS PER UNIT OF PRODUCTION

For the three months ended March 31, 2010	Bitumen (\$ per bbl)	Crude Oil (\$ per bbl)	Natural Gas (\$ per Mcf)	Total (\$ per boe)
Production revenue	\$ 51.98	\$ 71.08	\$ 4.86	\$ 49.99
Royalties	(2.22)	(18.60)	(0.11)	(3.57)
Operating costs	(19.29)	(13.20)	(2.02)	(17.47)
Netback	\$ 30.47	\$ 39.28	\$ 2.73	\$ 28.95

For the three months ended March 31, 2009	Bitumen (\$ per bbl)	Crude Oil (\$ per bbl)	Natural Gas (\$ per Mcf)	Total (\$ per boe)
Production revenue	\$ 22.45	\$ 39.63	\$ 4.89	\$ 26.13
Royalties	(0.23)	(10.00)	(1.20)	(3.02)
Operating costs	(20.41)	(12.26)	(2.17)	(17.73)
Netback	\$ 1.81	\$ 17.37	\$ 1.52	\$ 5.38

Q1 2010 gross upstream production revenues were \$42.7 million, compared to \$22.3 million in Q1 2009. This increase was primarily attributable to higher bitumen and crude oil pricing, which was slightly offset by lower natural gas production and sales volumes in Q1 2010. Lower natural gas production and sales volumes in Q1 2010 reflect the impact of reduced development capital spending in 2009 because of low selling prices and natural production declines.

Although total Q1 2010 boe production and sales volumes were consistent with Q1 2009, bitumen and crude oil selling prices were substantially higher in Q1 2010. WTI averaged US\$78.84/bbl in Q1 2010 compared to US\$43.08/bbl in Q1 2009, an 83 percent increase; natural gas selling prices were relatively unchanged. Consequently, gross upstream production revenues were up 91 percent to \$42.7 million in Q1 2010 compared to Q1 2009. Our Q1 2010 upstream results were modestly impacted by realized and unrealized risk management contract losses of \$172,000 and \$778,000, respectively, as compared to a realized gain of \$406,000 and unrealized loss of \$8.3 million in Q1 2009. Details of these contracts are addressed in "Marketing-Upstream", herein.

In Q1 2010, upstream diluent purchases of \$19.5 million (Q1 2009 – \$13.4 million) were required for our oil sands operations. These purchases include \$4.0 million of diluent purchased at market prices directly from our subsidiary, MRCl, in Q1 2010 (Q1 2009 – \$470,000). Although these intercompany costs were included in our netback calculations above to accurately present bitumen netbacks, for consolidated financial statement presentation purposes, these intercompany purchases were eliminated.

Bitumen produced at Pod One was mixed with purchased diluent and sold as "dilbit." Diluent is a light liquid hydrocarbon used in our oil sands treating processes and enabled the efficient marketing and transportation of bitumen. Diluent purchased represented approximately 25 percent of the dilbit barrel sold in Q1 2010, with bitumen the remaining 75 percent; in Q1 2009, these splits were 28 percent and 72 percent, respectively. The price of diluent closely tracked WTI crude oil prices. Consequently, diluent costs were higher in Q1 2010 relative to the comparative Q1 2009 periods, while comparative volumes changed only slightly.

Royalties represent charges against production or revenue by governments and landowners. From quarter to quarter, royalties can change based on changes in the product mix, the components of which are subject to different royalty rates. Additionally, royalty rates are applied on a sliding scale to commodity prices. Royalties in Q1 2010 were \$3.0 million compared to \$2.6 million in Q1 2009. The increase in overall royalties' costs in Q1 2010 was primarily due to higher oil prices. This was reflected in higher per unit royalty costs for bitumen (\$2.22/bbl compared to \$0.23/bbl in Q1 2009) and crude oil (\$18.60/bbl compared to \$10.00/bbl in Q1 2009). The reduction in the Q1 2010 per unit royalty cost for natural gas compared to Q1 2009 reflected Alberta gas cost allowance recoveries associated with lower natural gas prices.

Operating costs in Q1 2010 of \$14.9 million were one percent lower than the \$15.1 million in Q1 2009. Bitumen operating costs were \$12.0 million in Q1 2010 (\$19.29/bbl of bitumen) compared to \$11.3 million (\$20.41/bbl of bitumen) in Q1 2009, an overall increase of 6 percent, reflecting higher bitumen production in Q1 2010 compared to Q1 2009. Natural gas costs (primarily variable in nature) comprised \$4.5 million, or 38 percent, of Q1 2010 oil sands operating costs (Q1 2009 – \$3.9 million, or 34 percent); and personnel, power, chemicals, facility, workover and evaporator waste disposal costs (primarily fixed in nature) comprised \$7.5 million, or 62 percent (Q1 2009 – \$ 7.4 million, or 66 percent). At our Pod One facility, in Q1 2010 we used 10,025 Mcf/d of natural gas at an average cost of \$5.00/Mcf (Q1 2009 – 8.9 MMcf/d at \$4.91/Mcf). This equates to 1.44 Mcf of natural gas consumed to produce 1 bbl of bitumen in each of Q1 2010 and Q1 2009, or a SOR of 3.6 in both quarters. In Q1 2010, an average SOR of 3.0 in the eight SAGD well pairs that had downhole pumps was offset by an average SOR of 4.2 in the nine SAGD well pairs without downhole pumps. The ability to continue lowering SORs in Pod One is anticipated with the installation of nine additional downhole pumps in the second and third quarters of 2010 and through improved anticipated distribution of steam injected into our bitumen (or oil sands) reservoir based on time lapsed 3D seismic results expected in Q2 2010. Reducing our SORs will enable us to "free up" steam to facilitate the steaming of, and eventual production from, our two newest SAGD well pairs, which were drilled in Q1 2010 and are well structured in the Pod One reservoir.

Conventional crude oil operating costs were reduced slightly on an absolute basis (\$1.1 million in Q1 2010 compared to \$1.3 million in Q1 2009) but were slightly higher on a per unit basis (\$13.20 per bbl in Q1 2010 compared to \$12.26 per bbl in Q1 2009), primarily due to lower production volumes in Q1 2010 (937 bbl/d in Q1 2010 compared to 1,180 bbl/d in Q1 2009). The majority of this crude oil production is from the Battrum area of south west Saskatchewan, a late-stage water flood project.

Natural gas operating costs of \$1.8 million (\$2.02/Mcf) were lower in Q1 2010 than in Q1 2009 when they were \$2.5 million (\$2.17/Mcf), due to improved operating efficiencies, lower well workover costs and lower natural gas production in Q1 2010.

On a per unit basis, total upstream operating costs of \$17.47 per boe in Q1 2010 were lower compared to \$17.73 per boe in Q1 2009, modestly reflecting the benefit of our optimization strategies.

Transportation costs represent costs to transport dilbit, crude oil and natural gas to customers. Transportation costs, primarily for trucking dilbit, were slightly higher in Q1 2010 than Q1 2009 (\$3.2 million compared to \$2.9 million). These costs are reported as an expense in our consolidated statement of operations but have been deducted in calculating reported product selling prices. The overall increase of 11 percent in Q1 2010 as compared to Q1 2009 was due to the increase in dilbit sales.

Netbacks are a widely used industry measure of a company's efficiency and its ability to internally fund its growth. Compared to Q1 2009, significantly higher upstream commodity selling prices in Q1 2010 resulted in substantially improved netbacks. Netbacks were \$24.7 million in Q1 2010 (\$28.95 per boe) compared to \$4.6 million (\$5.38 per boe) in Q1 2009. This was primarily because our realized bitumen price was 132 percent higher and our realized crude oil selling price was 79 percent higher. Consequently, netbacks per boe were 438 percent higher in Q1 2010 compared to Q1 2009 levels.

RECONCILIATION OF UPSTREAM NETBACK TO NET EARNINGS

For the three months ended March 31 (\$000, except per unit amounts)	2010		2009	
	Total	Per boe	Total	Per boe
Upstream netback, as above	\$ 24,709	\$ 28.95	\$ 4,595	\$ 5.38
Interest and other income	71	0.08	928	1.09
Downstream margin – net	(4,700)	(5.51)	2,432	2.85
Loss on risk management contracts	(1,564)	(1.83)	(7,861)	(9.21)
General and administrative	(5,552)	(6.51)	(4,474)	(5.24)
Stock-based compensation	(1,891)	(2.22)	(1,270)	(1.49)
Finance charges	(12,729)	(14.91)	(9,160)	(10.73)
Foreign exchange gain (loss)	23,943	28.05	(27,866)	(32.63)
Depletion, depreciation and accretion	(18,617)	(21.81)	(16,449)	(19.26)
Income taxes	2,524	2.96	11,998	14.05
Equity interest in Petrolifera (loss) earnings	(648)	(0.76)	283	0.33
Net earnings (loss)	\$ 5,546	\$ 6.49	\$ (46,844)	\$ 54.86

DOWNSTREAM REVENUES AND MARGINS

Connacher's 9,500 bbl/d heavy oil refinery, located in Great Falls, Montana (the "Refinery"), is a strategic fit with our oil sands development. It is the closest U.S. refinery to Alberta's oil sands and processes Canadian heavy crude oil, similar to Great Divide dilbit, into a range of higher value refined petroleum products, including regular and premium gasoline, jet fuel, diesel and asphalt. Accordingly, the Refinery provides a notional hedge for our bitumen revenues by recovering a portion of the heavy oil differential under normal operating conditions.

The Refinery is a complex operation and includes reforming, isomerization and alkylation processes for formulation of gasoline blends, hydro-treating for sulphur removal and fluid catalytic cracking for conversion of heavy gas oils to gasoline and distillate products. It also is a major supplier of paving grade asphalt, polymer modified grades and asphalt emulsions for road construction. The Refinery delivers products in Montana and neighboring regions by truck and rail transport.

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

The Refinery operates in a "niche" market that incorporates Great Falls and surrounding area, Western Montana, Northern Idaho, Eastern Washington and Southern Alberta. While the "niche" market provides some insulation from a very challenging North American refining

market, MRCI margins were impacted by narrower heavy oil differentials, reduced product demand and lower product prices because of competing gasoline imports.

Downstream revenues of \$61.6 million in Q1 2010 were 86 percent higher than \$33.2 million of refined products sold in Q1 2009. This was attributable to increased sales volumes and higher average refined product selling prices at \$81.09 /bbl in Q1 2010, compared to \$62.54 in Q1 2009. Increased refining volumes in Q1 2010 were due to the improved stability of refining operations subsequent to the completion of the ultra low sulphur diesel ("ULSD") project, which curtailed production and sales in the comparative 2009 period. Notwithstanding higher refined product prices, margins in Q1 2010 were lower than in Q1 2009 primarily due to the influence on costs of sales of higher crude oil input costs. Improved selling margins are anticipated with the commencement of the asphalt selling season in Q2 of 2010. Currently, MRCI has contracts to sell approximately 580,000 barrels of asphalt throughout 2010 at an average selling price of approximately US\$ 100 /bbl.

Downstream revenues and refining margins (in the table below) include the benefit of diluent sales revenue of \$4.0 million in Q1 2010 (\$470,000 – Q1 2009) sold to our oil sands operation, which were transacted at prevailing fair market prices. These transactions were eliminated on consolidation for financial statement presentation purposes.

General economic conditions affect refined product demand and pricing. We anticipate they will continue to influence our downstream financial results in future. To mitigate some of the risk of reduced gasoline selling prices and margins, the company entered into a risk management sales contract to sell 2,000 bbl/d of gasoline at the calendar month average WTI price in US\$/bbl plus US\$9.00/bbl for the period of April 1, 2010 to September 30, 2010.

The quarterly operating results of our Refinery are summarized below:

REFINERY THROUGHPUT

	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Mar 31 2010
Crude charged – bbl/d ⁽¹⁾	6,867	9,145	7,076	8,188	9,347
Refinery production – bbl/d ⁽²⁾	7,946	10,438	8,131	8,674	10,814
Sales of produced refined products – bbl/d	5,290	9,222	10,596	8,841	8,267
Sales of refined products (includes purchased products) – bbl/d ⁽³⁾	5,890	9,451	11,697	9,646	8,439
Refinery utilization ⁽⁴⁾	72%	96%	75%	86%	98%

(1) Crude charged represents the barrels per day of crude oil processed at the Refinery.

(2) Refinery production represents the barrels per day of refined products yielded from processing crude and other refinery feedstock.

(3) Includes refined products purchased for resale.

(4) Represents crude charged divided by total crude capacity of the Refinery.

FEEDSTOCKS

	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Mar 31 2010
Sour crude oil	91%	91%	91%	97%	87%
Other feedstocks & blends	9%	9%	9%	3%	13%
Total	100%	100%	100%	100%	100%

REVENUES AND MARGINS (\$000)

	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Mar 31 2010
Refining sales revenue	\$ 33,152	\$ 69,094	\$ 92,714	\$ 63,440	\$ 61,589
Refining – crude oil and operating costs	30,720	65,611	85,015	67,491	66,289
Refining margin	\$ 2,432	\$ 3,483	\$ 7,699	\$ (4,051)	\$ (4,700)
Refining margin (%)	7%	5%	8%	(7%)	(8%)

REVENUES AND MARGINS PER BARREL OF REFINED PRODUCT SOLD

	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Mar 31 2010
Refining sales revenue	\$ 62.54	\$ 80.34	\$ 86.16	\$ 71.73	\$ 81.09
Refining – crude oil and operating costs	57.95	76.29	79.00	76.36	87.28
Refining margin	\$ 4.59	\$ 4.05	\$ 7.16	\$ (4.63)	\$ (6.19)

SALES OF REFINED PRODUCTS (VOLUME %)

	Mar 31 2009	June 30 2009	Sept 30 2009	Dec 31 2009	Mar 31 2010
Gasoline	58%	48%	36%	39%	51%
Diesel fuels	22%	11%	10%	10%	20%
Jet fuels	6%	6%	6%	4%	8%
Asphalt	11%	31%	46%	45%	17%
Other	3%	4%	2%	2%	4%
Total	100%	100%	100%	100%	100%

INTEREST AND OTHER INCOME

In Q1 2010, the company earned interest and other income of \$71,000 (Q1 2009 – \$928,000), primarily from investing surplus funds in secure short-term investments. A portion of the interest earned was recognized as income and a portion (in respect of cash balances on hand from pre-funding oil sands projects under development) was credited to capitalized costs. Interest and other income in Q1 2009 included a gain of \$475,000 on the repurchase of Second Senior Lien Notes. No similar repurchases were made in Q1 2010.

GENERAL AND ADMINISTRATIVE EXPENSES

In Q1 2010, general and administrative (“G&A”) expenses were \$5.6 million, compared to \$4.5 million in Q1 2009, an increase of 24 percent, primarily reflecting increased staffing to support the operation of Pod One and Algar. G&A of \$2.1 million was also capitalized in Q1 2010 (Q1 2009 – \$1.5 million).

FINANCE CHARGES

Finance charges include interest expense relating to the Convertible Debentures, standby fees associated with the company’s Revolving Credit Facility, fees on letters of credit issued and a portion of the First and Second Lien Senior Notes interest not attributable to major development/capital projects. Finance charges also include non-cash accretion charges with respect to the Convertible Debentures and a portion of the First and Second Lien Senior Notes. The company capitalizes interest on a portion of its long-term debt raised to finance oil sands projects.

In Q1 2010, finance charges expensed were \$12.7 million, which was \$3.6 million higher than in Q1 2009, primarily as a result of higher debt levels since issuing the First Lien Senior Notes in mid-June 2009. In Q1 2010, Connacher capitalized interest costs of \$12.8 million (Q1 2009 – \$13.3 million) in respect of oil sands activities.

STOCK BASED COMPENSATION

The company recorded non-cash stock-based compensation charges in the respective periods as follows:

Three months ended March 31 (\$000)	2010	2009
Charged to expense	\$ 1,891	\$ 1,270
Capitalized to property and equipment	652	393
	\$ 2,543	\$ 1,663

The increase from the prior period is due to a higher fair market value for options granted during Q1 2010.

FOREIGN EXCHANGE GAINS AND LOSSES

In Q1 2010, the value of the Canadian dollar strengthened relative to the U.S. dollar. This had a significant impact on Connacher upon translating its U.S. dollar denominated long-term debt and U.S. dollar cash balances into Canadian dollars for financial reporting purposes.

In Q1 2010, Connacher had unrealized foreign exchange translation gains of \$23.0 million (Q1 2009 – loss of \$27.9 million). Connacher also realized foreign exchange gains of \$935,000 in Q1 2010 (Q1 2009 – \$Nil) upon the settlement of U.S. dollar denominated transactions.

DEPLETION, DEPRECIATION AND ACCRETION (“DD&A”)

Depletion expense is calculated using the unit-of-production method based on total estimated proved reserves. Downstream refining properties and other assets are depreciated over their estimated useful lives. DD&A in Q1 2010 was \$18.6 million. Depletion of \$14.8 million in Q1 2010 (Q1 2009 – \$13.9 million) equated to \$17.38/boe of production in Q1 2010, compared to \$16.25/boe in Q1 2009.

Future development costs of \$1.4 billion (Q1 2009 – \$1.3 billion) were included in the depletion calculation and capital costs of \$645 million (Q1 2009 – \$338 million) related to oil sands projects currently in the pre-production stage were excluded from the depletion calculation.

Included in DD&A was MRCI refinery depreciation of \$2.5 million (Q1 2009 – \$1.8 million), depreciation of furniture, equipment and leaseholds of \$607,000 (Q1 2009 – \$231,000) and an accretion charge of \$676,000 (Q1 2009 – \$491,000) in respect of the company’s estimated asset retirement obligations (“ARO”). These ARO charges will continue in future years in order to accrete the currently booked discounted liability of \$34.5 million to the estimated total undiscounted liability of \$77 million over the remaining economic life of the company’s oil sands, crude oil and natural gas properties.

INCOME TAXES

The total income tax recovery of \$2.5 million in Q1 2010 (Q1 2009 – \$12 million) included a current income tax provision of \$206,000 (Q1 2009 – \$172,000), principally related to Canadian taxes. The future income tax recovery of \$2.7 million (Q1 2009 – \$12.2 million) reflected the change in tax pools during the quarter.

The approximate amount of total income tax pools available as at March 31, 2010 were \$1,154 million in Canada and \$62 million in the USA (December 31, 2009 – \$1,075 million in Canada and \$53 million in the USA), including non-capital losses of approximately \$390 million which expire over time to 2028 and \$34 million of net capital losses which are available to reduce taxable capital gains in future. These capital losses have no expiry and their future income tax benefit has not been recognized at March 31, 2010 and December 31, 2009 due to uncertainty of their realization.

EQUITY INTEREST IN PETROLIFERA PETROLEUM LIMITED (“PETROLIFERA”)

Connacher accounts for its equity investment in Petrolifera under the equity method of accounting. Connacher’s share of Petrolifera’s loss in Q1 2010 was approximately \$648,000 (Q1 2009 – \$283,000 earnings).

In April 2010, Petrolifera closed a public offering of 23,678,500 common shares at a price of \$0.85 per common share for gross proceeds of \$20.1 million (the “Offering”). Connacher did not subscribe for shares in the Offering and accordingly, Connacher’s equity interest in Petrolifera was reduced to 18.5 percent from 22 percent as at March 31, 2010. Given Connacher’s representation on Petrolifera’s Board of Directors and other factors, Connacher continues to equity account for this investment.

NET EARNINGS

In Q1 2010, the company reporting earnings of \$5.5 million (\$0.01 per basic and diluted shares outstanding) compared to a loss of \$46.8 million (\$0.22 per basic and diluted shares outstanding) in Q1 2009. The primary reasons for these period to period variations are noted herein.

SHARES OUTSTANDING

For the quarter ended March 31, 2010, the basic and diluted weighted average number of common shares outstanding was 427.8 million and 430.1 million respectively (Q1 2009 – 211.3 million basic and diluted). The increase from the prior year was due to the 2009 equity issuances subsequent to the end of Q1 2009.

As at May 11, 2010, the company had the following securities issued and outstanding:

- 429,102,992 common shares;
- 28,999,646 share purchase options; and
- 380,598 share units under the share awards plan.

Additionally, the company’s \$100 million of outstanding Convertible Debentures are convertible into 20,002,800 common shares of the company.

PROPERTY AND EQUIPMENT EXPENDITURES

A breakdown of the expenditures is as follows:

Three months ended March 31 (\$000)	2010	2009
Crude oil, natural gas and oil sands expenditures	\$ 117,133	\$ 60,999
Refinery expenditures	1,139	3,256
	\$ 118,272	\$ 64,255

In Q1 2010, expenditures of \$49 million were incurred on the Algar project; \$11 million was incurred at Pod One to finish drilling and completing two additional SAGD well pairs and for other facility enhancement expenditures; \$22 million was incurred in drilling 68 exploratory core holes at Great Divide, 13 (6.5 net) exploratory core holes at Halfway Creek and for seismic expenditures related to the winter 2010 exploration program; \$10 million of capital expenditures were incurred for co-generation, pipeline facilities and the Great Divide expansion project; and \$17 million was capitalized for interest and G&A costs. Additionally, \$8 million was incurred on conventional drilling (one oil well, four natural gas wells and four abandoned wells), land acquisitions, seismic, well workovers, facilities and corporate and administrative assets.

Oil sands expenditures of \$55 million were incurred in Q1 2009 to drill 23 exploratory core holes and for facilities expenditures at Algar, including capitalized interest and G&A and the drilling and completion of two SAGD well pairs at Pod One. Conventional oil and gas expenditures of \$6 million in Q1 2009 include costs of drilling, completing, equipping and working over conventional oil and gas wells, seismic expenditures and facility expenditures. In Q1 2009, the company drilled two (two net) wells, resulting in one suspended well and one well abandoned.

The majority of the Q1 2010 refinery capital expenditures were incurred for various small capital projects. The Q1 2009 refinery capital expenditures were incurred for the ultra low sulphur diesel/gasoline project.

RECENT FINANCINGS

Common Share Issuance

On June 5, 2009 Connacher issued 191,762,500 common shares from treasury at a price of \$0.90 per common share, for gross proceeds of \$173 million. The proceeds were raised for working capital to fund the company's capital expenditures, including Algar and for general corporate purposes.

At March 31, 2010, the proceeds had been utilized to fund \$160 million of capital expenditures, including oil sands capital costs and the balance remained available for working capital purposes.

First Lien Senior Secured Notes

On June 16, 2009, the company issued US\$200 million first lien five-year secured notes ("First Lien Senior Notes") at an issue price of 93.678 percent for gross proceeds of \$212 million in equivalent Canadian funds. These financing proceeds were raised for working capital and general corporate purposes, including funding a portion of the remaining expenditures associated with the construction and drilling costs of Algar.

At March 31, 2010, proceeds of \$130 million had been utilized to fund capital expenditures primarily related to Algar and the balance remained available for working capital and general corporate purposes.

Flow-Through Shares

In October 2009, to fund the company's 2010 exploration program, the company issued 23,172,500 common shares on a flow-through basis at \$1.30 per common share, for gross proceeds of \$30.1 million. At March 31, 2010, proceeds of \$29 million of the flow-through financing had been utilized for the exploration program and the balance of the proceeds was included in cash balances and will be utilized for additional qualified expenditures. The company renounced the income tax benefits of these expenditures (\$30.1 million) to the subscribing investors, effective December 31, 2009.

Revolving Credit Facilities

In November 2009, the company successfully arranged a US\$50 million Revolving Credit Facility. The two year facility is available for general corporate purposes and was provided by a syndicate of Canadian and international banks. The Revolving Credit Facility provided Connacher with additional liquidity and financial flexibility. It also facilitated the issuance of letters of credit and the conduct of hedging activities. The Revolving Credit Facility is secured by a first priority security interest in all present and after-acquired assets of Connacher, except Connacher's investment in Petrolifera and the pipeline assets of an inactive subsidiary. As arranged when Connacher issued its First Lien Senior Notes earlier in 2009, the Revolving Credit Facility ranks senior to all of Connacher's indebtedness. The Revolving Credit Facility has certain financial covenants, as is customary for this type of credit. As at March 31, 2010, Connacher was in compliance with all its debt covenants.

At March 31, 2010, \$5.7 million of letters of credit were issued in the course of normal business activities pursuant to the Revolving Credit Facility.

LIQUIDITY AND CAPITAL RESOURCES

At March 31, 2010, the company had working capital of \$127 million (December 31, 2009 – \$245 million), including \$118 million of cash (December 31, 2009 – \$257 million). As there are no capital expenditures commitments and, as all of the company's indebtedness is long-term in nature, with no principal repayment obligation until June 2012, management believes that the company presently has sufficient liquidity and financial capacity to fund its ongoing capital program and to satisfy its financial obligations.

In light of the volatility of current commodity prices and the U.S.:Canadian dollar exchange rate and their significance to the company's operating performance, management constantly assesses alternative hedging strategies to protect the company's cash flow from the risk of potentially lower crude oil and refined product pricing and adverse foreign exchange rate fluctuations. Although the company's integrated business model provides some risk mitigation, it does not provide a perfect hedge, particularly against commodity price volatility. The purpose of any hedging activity we undertake is to ensure more predictable cash flow availability to supplement cash balances. This allows us to continue to service indebtedness, complete capital projects and protect the credit capacity of Connacher's oil and gas reserves in an uncertain and volatile commodity price environment.

In Q1 2010 the company entered into WTI risk management contracts on a portion of its anticipated upstream liquids production and a portion of its anticipated refined gasoline sales. Details of the outstanding risk management contracts are provided in the Marketing – Upstream and Downstream section earlier in this MD&A.

In Q1 2010, primarily due to higher commodity prices in Q1 2010, Connacher generated cash flow of \$3.9 million (\$0.01 per basic and diluted share outstanding), \$8.6 million higher than in Q1 2009.

Cash flow and cash flow per share do not have standardized meanings prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Cash flow includes all cash flow from operating activities and is calculated before changes in non-cash working capital, pension funding and asset retirement expenditures. The most comparable measure calculated in accordance with GAAP is cash flow from operating activities. Cash flow from operating activities is reconciled with cash flow for three months ended March 31, 2010 and 2009 as follows:

(\$000)	2010	2009
Cash flow	\$ 3,948	\$ (4,692)
Non-cash working capital changes	(11,879)	(24,304)
Asset retirement expenditures	(368)	(104)
Cash flow from operating activities	\$ (8,299)	\$ (29,100)

Cash flow per share is calculated by dividing cash flow by the calculated weighted average number of shares outstanding. Management uses this non-GAAP measurement (which is a common industry parameter) for its own performance measure and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund future growth expenditures.

Connacher's objectives in managing its cash, debt and equity and its future capital requirements are to safeguard its ability to meet its financial obligations, to maintain a flexible capital structure that allows multiple financing options when a financing need arises and to optimize its use of short-term and long-term debt and equity at an appropriate level of risk.

The company manages its capital structure and follows a financial strategy that considers economic and industry conditions, the risk characteristics of its underlying assets and its growth opportunities. It strives to continuously improve its credit rating and reduce its cost of capital. Connacher monitors its capital structure using a number of financial ratios and industry metrics to ensure its objectives are being met and to ensure continued compliance with financial covenants.

Connacher's capital structure and certain financial ratios are noted below:

(\$000)	March 31, 2010	December 31, 2009
Long-term debt ⁽¹⁾	\$ 851,978	\$ 876,181
Shareholders' equity		
Share capital, contributed surplus and equity component	634,460	638,222
Accumulated other comprehensive loss	(20,828)	(16,178)
Retained earnings	55,090	49,544
Total book capitalization	\$ 1,520,700	\$ 1,547,769
Debt to book capitalization ⁽²⁾	56%	57%
Debt to market capitalization ⁽³⁾	57%	62%

(1) Long-term debt is stated at its carrying value, which is net of transaction costs and the Convertible Debentures' equity component value.

(2) Calculated as long-term debt divided by the book value of shareholders' equity plus long-term debt.

(3) Calculated as long-term debt divided by the period end market value of shareholders' equity plus long-term debt.

As at March 31, 2010, the company's net debt (long-term debt, net of cash on hand) was \$734 million. Its net debt to book capitalization was 48 percent and its net debt to market capitalization was 53 percent.

The company reported the following debt outstanding:

(\$000)	March 31, 2010	December 31, 2009
First Lien Senior Notes, 11 ¾%, due July 15, 2014	\$ 185,758	\$ 191,509
Second Lien Senior Notes, 10 ¼%, due December 15, 2015	576,689	596,184
Convertible Debentures, 4 ¾%, due June 30, 2012	89,531	88,488
Total – no current maturities	\$ 851,978	\$ 876,181

OUTLOOK

We expect stronger financial results in 2010 compared to 2009, due to anticipated improved operating performance at Pod One; higher and more stabilized commodity prices (supported by our hedging program); the anticipation of increased production and sales volumes as Algar comes on stream in the latter part of 2010 and due to increased contributions from our refining operations, which anticipates healthy asphalt markets. MRCI currently has contracted asphalt sales of approximately 580,000 bbls at prices approximating US\$100/bbl for 2010.

Current cash balances, together with available unused revolving lines of banking credit and positive full year upstream netbacks and downstream margins, are anticipated to be sufficient to meet all our budgeted capital expenditures and ongoing financial obligations throughout 2010. We have identified reserves and resources to support our confidence in our future growth prospects. To stabilize our outlook in a volatile period and protect against the possibility of renewed crude oil price weakness, we have arranged WTI derivative hedges on approximately one half of our upstream liquids production throughout 2010 and Q1 2011 and on a portion of our refined gasoline sales. Relative to our consumption of natural gas at Pod One and the Refinery, we currently have a built-in physical hedge with our own natural gas production in northern Alberta. Currently, this minimizes the impact of volatility to natural gas prices on our overall operations.

Based on year to date expenditures and current development plans, the company has reduced its previously stated 2010 capital budget from \$256 million to \$247 million. Details of 2010 projected capital expenditures are as follows:

(\$millions)	
Complete Algar	\$ 78
Algar capitalized interest, G&A and pre-commercial operations	43
Algar ESP pre-work and facility optimization	8
Cogeneration and sales transfer lines	22
Pod One, including two new SAGD wells, nine downhole pumps and facility optimization	26
EIA application	2
Expand Pod One trucking terminal	5
Oilsands and conventional exploration program	28
Conventional and head office capital	17
Refinery, including benzene removal project and steam boiler replacement	18
	\$ 247

The company's business plan anticipates long-term growth, with continued increases in revenue and cash flow from Pod One, conventional crude oil and natural gas production, while completing the Algar project and the continued expansion of our business.

Future cash flows will be substantially sheltered from current cash taxes by the company's tax pools, which currently exceed \$1.2 billion and which will be augmented by future capital expenditures.

ESTIMATED 2010 NETBACKS AND ADJUSTED EBITDA

In our 2009 MD&A as contained in our annual report and as filed separately on SEDAR, we provided guidance with regard to Connacher's estimated 2010 adjusted EBITDA per barrel of bitumen produced and sold (the "original estimate"). Estimated 2010 netbacks, refinery margin and adjusted EBITDA are calculated on an annual basis and, consequently, quarterly netbacks, refinery margin and adjusted EBITDA per barrel of bitumen sold will vary from the average annual estimates. The table below compares the company's consolidated results for Q1 2010 to those annual estimates. Explanations for variances are provided below the table.

The table below also contains a revised estimate for full year 2010 adjusted EBITDA per barrel of bitumen produced and sold based on actual results to March 31, 2010 and revised assumptions, reflecting current industry and market information (the "revised estimate"). An explanation of the revised assumptions is provided under the tables below.

	Q1 2010 actual results		Estimated Full Year 2010 Adjusted EBITDA			
			Original estimate		Revised estimate	
	\$/bbl of bitumen	Total (\$ millions)	\$/bbl of bitumen	Total (\$ millions)	\$/bbl of bitumen	Total (\$ millions)
Bitumen netback	\$ 30.47	\$ 19	\$ 31.05	\$ 117	\$ 32.67	\$ 122
Conventional netback	9.11	6	4.94	18	4.91	18
Refinery margin	(7.53)	(5)	3.19	12	3.10	12
Realized gain (loss) on risk management contracts	(0.27)	(-)	0.89	3	(0.52)	(2)
Corporate netback	31.78	20	40.07	150	40.16	150
Corporate G&A	(8.89)	(6)	(5.14)	(19)	(4.92)	(19)
Adjusted EBITDA	\$ 22.89	\$ 14	\$ 34.93	\$ 131	\$ 35.24	\$ 131

On a per barrel basis, bitumen netback was lower in Q1 2010 than originally estimated for fiscal year 2010. Higher WTI pricing and narrower heavy oil differentials in Q1 2010 were more than offset by higher transportation costs, a stronger Canadian dollar, higher royalties and higher operating costs per barrel due to actual bitumen production and sales volumes (6,936 bbl/d in Q1 2010) being lower than the original full year average bitumen production estimate of 10,240 bbl/d. Incremental bitumen production volumes are anticipated at Pod One and Algar over the balance of the year.

Q1 2010 conventional netback per barrel of bitumen was higher than originally estimated primarily due to lower actual Q1 2010 bitumen production compared to the company's original 2010 annual estimate.

Q1 2010 refinery margin per barrel of bitumen was lower than the original 2010 annual average primarily due to seasonality effects on refined product sales volumes, narrower heavy oil differentials and higher input crude costs.

On a per barrel of bitumen basis, Q1 2010 realized losses on risk management contracts were higher than originally estimated primarily due to a higher WTI crude oil price than originally estimated for the year.

Q1 2010 Corporate G&A on a per barrel of bitumen basis was higher than originally estimated primarily due to lower actual Q1 2010 bitumen production compared to the company's original 2010 annual estimate.

Actual Q1 2010 adjusted EBITDA of \$14 million was in line with that portion of the company's original 2010 annual estimate. Our revised full year estimate of adjusted EBITDA continues to be \$131 million.

The following table reconciles actual Q1 2010 adjusted EBITDA per barrel of bitumen and in total to actual Q1 2010 net earnings:

	\$/bbl of bitumen	Total (\$ millions)
Adjusted EBITDA	\$22.89	\$14.3
Interest and other income	0.11	-
Unrealized loss on risk management contracts	(2.23)	(1.4)
Stock-based compensation	(3.03)	(1.9)
Finance charges	(20.39)	(12.7)
Foreign exchange gain	38.36	23.9
Depletion, depreciation and accretion	(29.82)	(18.6)
Income taxes	4.04	2.5
Equity interest in Petrolifera loss	(1.04)	(0.6)
Net earnings	\$8.89	\$5.5

The following tables are calculated on an annualized basis and may not reflect actual quarterly netbacks, refinery margins or adjusted EBITDA. Volatility in quarterly netbacks, refinery margins and adjusted EBITDA will occur due to, among other things, seasonality factors affecting our operations, especially in our refining operations. Estimated 2010 bitumen netbacks and 2010 adjusted EBITDA constitute forward-looking information. See "Forward-Looking Information" and "Risk Factors" sections in this MD&A and in our AIF. The key assumptions relating to the 2010 outlook are set out in the notes following the tables below. The revised estimated full year 2010 bitumen netback and full year 2010 adjusted EBITDA reflected below include actual results for Q1 2010 and forecast results for the balance of 2010. The revised estimated full year bitumen netback and full year 2010 adjusted EBITDA will form the basis of comparison for future reporting periods.

REVISED ESTIMATED FULL YEAR 2010 BITUMEN NETBACK ⁽¹⁾

	Total \$/bbl of bitumen
US\$79.85/bbl Average WTI Price	
Bitumen price at wellhead ^(2,3)	\$ 49.30
Royalties ⁽⁴⁾	(2.03)
Operating costs	
Natural gas ⁽⁵⁾	(5.27)
Other operating costs ⁽⁶⁾	(9.33)
Bitumen netback	\$ 32.67

- (1) Assumes estimated total average daily bitumen production of 10,185 bbl/d in 2010; 8,500 bbl/d from Pod One and 1,685 bbl/d from Algar and has not been adjusted for inflation. See "Forward-Looking Information" and "Risk Factors" sections of our AIF. Production from Algar assumes commerciality is declared effective October 1, 2010 and has been annualized for calendar 2010.
- (2) Based on average WTI price of US\$79.85/bbl, a heavy oil differential of US\$10.62/bbl (average of 13.3 percent) and a quality charge of \$5.47/bbl, resulting in a dilbit price of \$65.00/bbl. Also assumes an average foreign exchange rate of \$1.02 = US\$1.00.
- (3) The assumed bitumen price at the wellhead of \$49.79/bbl for Pod One and \$46.81/bbl for Algar is net of dilbit transportation costs of \$6.07/bbl of bitumen and assumed diluent blending cost of \$30.68/bbl of bitumen (\$23.01/bbl of dilbit), including \$1.80/bbl of bitumen of diluent transportation costs (\$5.40/bbl of diluent), a 7.4 percent average diluent premium to WTI and a blending ratio of 25 percent for Pod One; and a diluent blending cost of \$39.02/bbl of bitumen (\$27.13/bbl of dilbit), including \$2.31/bbl of bitumen of diluent transportation costs, (\$5.40/bbl of diluent) a six percent average diluent premium to WTI and a blending ratio of 30 percent for Algar.
- (4) Royalties are calculated on a pre-payout basis and are estimated to be \$2.06/bbl for Pod One and \$1.91/bbl for Algar.
- (5) Based on an average SOR of 3.2 for Pod One and 3.4 for Algar and a natural gas price of US\$4.16/Mcf which equates to \$5.25/bbl or approximately 10,572 Mcf/d of natural gas burned to produce 8,500 bbl/d of bitumen at Pod One and a natural gas price of US \$3.92/Mcf which equates to \$5.40/bbl or approximately 2,274 Mcf/d of natural gas burned to produce 1,685 bbl/d of bitumen at Algar. The SORs for Pod One are a conservative estimate reflecting the impact of higher SORs experienced to date in the five north wells of Pad 101 and the impact of steaming the two new SAGD well pairs planned in 2010. The SORs from Algar reflect the relative infancy of the SAGD well pairs and are expected to trend down as the wells are optimized and as ESPs are added.
- (6) Assumes \$9.18/bbl of other operating costs for Pod One and \$10.07/bbl of other operating costs at Algar.

REVISED ESTIMATED FULL YEAR 2010 ADJUSTED EBITDA ⁽¹⁾

	Total \$/bbl of bitumen	Total (\$millions)
US\$79.85/bbl Average WTI Price		
Corporate netback contribution		
Bitumen netback ⁽²⁾	\$ 32.67	\$ 122
Conventional netback ⁽³⁾	4.91	18
Refinery margin ⁽⁴⁾	3.10	12
Realized loss on risk management contracts ⁽⁵⁾	(0.52)	(2)
Corporate netback	40.16	150
Corporate G&A ⁽⁶⁾	(4.92)	(19)
Adjusted EBITDA	\$ 35.24	\$ 131

- (1) Assumes estimated total average daily bitumen production of 10,185 bbl/d in 2010; 8,500 bbl/d from Pod One and 1,685 bbl/d from Algar and has not been adjusted for inflation. Also assumes an average foreign exchange rate of \$1.02 = US\$1.00.
- (2) See the table above for assumptions.
- (3) Assumes estimated production of 963 bbl/d of conventional crude oil and 8,956 Mcf/d of natural gas production. Conventional oil assets anticipated revenue based on average realized oil price of US\$70.13/bbl and natural gas assets revenue based on average realized natural gas price of US\$4.16/Mcf. Conventional asset netback is based on 24 percent average royalty rate and average operating costs of \$12.65/boe.
- (4) Assumes estimated refinery crude charged of 9,800 bbl/d, feedstock purchased at US\$74.85/bbl, refined products sold with a spread to WTI of US\$6.60/bbl and operating costs of US\$8.39/bbl, implying a refining margin of US\$3.21/bbl of crude charged.
- (5) Anticipated cost from a US\$78.00/bbl WTI swap on 2,500 bbl/d of bitumen production for calendar 2010 and a US\$79.02/bbl WTI swap on 2,500 bbl/d of bitumen production from February to April, 2010.
- (6) Excludes capitalized G&A of \$1.56/bbl of bitumen.

Actual netbacks, refinery margins and adjusted EBITDA achieved during 2010 could differ materially from the estimates contained in our 2010 outlook. The material risk factors that we have identified toward achieving these future netbacks and adjusted EBITDA are outlined in the "Risk Factors" and "Forward-Looking Information" sections of our 2009 annual MD&A and in our AIF and include, without limitation, difficulties or interruptions and additional costs during the production of bitumen, crude oil and natural gas; we may encounter timing difficulties or delays and additional costs relating to the commissioning, steaming or start-up of the Algar project; we may experience difficulties in delivering diluent to our oil sands projects and dilbit to commercial markets; the performance and availability of facilities owned by third parties may adversely affect our operations; crude oil and natural gas prices may fluctuate from current estimates; there may be changes in refining spreads to WTI and changes in the differential pricing between heavy and light crude oil prices; there may be adverse currency fluctuations; general economic conditions may remain uncertain or volatile thus affecting demand for our products and/or the costs for labour, equipment and services and changes in, or the introduction of new, government regulations relating to our business may increase operating costs.

SENSITIVITY ANALYSIS

The following table shows sensitivities to adjusted EBITDA for changes to oil prices, production volumes and foreign exchange rates. The analysis is based on recent prices and production volumes.

	Change		\$ million		\$/share ⁽¹⁾
WTI price	US\$5.00/bbl	\$	6.5	\$	0.02
Bitumen production	500 bbl/d	\$	5	\$	0.01
Exchange rate (U.S./Canadian)	\$ 0.05	\$	11	\$	0.03

(1) Based on 428 million shares outstanding at March 31, 2010.

Information relating to Connacher, including Connacher's AIF is on SEDAR at www.sedar.com. See also the company's website at www.connacheroil.com.

INTERNATIONAL FINANCIAL REPORTING STANDARDS

In early 2009, the Canadian Accounting Standards Board confirmed that publicly accountable enterprises (which would include Connacher) will be required to adopt international financial reporting standards ("IFRS") in place of Canadian Generally Accepted Accounting Principles ("Canadian GAAP") for interim and annual reporting purposes for fiscal years beginning on January 1, 2011. The impact of this change in accounting principles on our future financial position and results of operations is not quantifiable at the present time.

We have commenced our IFRS conversion project which consists of four phases: diagnostic; design and planning; solution development; and implementation. Regular progress reporting is provided to our Audit Committee and the Board of Directors.

We have completed the diagnostic phase which involved a review of the differences between current Canadian GAAP and IFRS. During this phase we determined that the differences which will have the greatest impact on Connacher's consolidated financial statements relate to accounting for exploration and development activities and property, plant and equipment, impairments of property, plant and equipment and goodwill, and asset retirement obligations. There will also be impacts on the future income tax balances associated with balance sheet items affected by the transition to IFRS.

We have also completed the design and planning and solution development phases, including testing of modifications made to our accounting and financial reporting systems to deal with the requirements of IFRS for the purpose of running in parallel during 2010 so as to generate IFRS comparative figures for reporting in 2011. During these phases, we have also been providing training to staff, management and Directors on international accounting and financial reporting standards and the impact they are having on our accounting processes and procedures.

Recently, we commenced the implementation phase and have engaged in ongoing discussions with our auditors and Audit Committee regarding revisions to our accounting policies to conform to IFRS. During this phase we will evaluate alternatives to the IFRS 1 transitional exemptions available for use in preparing our opening IFRS balance sheet. One such exemption we expect to utilize is the amendment issued by the International Accounting Standards Board (IASB) in July 2009 respecting the determination of opening balances of property, plant and equipment. That amendment permits oil and gas companies currently using the full cost method of accounting to allocate the balance of property, plant and equipment as determined under Canadian GAAP to the IFRS categories of exploration and evaluation assets and development and producing properties without requiring full retroactive restatement of historic balances to the IFRS basis of accounting. During this phase we will also evaluate the impact that system and procedural changes will have on our disclosure controls and procedures and on our internal controls over financial reporting.

We continue to actively monitor changes to international accounting and reporting standards and have provided comments to the IASB on some of their recently proposed changes. In addition, we continue to follow the efforts of, and participate with, some industry peer companies in the IFRS transition process to coordinate our efforts with them and to ensure that our policies will be consistent with IFRS adopted by other companies in our industry.

RISK FACTORS AND RISK MANAGEMENT

Connacher is engaged in the oil and gas exploration, development, production, and refining industry. This business is inherently risky and there is no assurance that hydrocarbon reserves will be discovered and economically produced. Operational risks include competition, reservoir performance uncertainties, environmental factors, and regulatory and safety concerns. Financial risks associated with the petroleum industry include fluctuations in commodity prices, interest rates, currency exchange rates and the cost of goods and services.

Connacher's financial and operating performance is potentially affected by a number of factors including, but not limited to, risks associated with the oil and gas industry, commodity prices and exchange rates, environmental legislation, changes to royalty and income tax legislation, credit and capital market conditions, credit risk for failure of performance of third parties and other risks and uncertainties described in more detail in Connacher's AIF for the year ended December 31, 2009 filed with securities regulatory authorities.

Connacher employs highly qualified people, uses sound operating and business practices and evaluates all potential and existing wells using the latest applicable technology. The company has designed policies and procedures for compliance with government regulations and has in place an up-to-date emergency response program. Connacher monitors and seeks to adhere to environment and safety policies and standards. Asset retirement obligations are recognized upon acquisition, construction and development of the assets. Connacher maintains property and liability insurance coverage. The coverage provides a reasonable amount of protection from risk of loss; however, not all risks are foreseeable or insurable.

DISCLOSURE CONTROLS AND PROCEDURES

The company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the company is made known to the company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of the company's financial reporting and the preparation of financial statements for external purposes in accordance with Canadian GAAP.

The company's CEO and CFO are required to cause the company to disclose any change in the company's internal controls over financial reporting that occurred during the company's most recent interim period that has materially affected, or is reasonably likely to materially affect, the company's internal controls over financial reporting. No material changes in the company's internal controls over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the company's internal controls over financial reporting.

It should be noted that a control system, including the company's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud. In reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures.

QUARTERLY RESULTS

Fluctuations in results over the previous eight quarters are due principally to variations in oil and gas prices, production and sales volumes and foreign exchange rates relative to U.S. dollar denominated debt. Significant volatility and declining commodity prices, together with severe economic uncertainty in the fourth quarter of 2008 and Q1 2009 are the primary factors affecting financial results during those quarters. The magnitude of the changes in commodity prices during these periods was unprecedented.

(\$000 except per share amounts)	2008	2008	2008	2009	2009	2009	2009	2010
Three Months Ended	Jun 30	Sept 30	Dec 31	Mar 31	Jun 30	Sept 30	Dec 31	Mar 31
Revenues, net of royalties	202,016	224,558	102,109	61,757	100,219	151,360	108,354	118,411
Cash flow ⁽¹⁾	20,550	31,130	(4,688)	(4,692)	9,570	10,410	(2,766)	3,948
Basic, per share ⁽¹⁾	0.10	0.15	(0.02)	(0.02)	0.04	0.03	(0.07)	0.01
Diluted, per share ⁽¹⁾	0.10	0.14	(0.02)	(0.02)	0.03	0.03	(0.06)	0.01
Net earnings (loss)	6,683	12,139	(43,592)	(46,844)	39,966	47,767	(14,731)	5,546
Basic per share	0.03	0.06	(0.21)	(0.22)	0.15	0.12	(0.03)	0.01
Diluted per share	-	-	-	-	0.14	0.11	-	0.01
Property and equipment additions	80,403	69,175	86,174	64,255	40,236	100,727	116,846	118,272
Cash on hand	232,704	236,375	223,663	96,220	401,160	333,634	256,787	118,382
Working capital surplus	234,110	200,177	197,914	120,035	455,001	347,139	245,067	127,186
Long-term debt	684,705	689,673	778,732	803,915	960,593	889,113	876,181	851,978
Shareholders' equity	479,477	496,509	469,087	428,276	622,235	658,336	671,588	668,722
Operating Information								
Upstream: Daily production/sales volumes								
Bitumen – bbl/d	6,123	6,810	7,086	6,170	6,284	6,551	6,090	6,936
Crude oil – bbl/d	981	957	1,187	1,180	1,114	993	880	937
Natural gas – Mcf/d	14,220	13,188	12,405	12,828	12,144	10,377	10,319	9,662
Equivalent – boe/d ⁽²⁾	9,474	9,966	10,341	9,488	9,421	9,274	8,690	9,483
Product sales prices ⁽³⁾								
Bitumen – \$/bbl	60.80	65.34	12.06	22.45	40.95	45.30	48.23	51.98
Crude oil – \$/bbl	105.28	103.60	48.13	39.63	54.87	60.58	67.24	71.08
Natural gas – \$/Mcf	8.77	8.92	6.61	4.89	3.35	2.91	4.34	4.86
Selected highlights – \$/boe ⁽²⁾								
Weighted average sales price ⁽³⁾	65.25	66.41	21.73	26.13	38.11	41.74	45.76	49.99
Royalties	6.21	4.65	3.19	3.02	1.90	2.13	2.45	3.57
Operating costs	22.78	20.41	20.76	17.73	13.98	15.43	20.61	17.47
Netback ⁽⁴⁾	36.26	41.35	(2.22)	5.38	22.23	24.18	22.70	28.95
Downstream:								
Refining throughput crude charged – bbl/d	9,329	9,239	8,333	6,867	9,145	7,076	8,188	9,347
Refining utilization – %	98	97	88	72	96	75	86	98
Margins – %	(0.1)	2	(18)	7	5	8	(7)	(8)
Common Share Information								
Shares outstanding end of period (000)	211,027	211,182	211,182	211,291	403,546	403,567	427,031	428,246
Weighted average shares outstanding for the period								
Basic (000)	210,658	211,093	211,182	211,286	266,425	403,565	421,804	427,830
Diluted (000)	214,530	213,174	211,575	211,286	286,985	424,058	422,344	430,077
Volume traded (000)	107,001	112,401	110,244	67,387	249,700	129,206	207,978	167,483
Common share price (\$)								
High	5.26	4.65	2.95	1.00	1.66	1.15	1.33	1.65
Low	3.10	2.63	0.60	0.61	0.74	0.76	0.94	1.16
Close (end of period)	4.30	2.75	0.74	0.74	0.92	1.10	1.28	1.49

(1) Cash flow and cash flow per share do not have standardized meanings prescribed by Canadian generally accepted accounting principles ("GAAP") and therefore may not be comparable to similar measures used by other companies. Cash flow is calculated before changes in non-cash working capital, pension funding and asset retirement expenditures. The most comparable measure calculated in accordance with GAAP would be cash flow from operating activities. Cash flow is reconciled with cash flow from operating activities on the Consolidated Statement of Cash Flows and in the applicable Management Discussion & Analysis ("MD&A") for the periods referenced. Management uses these non-GAAP measurements for its own performance measures and to provide its shareholders and investors with a measurement of the company's efficiency and its ability to fund its future growth expenditures.

(2) All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf: 1 bbl. This conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation.

(3) Product and weighted average sales prices are net of transportation costs and exclude risk management contract gains / losses.

(4) Netback is a non-GAAP measure used by management as a measure of operating efficiency and profitability. Cash operating netback per boe is calculated as bitumen, crude oil and natural gas revenue before consideration of risk management contracts/losses, less royalties and operating costs divided by related production/sales volume. Netbacks have been reconciled to net earnings in the applicable MD&A for the periods referenced.

CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

(Canadian dollar in thousands) As at	March 31, 2010	December 31, 2009
ASSETS		
CURRENT		
Cash	\$ 118,382	\$ 256,787
Accounts receivable	40,251	43,038
Inventories	49,814	36,871
Due from Petrolifera Petroleum Limited	18	29
Prepaid expenses and other assets	17,235	15,874
Income taxes recoverable	-	2,608
	225,700	355,207
Property, plant and equipment	1,327,988	1,230,256
Goodwill	103,676	103,676
Investment in Petrolifera Petroleum Limited	49,759	50,379
	\$ 1,707,123	\$ 1,739,518
LIABILITIES AND SHAREHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	\$ 92,602	\$ 105,620
Risk management contracts (note 8.2)	5,912	4,520
	98,514	110,140
Long-term debt (note 3)	851,978	876,181
Future income taxes	52,188	47,695
Asset retirement obligations (note 5)	34,539	32,848
Employee future benefits	1,182	1,066
	1,038,401	1,067,930
SHAREHOLDERS' EQUITY		
Share capital (note 6)	585,085	590,845
Equity component of convertible debentures	16,817	16,817
Contributed surplus (note 7)	32,558	30,560
Retained earnings	55,090	49,544
Accumulated other comprehensive loss	(20,828)	(16,178)
	668,722	671,588
	\$ 1,707,123	\$ 1,739,518

Subsequent events (notes 8.2 and 13)

The accompanying notes to the interim consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF OPERATIONS AND RETAINED EARNINGS (DEFICIT)

(UNAUDITED)

(Canadian dollar in thousands, except per share amounts)	2010	2009
REVENUE		
Upstream, net of royalties	\$ 62,353	\$ 36,007
Downstream	57,551	32,683
Loss on risk management contracts (note 8.2)	(1,564)	(7,861)
Interest and other income	71	928
	118,411	61,757
EXPENSES		
Upstream – diluent purchases and operating costs	30,392	28,036
Upstream transportation costs	3,214	2,907
Downstream – crude oil purchases and operating costs	66,289	30,720
General and administrative	5,552	4,474
Stock-based compensation (note 7)	1,891	1,270
Finance charges (note 11)	12,729	9,160
Foreign exchange (gain) loss (note 8.2)	(23,943)	27,866
Depletion, depreciation and accretion	18,617	16,449
	114,741	120,882
Earnings (loss) before income taxes and other items	3,670	(59,125)
Current income tax provision	206	172
Future income tax recovery	(2,730)	(12,170)
	(2,524)	(11,998)
Earnings (loss) before other items	6,194	(47,127)
Equity interest in Petrolifera Petroleum Limited's (loss) earnings	(648)	283
NET EARNINGS (LOSS)	5,546	(46,844)
Retained earnings, beginning of period	49,544	23,386
Retained earnings (deficit), end of period	\$ 55,090	\$ (23,458)
EARNINGS (LOSS) PER SHARE (note 6.3)		
Basic and Diluted	\$ 0.01	\$ (0.22)

The accompanying notes to the interim consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(UNAUDITED)

(Canadian dollar in thousands)	2010	2009
Net earnings (loss)	\$ 5,546	\$ (46,844)
Foreign currency translation adjustment	(4,650)	4,431
Comprehensive income (loss)	\$ 896	\$ (42,413)

CONSOLIDATED STATEMENTS OF ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

(UNAUDITED)

(Canadian dollar in thousands)	2010	2009
Balance, beginning of period	\$ (16,178)	\$ 7,802
Foreign currency translation adjustment	(4,650)	4,431
Balance, end of period	\$ (20,828)	\$ 12,233

The accompanying notes to the interim consolidated financial statements are an integral part of these statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

(UNAUDITED)

(Canadian dollar in thousands)	2010	2009
Cash provided by (used in) the following activities:		
OPERATING		
Net earnings (loss)	\$ 5,546	\$ (46,844)
Items not involving cash:		
Depletion, depreciation and accretion	18,617	16,449
Stock-based compensation	1,891	1,270
Financing charges - non-cash portion	1,437	1,041
Defined benefit pension plan expense	155	187
Future income tax recovery	(2,730)	(12,170)
Unrealized loss on risk management contracts (note 8.2)	1,392	8,267
Gain on repurchase of Second Lien Senior Notes	-	(475)
Equity interest in Petrolifera Petroleum Limited's loss (earnings)	648	(283)
Unrealized foreign exchange (gain) loss (note 8.2)	(23,008)	27,866
Cash flow from operations before working capital and other changes	3,948	(4,692)
Asset retirement expenditures (note 5)	(368)	(104)
Changes in non-cash working capital	(11,879)	(24,304)
	(8,299)	(29,100)
FINANCING		
Proceeds on issue of common shares (note 6.1)	1,533	-
Share issue costs	(80)	-
Repurchase of Second Lien Senior Notes	-	(309)
	1,453	(309)
INVESTING		
Capital expenditures	(116,795)	(63,144)
Proceeds on disposition of property, plant and equipment	1,205	-
Increase in restricted cash	-	(10,000)
Changes in non-cash working capital	(11,707)	(35,368)
	(127,297)	(108,512)
NET DECREASE IN CASH	(134,143)	(137,921)
Foreign exchange (loss) gain on cash balances held in foreign currency	(4,262)	478
CASH, BEGINNING OF PERIOD	256,787	223,663
CASH, END OF PERIOD	\$ 118,382	\$ 86,220

For supplementary cash flow information – see note 12

The accompanying notes to the interim consolidated financial statements are an integral part of these statements.

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

I. NATURE OF OPERATIONS AND ORGANIZATION

Connacher Oil and Gas Limited ("Connacher" or "the company") is a publicly traded and integrated energy company headquartered in Calgary, Alberta, Canada.

Management has segmented the company's business based on differences in products and services and management responsibility. The company's business is conducted predominantly through two major business segments – upstream in Canada and downstream in USA, through its wholly owned subsidiary, Montana Refining Company, Inc. ("MRCI").

Upstream includes exploration for, development and production of crude oil, natural gas and bitumen. Downstream includes refining of primarily crude oil to produce and market gasoline, jet fuel, diesel fuels, asphalt and ancillary products.

The company also has an investment in Petrolifera Petroleum Limited ("Petrolifera") which has been accounted for on the equity basis. As at March 31, 2010 and December 31, 2009, the company owned 26.9 million Petrolifera common shares representing 22 percent of Petrolifera's issued and outstanding common shares and 6.8 million Petrolifera share purchase warrants. Petrolifera is engaged in petroleum and natural gas exploration, development and production activities in South America.

2. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements were prepared in accordance with Canadian generally accepted accounting standards and follow the same accounting policies and methods of computation as the most recent annual consolidated financial statements. Certain information and disclosures normally required to be included in notes to the annual consolidated financial statements have been condensed or omitted. Accordingly, these interim consolidated financial statements should be read in conjunction with the annual consolidated financial statements and the notes thereto for the year ended December 31, 2009.

In the opinion of management, these interim consolidated financial statements contain all adjustments of a normal and recurring nature necessary to present fairly Connacher's financial position at March 31, 2010 and December 31, 2009 and the results of its operations and cash flows for the three month periods ended March 31, 2010 and 2009.

3. LONG-TERM DEBT

(Canadian dollar in thousands)	March 31, 2010	December 31, 2009
First Lien Senior Notes	\$ 185,758	\$ 191,509
Second Lien Senior Notes	576,689	596,184
Convertible Debentures	89,531	88,488
Long-term debt	\$ 851,978	\$ 876,181

The following table provides the key terms and conditions of the long-term debt:

	Face Value of Principal (in millions)	Maturity Date	Interest Rate per annum	Interest Payment Terms	Principal Payment Terms
First Lien Senior Notes (Secured)	US\$ 200	July 15, 2014	11.75%	Semi-annually on January 15 and July 15	One payment on maturity (note 3.1)
Second Lien Senior Notes (Secured)	US\$ 587.3	December 15, 2015	10.25%	Semi-annually on June 15 and December 15	One payment on maturity (note 3.1)
Convertible Debentures (Unsecured)	\$100	June 30, 2012 unless converted prior to that date	4.75%	Semi-annually on June 30 and December 31	Convertible into common shares at a conversion price of \$5.00 per share (note 3.1)

3.1 The company may redeem some or all of the First and Second Lien Senior Notes and Convertible Debentures prior to their maturity. Upon a change of control of the company, Connacher is obliged to offer to purchase the outstanding Convertible Debentures; additionally, the holders of the First and Second Lien Senior Notes may require Connacher to purchase the Notes. There were no changes to the terms and conditions of the long-term debt during three months ended March 31, 2010.

4. REVOLVING CREDIT FACILITY

As at March 31, 2010, the company had a US\$50 million revolving credit facility (the "Facility"). The Facility has a two year term starting from November 2009 and ranks ahead of the company's First and Second Lien Senior Notes. It is secured by a first lien charge on all of the company's assets, excluding certain pipeline assets in the USA and the company's investment holdings in Petrolifera. The Facility bears interest at the lenders' Canadian prime rate, a U.S. base rate, a Bankers' Acceptance rate, or at a LIBOR rate plus applicable margins. The Facility contains certain covenants that, if not met, give the lender the ability to cancel the Facility. As of March 31, 2010, the company was in compliance with these covenants. At March 31, 2010, \$5.7 million of letters of credit were issued pursuant to the Facility.

5. ASSET RETIREMENT OBLIGATIONS

The following table reconciles the beginning and ending aggregate carrying amount of the obligation associated with the company's retirement of its upstream crude oil, natural gas and oil sands properties and facilities:

(Canadian dollar in thousands)	Three months ended March 31, 2010	Year ended December 31, 2009
Balance, beginning of period	\$ 32,848	\$ 26,396
Liabilities incurred	1,647	6,194
Liabilities settled	(368)	(142)
Liabilities disposed off	(264)	-
Change in estimates	-	(1,803)
Accretion expense	676	2,203
Balance, end of period	\$ 34,539	\$ 32,848

At March 31, 2010, the estimated total undiscounted amount required to settle the asset retirement obligations was \$77.4 million (December 31, 2009 – \$72.0 million). The company has not recorded an asset retirement obligation for its refining property, plant and equipment as it is currently the company'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.

6. SHARE

Authorized unlimited number of common voting shares

Authorized unlimited number of first preferred shares of which none were outstanding

Authorized unlimited number of second preferred shares of which none were outstanding

6.1 ISSUED AND OUTSTANDING COMMON SHARE CAPITAL

	Number of shares	Amount (Canadian dollar in thousands)
Balance, beginning of period	427,031,362	\$ 590,845
Shares issued upon exercise of stock options (note 7.2)	575,738	531
Assigned value of stock options exercised (note 7.1)		315
Shares issued to directors as compensation (note 7.3)	638,496	1,002
Share issue cost, net of future income tax		(59)
Tax effect of flow-through shares (note 6.2)		(7,549)
Balance, end of period	428,245,596	\$ 585,085

6.2 In October 2009, the company issued 23,172,500 common shares on a flow-through basis at \$1.30 per common share for gross proceeds of \$30.1 million and renounced the qualifying expenditures to investors effective December 31, 2009. The related tax effect of \$7.5 million was recorded in the three months ended March 31, 2010.

6.3 PER SHARE AMOUNTS

The following table summarizes the common shares used in per share calculations for the three months ended March 31:

(000)	2010	2009
Weighted average common shares outstanding – basic	427,830	211,286
Dilutive effect of weighted average stock options outstanding	2,195	-
Dilutive effect of weighted average non-employee share awards outstanding	52	-
Weighted average common shares outstanding – diluted	430,077	211,286

7. CONTRIBUTED SURPLUS, STOCK OPTIONS AND SHARE AWARD PLAN FOR NON-EMPLOYEE DIRECTORS

7.1 CONTRIBUTED SURPLUS

The following table shows the changes in contributed surplus:

(Canadian dollar in thousands)	Three months ended March 31, 2010	Year ended December 31, 2009
Balance, beginning of period	\$ 30,560	\$ 26,053
Stock based compensation expense	1,661	3,594
Stock based compensation capitalized	652	1,096
Assigned value of stock options exercised	(315)	(183)
Balance, end of period	\$ 32,558	\$ 30,560

7.2 STOCK OPTIONS

The stock options have a term of five years to maturity and vest over the period of two to three years. The following table shows the changes in stock options during the first quarters of each of 2010 and 2009 and the related weighted average exercise price:

	2010		2009	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	22,579,045	\$ 1.72	16,383,104	\$ 3.16
Granted	7,857,619	1.34	4,233,500	0.71
Exercised	(575,738)	0.92	-	-
Forfeited	(32,412)	1.14	(167,484)	3.99
Expired	(669,000)	3.54	(190,000)	1.35
Outstanding, end of period	29,159,514	\$ 1.59	20,259,120	\$ 2.66
Exercisable, end of period	15,141,698	\$ 1.95	14,403,439	\$ 3.18

The following table summarizes stock options outstanding and exercisable under the plan at March 31:

Range of Exercise Prices	2010			2009		
	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Number Outstanding	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life
\$0.20 – \$0.99	4,697,600	\$ 0.75	3.7	5,222,534	\$ 0.72	4.2
\$1.00 – \$1.99	18,845,183	1.25	4.3	4,369,758	1.34	3.6
\$2.00 – \$3.99	4,983,222	3.32	1.6	5,302,319	3.31	2.6
\$4.00 – \$5.99	633,509	4.5	1.4	5,364,509	4.98	2.0
	29,159,514	\$ 1.59	3.7	20,259,120	\$ 2.66	3.1

The fair value of each stock option granted is estimated on the date of grant using the Black–Scholes option–pricing model using the following weighted average assumptions:

	2010	2009
Three months ended March 31		
Risk free interest rate (percent)	1.87	1.3
Expected option life (years)	3.0	3.0
Expected volatility (percent)	72	67

The weighted average fair value was \$0.64 per option for the stock options granted during the three months ended March 31, 2010 (three months ended March 31, 2009 - \$0.32 per option).

7.3 SHARE AWARD PLAN FOR NON-EMPLOYEE DIRECTORS

Under the share award plan, share units may be granted to non–employee directors of the company in amounts determined by the Board of Directors on the recommendation of its Governance Committee.

	Three months ended March 31, 2010	Three months ended March 31, 2009
(Number of common shares)		
Outstanding, beginning of period	648,916	392,705
Granted	380,598	478,872
Issued	(638,496)	(108,975)
Cancelled	-	(54,662)
Outstanding, end of period	391,018	707,940
Exercisable, end of period	10,420	223,858

The 380,598 share awards granted in the first quarter of 2010 vest on January 1, 2011. The 478,872 share awards granted in the first quarter of 2009 vested on January 1, 2010.

In the three months ended March 31, 2010, \$230,000 (three months ended March 31, 2009 – \$159,000) was accrued as a liability and expense in respect of outstanding shares under the share award plan.

8. FINANCIAL INSTRUMENTS

Connacher's financial instruments include cash, accounts receivable, amounts due from Petrolifera, accounts payable and accrued liabilities, risk management contracts and long-term debt (First and Second Lien Senior Notes and Convertible Debentures).

8.1 FAIR VALUE MEASUREMENTS FOR FINANCIAL INSTRUMENTS

The following table shows the comparison of the carrying and fair values of the company's financial instruments as at March 31, 2010:

(Canadian dollar in thousands)	Carrying Value	Fair Value
Held for trading		
Cash	\$ 118,382	\$ 118,382
Accounts receivable	40,251	40,251
Due from Petrolifera	18	18
Accounts payable and accrued liabilities	92,602	92,602
Risk management contracts	5,912	5,912
Other liabilities		
First Lien Senior Notes	185,758	225,460
Second Lien Senior Notes	576,689	605,409
Convertible Debentures	\$ 89,531	\$ 94,000

8.2 RISK EXPOSURES

The company is exposed to market risks related to the volatility of commodity selling prices, foreign exchange rates and interest rates. In certain instances, the company uses derivative instruments to manage the company's exposure to these risks. The company is also exposed, to a lesser extent, to credit risk on accounts receivable and counterparties to price risk management contracts and to liquidity risk. The company employs risk management strategies and policies to ensure that any exposures to risk are in compliance with the company's business objectives and risk tolerance levels. Risk management is ultimately established by the company's Board of Directors and is implemented and monitored by senior management of the company.

At March 31, 2010, the company's exposure to risks associated with or arising from the use of financial instruments had not changed significantly from December 31, 2009.

MARKET RISK AND SENSITIVITY ANALYSIS

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of commodity price risk, foreign currency risk and interest rate risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns.

COMMODITY PRICE RISK

The company is exposed to commodity selling price risk as a result of potential changes in the market prices of its crude oil, bitumen, natural gas and refined product sales volumes and the purchase price of diluent.

The following table summarizes the change in fair value of the company's risk management contracts:

(Canadian dollar in thousands)	Three months ended March 31, 2010	Year ended December 31, 2009
Balance, beginning of period	\$ 4,520	\$ -
Unrealized loss during the period	1,392	4,520
Balance, end of period	\$ 5,912	\$ 4,520

The following table summarizes the income statement effects of the company's risk management contracts:

(Canadian dollar in thousands)	Three months ended March 31, 2010			Three months ended March 31, 2009
	Upstream Revenue	Downstream Revenue	Total	Upstream Revenue
Unrealized loss	\$ 778	\$ 614	\$ 1,392	\$ 8,267
Realized loss (gain)	172	-	172	(406)
Loss on risk management contracts	\$ 950	\$ 614	\$ 1,564	\$ 7,861

A summary of the risk management contracts outstanding as at March 31, 2010 and December 31, 2009 are presented below:

MARCH 31, 2010 – UPSTREAM OIL CONTRACTS

Volume (bb/d)	Term	Type	Price (WTI U.S.\$/bbl)	Unrealized loss (gain) as at March 31, 2010 (Canadian dollar in thousands)
2,500	Jan 1 – Dec 31, 2010	Swap	\$ 78.00	\$ 4,853
2,500	Feb 1 – Apr 30, 2010	Swap	\$ 79.02	373
2,500	May 1 – Dec 31, 2010	Call option	\$ 95.00	1,704
2,500	May 1 – Dec 31, 2010	Put option	\$ 75.00	(1,632)
Balance, as at March 31, 2010				\$ 5,298

MARCH 31, 2010 – DOWNSTREAM GASOLINE CONTRACT

Volume (bb/d)	Term	Type	Price	Unrealized loss as at March 31, 2010 (Canadian dollar in thousands)
2,000	April 1 – Sept 30, 2010	Swap	Floating price* + U.S. \$9.00/bbl	\$ 614

* Floating price is an average WTI price in US \$/bbl for the calculation period.

DECEMBER 31, 2009 – UPSTREAM OIL CONTRACTS

Volume (bb/d)	Term	Type	Price (WTI U.S.\$/bbl)	Unrealized loss as at December 31, 2009 (Canadian dollar in thousands)
2,500	Jan 1 – Dec 31, 2010	Swap	\$ 78.00	\$ 4,115
2,500	Feb 1 – Apr 30, 2010	Swap	\$ 79.02	405
Balance, as at December 31, 2009				\$ 4,520

Subsequent to March 31, 2010, the company entered into the following additional upstream risk management contracts:

Volume (bb/d)	Term	Type	Price (WTI U.S.\$/bbl)
1,000	Jan 1, 2011 – Mar 31, 2011	Swap	\$ 86.10
1,000	Jan 1, 2011 – Mar 31, 2011	Swap	\$ 88.10
2,000	Jan 1, 2011 – Mar 31, 2011	Call option	\$ 100.25
2,000	Jan 1, 2011 – Mar 31, 2011	Put option	\$ 80.00

As at March 31, 2010, had the forward price for WTI been U.S. \$1/bbl higher or lower, the impact would have been to increase or decrease, respectively, earnings before tax by \$37,000.

CURRENCY RISK

Currency risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in foreign exchange rates.

The following table summarizes the components of the company's foreign exchange (gain) loss for the three months ended March 31:

(Canadian dollar in thousands)	2010	2009
Unrealized foreign exchange (gain) loss on translation of:		
U.S. denominated First and Second Lien Senior Notes	\$ (26,613)	\$ 24,691
Foreign currency denominated cash balances	4,000	234
Foreign exchange collar (see below)	-	2,440
Other foreign currency denominated monetary items	(395)	501
Unrealized foreign exchange (gain) loss	(23,008)	27,866
Realized foreign exchange gain	(935)	-
Foreign exchange (gain) loss	\$ (23,943)	\$ 27,866

The company is exposed to fluctuations in foreign currency as a result of its U.S. dollar denominated Notes, crude oil sales based on U.S. dollar indices and commodity contracts that are settled in U.S. dollars. The company's net earnings and cash flow will therefore be impacted by fluctuations in foreign exchange rates as noted below:

(Canadian dollar in thousands)	Increase (decrease) in net earnings
Canadian Dollar weakens by \$0.01	\$ (6,666)
Canadian Dollar strengthen by \$0.01	\$ 6,666

The company's downstream operations operate with a U.S. dollar functional currency, which gives rise to currency exchange rate risk on translation of MRCI's operations. The impact is recorded in other comprehensive loss. The impact on other comprehensive loss due to the fluctuation in U.S. and Canadian dollar exchange would be as follows:

(Canadian dollar in thousands)	Increase (decrease) in other comprehensive loss
Canadian Dollar weakens by \$0.01	\$ (41)
Canadian Dollar strengthen by \$0.01	\$ 41

In November 2008, Connacher entered into a foreign exchange revenue collar for 2009 which set a floor of CAD \$11.925 million and a ceiling of CAD \$13 million on a notional amount of US\$10 million of monthly production revenue. For three months ended March 31, 2009, the unrealized foreign exchange loss of \$2.4 million was included in the net foreign exchange loss in the consolidated statement of operations in respect of this contract. No similar contract was entered in the three months ended March 31, 2010.

9. CAPITAL MANAGEMENT

The company is exposed to financial risks on its financial instruments and in the way it finances its capital requirements. The company manages these financial and capital structure risks by operating in a manner that minimizes its exposures to volatility of the company's financial performance. Connacher continues to structure its capital consistent with last year. These risks affecting the company are discussed below.

Connacher's objectives in managing its cash, debt and equity and its future capital requirements are to safeguard its ability to meet its financial obligations, to maintain a flexible capital structure that allows multiple financing options when a financing need or opportunity arises and to optimize its use of long-term debt and equity at an appropriate level of risk.

The company manages its capital structure and follows a financial strategy that considers economic and industry conditions, the risk characteristics of its underlying assets and its growth opportunities. It strives to continuously improve its credit rating and reduce its cost of capital. Connacher monitors its capital structure using a number of financial ratios and industry metrics to ensure its objectives are being met and to ensure continued compliance with its financial covenants.

Connacher's current capital structure and certain financial ratios are noted below:

(Canadian dollar in thousands)	March 31, 2010	December 31, 2009
Long-term debt ⁽¹⁾	\$ 851,978	\$ 876,181
Shareholders' equity	668,722	671,588
Total Debt plus Equity ("capitalization")	\$ 1,520,700	\$ 1,547,769
Debt to book capitalization ⁽²⁾	56%	57%
Debt to market capitalization ⁽³⁾	57%	62%

(1) Long-term debt is stated at its carrying value, which is net of transaction costs and the Convertible Debentures' equity component value.

(2) Calculated as long-term debt divided by the book value of shareholders' equity plus long-term debt.

(3) Calculated as long-term debt divided by the period end market value of shareholders' equity plus long-term debt.

As at March 31, 2010, the company's net debt (long-term debt, net of cash on hand) was \$733.6 million. Its net debt to book capitalization was 48 percent and its net debt to market capitalization was 53 percent.

10. SEGMENTED INFORMATION

The company has two business segments. In Canada, the company is in the business of exploring for and producing crude oil, natural gas and bitumen. In USA, the company is in the business of refining and marketing petroleum products. The significant information of these operating segments for the three months ended March 31 is presented below:

(Canadian dollar in thousands)	Canada	USA	Intersegment	Total
2010	Oil and Gas	Refining	Elimination ⁽¹⁾	
Net revenues	\$ 62,353	\$ 61,589	\$ (4,038)	\$ 119,904
Loss on risk management contracts	(950)	(614)	-	(1,564)
Equity interest in Petrolifera loss	(648)	-	-	(648)
Interest and other income	37	34	-	71
Finance charges	12,722	7	-	12,729
Depletion, depreciation and accretion	16,117	2,500	-	18,617
Taxes recovery	1,585	(4,109)	-	(2,524)
Net earnings (loss)	10,868	(5,322)	-	5,546
Property, plant and equipment, net	1,244,232	83,756	-	1,327,988
Goodwill	103,676	-	-	103,676
Capital expenditures	117,133	1,139	-	118,272
Total assets	\$ 1,549,075	\$ 158,048	\$ -	\$ 1,707,123
2009				
Net revenues	\$ 36,007	\$ 33,153	\$ (470)	\$ 68,690
Loss on risk management contracts	(7,861)	-	-	(7,861)
Equity interest in Petrolifera earnings	283	-	-	283
Interest and other income	734	194	-	928
Finance charges	8,857	303	-	9,160
Depletion, depreciation and accretion	14,600	1,849	-	16,449
Taxes recovery	(11,134)	(864)	-	(11,998)
Net loss	(45,651)	(1,193)	-	(46,844)
Property, plant and equipment, net	945,155	91,314	-	1,036,469
Goodwill	103,676	-	-	103,676
Capital expenditures	60,999	3,256	-	64,255
Total assets	\$ 1,221,340	\$ 164,334	\$ -	\$ 1,385,674

(1) Intersegment transactions are eliminated on consolidation.

11. FINANCE CHARGES

(Canadian dollar in thousands)	Three months ended March 31, 2010	Three months ended March 31, 2009
Interest expense on long-term debt	\$ 25,379	\$ 21,235
Amortization of transaction costs on revolving credit facility	118	481
Bank charges and other fees	-	766
	25,497	22,482
Less: Interest capitalized (note 11.1)	(12,768)	(13,322)
Finance charges – net	\$ 12,729	\$ 9,160

11.1 Interest on the First Lien Senior Notes and interest on that portion of the Second Lien Senior Notes which has been used to fund the construction of Algar project continues to be capitalized during its construction phase.

12. SUPPLEMENTARY CASH FLOW INFORMATION

(Canadian dollar in thousands)	Three months ended March 31, 2010	Three months ended March 31, 2009
Interest paid	\$ 14,000	\$ 727
Income taxes paid	\$ 105	\$ 1,344

13. SUBSEQUENT EVENT

In April 2010, Petrolifera closed a public offering of 23,678,500 common shares at a price of \$0.85 per common share for gross proceeds of \$20.1 million (the "Offering"). The company did not subscribe for shares in the Offering and accordingly, the company's equity interest in Petrolifera was reduced to 18.5 percent from 22 percent as at March 31, 2010.