CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE MONTHS ENDED SEPTEMBER 30, 2011

CANACOL ENERGY LTD.

FINANCIAL & OPERATING HIGHLIGHTS

(in United States dollars (tabular amounts in thousands) except as otherwise noted)

Financial ***Three months ended September 30:***	**2011**	2010	Change
Crude oil sales, net of royalties	**26,453**	15,219	74%
Tariff revenue	**8,877**	1,579	462%
Total revenues	**35,330**	16,798	110%
Funds from operations [(1)(2)]	**17,761**	7,766	129%
Per share – basic and diluted ($)	**0.03**	0.02	50%
Adjusted funds from operations [(1)]	**19,451**	7,766	150%
Per share – basic and diluted ($)	**0.04**	0.02	100%
Net income (loss)	**13,486**	(30,068)	n/a
Per share – basic and diluted ($)	**0.03**	(0.07)	n/a
Capital expenditures	**31,356**	8,241	280%
September 30 and June 30:	**2011**	2011	Change
Cash and cash equivalents	**108,986**	101,627	7%
Restricted cash	**6,545**	13,048	(50%)
Net working capital surplus [(1)]	**85,101**	94,547	(10%)
Total assets	**316,574**	316,570	-
Common shares, end of period (000s)	**512,953**	511,637	-
Operations ***Three months ended September 30:***	**2011**	2010	Change
Crude oil production (bopd)			
Tariff	**6,476**	1,259	414%
NRI	**3,274**	1,729	89%
Total	**9,750**	2,988	226%
Crude oil sales (bopd)			
Tariff	**6,458**	1,253	415%
NRI	**3,452**	2,418	43%
Total	**9,910**	3,671	170%
Tariff oil operating netback ($/bbl) [(1)]			
Realized tariff oil price	**14.94**	13.70	9%
Operating and transportation costs	**(6.23)**	(8.44)	(26%)
Tariff oil operating netback	**8.71**	5.26	66%
Non-tariff (NRI) oil operating netback ($/bbl) [(1)]			
Realized crude oil price, net of royalties	**84.43**	69.08	22%
Operating and transportation costs	**(29.26)**	(26.55)	10%
NRI oil operating netback	**55.17**	42.53	30%

(1) Non-IFRS measure. See "Non-IFRS Measures" section within MD&A.
(2) Includes $1.5 million of pre-license costs for exploration prospects in Q1 2012. See "Non-IFRS Measures" section within MD&A for reconciliation to adjusted funds from operations.

Financial Highlights for the Three Months Ended September 30, 2011

Canacol Energy Ltd. ("Canacol" or the "Corporation") completed a successful quarter in fiscal Q1 2012. Highlights include:

- Total revenues for the three months ended September 30, 2011 increased 110% to $35.3 million from $16.8 million for the comparable period.
- Funds from operations for the three months ended September 30, 2011 increased 129% to $17.8 million from $7.8 million for the comparable period. Adjusted funds from operations for the three months ended September 30, 2011 increased 150% to $19.5 million from $7.8 million for the comparable period.
- Net income for the three months ended September 30, 2011 was $13.5 million, compared to a loss of $30.1 million for the comparable period.
- Capital expenditures for the three months ended September 30, 2011 increased to $31.4 million.
- Average daily sales volumes increased 170% to 9,910 barrels of oil per day for the three months ended September 30, 2011 compared to 3,671 barrels of oil per day for the comparable period. The Corporation's current production is discussed below.
- For the three months ended September 30, 2011, the Corporation's operating netback for non-tariff (NRI) production was $55.17/bbl and for tariff production was $8.71/bbl.
- The Corporation's balance sheet remains strong with $115.5 million in cash, cash equivalents and restricted cash, and $85.1 million of working capital surplus at September 30, 2011.

OPERATIONAL UPDATE

Corporate Production

Corporate net production for the month of October 2011 averaged 11,809 bopd, which consisted of 3,115 bopd of non-tariff production and 8,694 bopd of tariff production. Corporate net production for November 2011 month to date was 14,238 bopd, which consisted of 4,792 bopd of non-tariff production and 9,446 bopd of tariff production.

On October 7, 2011 and November 5, 2011, respectively, the electro-submersible pumps in the Rancho Hermoso 7 ("RH 7") and 10 ("RH 10") wells failed, resulting in a gross total of 5,443 bopd (1,235 bopd net) of non-tariff production being shut in. A new ESP is currently being installed into the RH 10 well, which is expected to return to production the week of November 13, 2011. A new ESP will then be installed in the RH 7 well, which is expected to be placed back on production in the third week of November 2011. Once both wells have been brought back onto production, the Corporation anticipates a total of 1,235 bopd of net production being brought back online. The RH 7 well could not be repaired earlier as it is located on the same platform as the RH 12 well, which was being drilled during the month of October 2011.

Rancho Hermoso Field

Llanos Basin, Colombia

In mid-September 2011, the Corporation completed the drilling and casing of the Rancho Hermoso 11 ("RH 11") well, the first of four new development wells it plans to drill through the remainder of calendar 2011. The well was drilled to a total depth of 10,189 feet measured depth *("ft md")* in the Ubaque reservoir. Petrophysical analysis of the open-hole logs indicates a total of 130 ft of oil pay within 6 different reservoir intervals in the RH 11 well: 15 ft of oil pay within the C7 reservoir with average porosity of 21%, 13 ft of oil pay in the Mirador reservoir with average porosity of 25%, 12 ft of pay within the Los Cuervos–Barco reservoir with average porosity of 26%, 16 ft of oil pay within the Guadalupe reservoir with average porosity of 28%, 10 ft of oil pay within the Gacheta reservoir with average porosity of 20%, and 64 ft of oil pay within the Ubaque reservoir with average porosity of 25%. In October 2011, RH 11 was brought onto permanent production from the Ubaque reservoir.

Subsequent to September 30, 2011, the Corporation completed the drilling and casing of the Rancho Hermoso 12 ("RH 12") well, the second of its four well development program through the remainder of calendar 2011. The well was drilled to a total depth of 10,160 ft md in the Ubaque reservoir. Petrophysical analysis of the open-hole logs indicates a total of 130 ft of oil pay within 5 different reservoir intervals in the well: 13 ft of oil pay within the C7 reservoir with average porosity of 22%, 11 ft of oil pay in the Mirador reservoir with average porosity of 29%, 21 ft of pay within the Los Cuervos–Barco reservoir with average porosity of 20%, 40 ft of oil pay within the Guadalupe reservoir with average porosity of 23%, and 45 ft of oil pay within the Ubaque reservoir with average porosity of 25%. In November 2011, the well was perforated in the Los Cuervos – Barco interval and was placed on production at an initial gross rate of 14,709 bopd (3,697 bopd net).

For the remainder of calendar 2011, the Corporation anticipates drilling 2 additional development wells at its Rancho Hermoso field.

The Corporation has awarded the construction contract for its previously announced gas liquids separation facility at Rancho Hermoso, which is expected to be ready to receive gas and associated liquids in January 2012.

COR 11 and COR 39 Exploration and Production ("E&P") Contracts

Upper Magdalena Basin, Colombia

In September 2011, the Corporation entered into a definitive agreement with Sintana Energy Inc., the South American operations subsidiary of Drift Lake Resources Inc. (TSXV:DLA), to farm out 30% of its 100% operated working interest on the COR 11 and COR 39 E&P contracts. The Corporation was awarded a 100% operated working interest in the E&P contracts in February 2011 by the Agencia Nacional de Hidrocarburos ("ANH"). Under the terms of the definitive agreement, Sintana will pay 60% of the work commitment costs associated with the Phase 1 Exploration Phase for each of the contracts in order to earn a 30% working interest in each of the contracts. The Phase 1 work commitments for the COR 11 E&P contract include the acquisition of 155 kilometers of 2D seismic and the drilling of one exploration well. The Phase 1 commitments for the COR 39 E&P contract include the acquisition of 120 km of 2D seismic and the drilling of 2 exploration wells. The Phase 1 period for each of the contracts is 3 years in length, expiring in February 2014. The Corporation shall remain the operator of both of the E&P contracts.

COR 11 and COR 39 are located in the Guando trend of Colombia's Upper Magdalena Basin. Guando is one of the last 100 million barrel fields to be found in Colombia with some favorable world-class attributes that have not yet been adequately pursued in the trend. Guando field was discovered in 2000 and contains medium-gravity oil with a hydrocarbon column over 2,100 feet thick and a net reservoir over 1,000 feet thick. Recoverable reserve estimates are still increasing above 126 million barrels due to improved water flood programs. Representing approximately 272,000 gross acres, COR 11 and COR 39 are 60 kilometers apart on either side of the Guando field and are close to established infrastructure and local markets. In 2012, the Corporation anticipates acquiring 2D seismic on both the COR 11 and COR 39 E&P contracts.

Tamarin, Cedrela, Sangretoro E&P Contracts

Caguan-Putumayo Basin, Colombia

In late October 2011, the Corporation completed the drilling of the Tamarin 1 exploration well, the first of five exploration wells it plans to drill prior to mid-year 2012 in the Caguan-Putumayo Basin, Colombia. Tamarin 1 reached a total depth of 2,774 feet without incident. The primary Mirador sandstone reservoir was encountered with approximately 60 feet of porous sandstone, but was wet with only minor oil shows. The well was plugged and abandoned.

The Corporation plans to drill two exploration wells on its Cedrela E&P contract, followed by two additional wells on its Sangretoro E&P Contract, through to mid-year 2012.

The Corporation is operator of and has 100% working interest in the Cedrela and Sangretoro E&P contracts totaling 705,000 total net acres in this emerging heavy oil basin. Using recently acquired 2D seismic over the blocks, the Corporation has mapped a total of 20 structural and stratigraphic prospects and leads with an estimated 1.1 billion barrels of total net unrisked recoverable resources on the Cedrela and Sangretoro E&P contracts. The Corporation's seismic program for Sangretoro includes a total of 300 kilometers of 2D seismic, of which 149 kilometers has been shot and interpreted. The Corporation anticipates completing the seismic program by calendar year end 2011.

Corporate Acquisition

Subsequent to September 30, 2011, Canacol entered into a pre-acquisition agreement with a private company to acquire all of PrivateCo's common shares and other securities. The Corporation expects the transaction to close by mid-December 2011.

The transaction provides Canacol a suite of exploration assets located in the Llanos, Caguan, and Middle Magdalena basins of Colombia. Further, the acquisition will provide an estimated $14.5 million of additional working capital, before deduction of PrivateCo's expenditures on exploration commitments prior to closing, which are creditable against the working capital amount. Canacol expects to fund and execute PrivateCo's exploration program in calendar year 2012 with no material impact to its own existing production and exploration programs.

PrivateCo has interests in eight exploration and production blocks in Colombia governed by contracts under the ANH. These assets consist of four blocks in the Llanos basin (152,000 net acres), one block in the Caguan-Putumayo basin (103,000 net acres), and three blocks in the Middle Magdalena basin (138,000 net acres).

Under the terms of the Acquisition, each common share of PrivateCo will be exchanged for 0.86 common shares of Canacol. The purchase price per PrivateCo common share of C$0.58 per share was calculated based on the trailing five-day volume weighted-average price of the Corporation's common shares of C$0.67 per share. In aggregate, the Corporation expects to issue between 103.1 million and 106.0 million common shares to effect the transaction, which is dependent on the ultimate treatment of outstanding PrivateCo stock options and warrants, and assuming no working capital adjustment at closing.

In Canada, the offer is subject to regulatory and stock exchange approvals, including the approval of the Toronto Stock Exchange. In Colombia, the parties will comply with applicable regulatory notices and procedures.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. (the "Corporation") and its subsidiaries are primarily engaged in petroleum and natural gas exploration and development activities in Colombia, Brazil and Guyana. The Corporation's head office is located at 2110, 333 – 7th Avenue SW, Calgary, Alberta, T2P 2Z1, Canada. The Corporation's shares are traded on the Toronto Stock Exchange under the symbol CNE and the Bolsa de Valores de Colombia under the symbol CNE.C.

Advisories

The following management's discussion and analysis ("MD&A") is dated November 14, 2011 and is the Corporation's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Corporation's financial position. Comments relate to and should be read in conjunction with the unaudited interim condensed consolidated financial statements of the Corporation for the three months ended September 30, 2011 and 2010 (the "interim financial statements"), and the audited consolidated financial statements and management's discussion and analysis for the year ended June 30, 2011. In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Previously, the Corporation prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The interim financial statements have been prepared in accordance with IFRS and all amounts herein are in United States dollars, unless otherwise noted, and all tabular amounts are in thousands of United States dollars, except per share amounts or as otherwise noted. Additional information for the Corporation, including the annual information form, may be found on SEDAR at www.sedar.com.

Forward-Looking Statements – *Certain information set forth in this document contains forward-looking statements. All statements other than historical fact contained herein are forward-looking statements, including, without limitation, statements regarding the future financial position, business strategy, production rates, and plans and objectives of or involving the Corporation. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. In particular with respect to forward-looking comments in this MD&A, readers are cautioned that there can be no assurance that the Corporation will complete the PrivateCo acquisition as described herein, complete its planned capital projects on schedule, fund its gas liquids separation facility with a term debt facility, or that hydrocarbon-based royalties assessed will remain consistent or that royalties will continue to be applied on a sliding-scale basis as production increases on any one block. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom.*

In addition to historical information, this MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook"). These statements are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; and risks associated with oil and gas operations, many of which are beyond the control of the Corporation. Accordingly, there is no representation by the Corporation that actual results achieved during the forecast period will be the same in whole or in part as those forecasted. Except to the extent required by law, the Corporation assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are qualified in their entirety by these cautionary statements.

Readers are further cautioned not to place undue reliance on any forward-looking information or statements.

Non-IFRS Measures *– One of the benchmarks the Corporation uses to evaluate its performance is funds from operations. Funds from operations is a measure not defined in IFRS that is commonly used in the oil and gas industry. It represents cash provided by operating activities before changes in non-cash working capital and decommissioning obligation expenditures. In addition, the Corporation also uses adjusted funds from operations to adjust for income taxes payable on overlifted production which are recoverable in future periods, an issue specific to the Corporation (see detailed discussion below). The Corporation considers funds from operations and adjusted funds from operations key measures as they demonstrate the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Funds from operations and adjusted funds from operations should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation's determination of funds from operations and adjusted funds from operations may not be comparable to that reported by other companies. The Corporation also presents funds from operations and adjusted funds from operations per share, whereby per share amounts are calculated using weighted-average shares outstanding consistent with the calculation of earnings per share. The following table reconciles the Corporation's cash provided by operating activities to funds from operations and adjusted funds from operations:*

	Three months ended September 30, 2011	Three months ended September 30, 2010
Cash provided by operating activities	**$ 30,136**	$ 2,491
Changes in non-cash working capital	**(12,375)**	5,275
Funds from operations	**17,761**	7,766
Income taxes on overlifted volumes sold, recoverable in future periods (1)	**234**	-
Pre-license costs for exploration prospects (2)	**1,456**	-
Adjusted funds from operations	**$ 19,451**	$ 7,766

(1) See detailed discussion of overlifted volumes below under the heading "Unrealized Gain on Overlifted Volumes Payable".

(2) Pre-license costs are exploration related but cannot be capitalized under IFRS; they do not relate to existing operations.

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, including the current portion of any principal amount of convertible debentures, assuming they are out-of-the-money and not repayable in shares at maturity, and is used to evaluate the Corporation's financial leverage. Operating netback is a benchmark common in the oil and gas industry and is calculated as total crude oil sales, net of royalties, less operating and transportation expenses, calculated on a per barrel basis of sales volumes. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices. Working capital and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

IFRS

This reporting period is the Corporation's first under IFRS. As a result, the accounting policies of the Corporation have been adjusted to comply with IFRS beginning with the balance sheet as at July 1, 2010. A comprehensive summary of all of the significant changes, including reconciliations of Canadian GAAP financial statements to those prepared under IFRS, is presented in note 23 "Transition to IFRS" of the Corporation's interim financial statements as at and for the three months ended September 30, 2011.

The adoption of IFRS did not impact the cash the Corporation generated; however, it did have an impact on the Corporation's statement of financial position and statement of operations and comprehensive income (loss). A reconciliation of the previously reported net loss for the three months ended September 30, 2010, from Canadian GAAP to IFRS is provided below:

		Three months ended September 30, 2010
Net loss under Canadian GAAP, as previously reported	$	(2,602)
Depletion and depreciation		1,469
Deferred taxes		(30)
Net finance expense		(2,764)
Impairment loss on Brazilian assets		(11,742)
Loss on convertible debentures		(14,485)
Stock-based compensation		86
Net loss under IFRS	$	(30,068)

RESULTS OF OPERATIONS

Overview

The Corporation's primary producing property is the Rancho Hermoso field in Colombia. Production from Rancho Hermoso falls under either: i) "non-tariff", "net revenue interest" or "NRI" production, which represents crude oil produced under a production sharing contract with Ecopetrol S.A. ("Ecopetrol"), the state oil company of Colombia; or ii) "tariff" production, which represents crude oil produced under a risk service contract with Ecopetrol whereby the Corporation receives a set tariff price per barrel of oil produced. Tariff production is limited to one specific formation, the Mirador formation, while NRI production is derived from the remaining formations, including the Ubaque, Guadalupe, Barco Los Cuervos and Carbonera.

Tariff revenues relate to 100% of the gross sales of tariff oil and the Corporation reports gross tariff sales volumes in this MD&A. NRI revenues relate to only the Corporation's net revenue interest in such sales volumes, which are reported in this MD&A net after royalties. The production sharing contract for NRI oil requires the Corporation to pay 100% of the gross operating costs with respect to NRI production from the field. Consequently, when analyzing per barrel operating costs and operating netbacks, it is important for readers to understand that 100% of gross operating costs are being included in the numerator of this calculation, while only the Corporation's net revenue interest of sales volumes is used in the denominator. This makes comparison of operating costs per barrel and operating netbacks between tariff oil and NRI oil more difficult without considering gross sales volumes. Consequently, the Corporation has provided additional information with respect gross sales volumes for the Rancho Hermoso field to assist the reader with these metrics.

The Corporation also has minor production from its Capella and Entrerrios properties in Colombia as well as from its property in Brazil for Q1 2011, which was subsequently sold and is not included in Q1 2012 sales volumes. Sales volumes from these properties are reported in this MD&A net after royalties, the same as NRI oil.

In addition to its producing fields, the Corporation has significant interests in a number of exploration blocks in Colombia, Brazil and Guyana. A more detailed discussion of these blocks and the commitment related thereto is provided further below in this MD&A.

Average Daily Crude Oil Production and Sales Volumes – Barrels of Oil per Day ("bopd")

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Gross production (Rancho Hermoso only)			
Rancho Hermoso – tariff	**6,476**	1,259	414%
Rancho Hermoso – non-tariff	**13,187**	6,472	104%
	19,663	7,731	154%
Production, net after royalties			
Rancho Hermoso – tariff	**6,476**	1,259	414%
Rancho Hermoso – non-tariff (NRI)	**3,071**	1,519	102%
	9,547	2,778	244%
Other	**203**	210	(3%)
Production, net after royalties	**9,750**	2,988	226%
Inventory movements	**160**	683	(77%)
Sales, net after royalties	**9,910**	3,671	170%
Gross sales (Rancho Hermoso only)			
Rancho Hermoso – tariff	**6,458**	1,253	415%
Rancho Hermoso – non-tariff	**13,326**	7,172	86%
	19,784	8,425	135%
Sales, net after royalties			
Rancho Hermoso – tariff	**6,458**	1,253	415%
Rancho Hermoso – non-tariff (NRI)	**3,255**	2,219	47%
	9,713	3,472	180%
Other	**197**	199	(1%)
Sales, net after royalties	**9,910**	3,671	170%

The increase in production at Rancho Hermoso reflects the Corporation's continued success with its development drilling program, offset by natural production declines. This drilling program has resulted in the Corporation producing from 11 wells in Q1 2012 compared to 8 wells in Q1 2011.

Rancho Hermoso tariff production for Q1 2012 increased 414% compared to Q1 2011 primarily due to the successful drilling of RH-9, which came on production in December 2010 at an initial rate of approximately 6,500 bopd.

Rancho Hermoso NRI production increased 102% primarily due to the successful drilling of RH-7, RH-8 and RH-10, which came on production in October 2010, December 2010 and February 2011, respectively, at a combined initial rate of approximately 9,300 bopd.

The Corporation's producing assets in Brazil were sold effective July 2011.

Total net production for November 2011 month to date was 14,238 bopd, which consisted of 4,792 bopd of non-tariff production and 9,446 bopd of tariff production. On October 7, 2011 and November 5, 2011, respectively, the electro-submersible pumps in the RH 7 and RH 10 wells failed, resulting in a gross total of 5,443 bopd (1,235 bopd net) of non-tariff production being shut in. A new ESP is currently being installed into the RH 10 well, which is expected to return to production the week of November 13, 2011. A new ESP will then be installed in the RH 7 well, which is expected to be placed back on production in the third week of November 2011. Once both wells have been brought back onto production the Corporation anticipates a total of 1,235 bopd of net production being brought back online. The RH 7 well could not be repaired earlier as it is located on the same platform as the RH 12 well, which was being drilled during the month of October 2011.

Crude Oil Sales

		Three months ended September 30, 2011		Three months ended September 30, 2010	Change
Rancho Hermoso – tariff	$	8,877	$	1,579	462%
Rancho Hermoso – NRI		25,284		14,102	79%
		34,161		15,681	118%
Other		1,169		1,117	5%
Crude oil sales, net after royalties	$	35,330	$	16,798	110%

Crude oil sales are recorded net after royalties. The increase in crude oil sales from Q1 2011 to Q1 2012 is primarily the result of increased overall sales of 170%, offset by a decrease in overall average realized prices resulting from tariff production contributing a greater portion to the production mix. In Q1 2012, tariff sales represented 65% of total sales compared to only 34% in Q1 2011.

Average Benchmark and Realized Sales Prices

$/bbl		Three months ended September 30, 2011		Three months ended September 30, 2010	Change
West Texas Intermediate ("WTI")	$	89.77	$	76.06	18%
Rancho Hermoso – NRI	$	84.43	$	69.08	22%
Other		64.50		61.01	6%
Total NRI		83.29		68.41	22%
Rancho Hermoso – tariff		14.94		13.70	9%
Average realized sales price	$	38.75	$	49.74	(22%)

The Corporation's Rancho Hermoso NRI sales prices increased 22% in Q1 2012 compared to Q1 2011, slightly above the benchmark WTI price increases of 18%. Overall NRI sales prices also increased 22% to $83.29/bbl from $68.41/bbl, again slightly above the WTI increase of 18%. Tariff sales are based on contractual amounts. The increase in realized tariff sales is the result of an increase in the contractual amount the Corporation received for tariff sales in Q1 2012 compared to Q1 2011. The Corporation expects realized tariff prices to be $17.36/bbl for the period from September 1, 2011 until August 2018, when the contract expires.

Royalties

In Colombia, royalties are taken in kind generally at a rate of 8% until net field production reaches 5,000 bopd, then increases on a sliding scale to 20% up to field production of 125,000 bopd. The Corporation's average royalty on NRI production for Q1 2012 was 8%, compared to 8% for Q1 2011. There are no royalties on tariff production.

The Corporation records crude oil sales net of royalties.

Operating and Transportation Expenses

Total operating and transportation expenses for Q1 2012 compared to Q1 2011 were as follows:

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Operating expenses	$ 8,462	$ 6,297	34%
Transportation expenses	4,807	1,037	364%
	$ 13,269	$ 7,334	81%
$/bbl	$ 14.55	$ 21.72	(33%)

As described above, the Corporation's primary producing property is the Rancho Hermoso field in Colombia. Under its risk service contract with Ecopetrol, the Corporation receives a set tariff price per barrel of oil produced and sold from the Mirador formation. The Corporation incurs 100% of the operating expenses related to such production. Under its production sharing contract with Ecopetrol, the Corporation receives a net revenue interest in the production from the other formations at Rancho Hermoso and incurs 100% of the operating expenses related to such production. Since the total operating expenses incurred at Rancho Hermoso relate to 100% of the gross production from the field, the Corporation allocates operating expenses to tariff and NRI oil based on gross sales volumes. When stating NRI operating expenses on a per barrel basis, this results in a multiplier being applied of gross NRI sales divided by net NRI sales, after royalties. However, the gross operating expense per barrel to produce and sell a tariff barrel versus an NRI barrel remains the same.

An analysis of operating expenses is provided below:

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Rancho Hermoso			
Operating expenses	$ 7,725	$ 5,550	39%
Gross sales (Mbbls)	1,820	775	135%
$/bbl of gross sales	$ 4.24	$ 7.16	(41%)
Allocated to:			
Rancho Hermoso – tariff	$ 2,522	$ 825	206%
Rancho Hermoso – NRI	5,203	4,725	10%
	7,725	5,550	39%
Other	737	747	(1%)
Total operating expenses	$ 8,462	$ 6,297	34%
$/bbl			
Rancho Hermoso – tariff	$ 4.24	$ 7.16	(41%)
Rancho Hermoso – NRI	$ 17.46	$ 23.14	(25%)
Total operating expenses	$ 9.28	$ 18.64	(50%)

Total operating expenses have increased 34% in Q1 2012 compared to Q1 2011. The increase relates to the significant increase in sales volumes between the comparable periods of 170%. The sales volume increase relates entirely to increased production from the Rancho Hermoso field, the Corporation has been able to realize significant operating efficiencies from Q1 2011 to Q1 2012. As a result, operating expenses per barrel have decreased 41% on a gross basis at Rancho Hermoso from Q1 2011 to Q1 2012. These efficiencies translate down to the operating costs per barrel split for tariff and NRI production.

An analysis of transportation expenses is provided below:

		Three months ended September 30, 2011		Three months ended September 30, 2010	Change
Rancho Hermoso – tariff	$	1,185	$	148	701%
Rancho Hermoso – NRI		3,534		697	407%
Other		88		192	(54%)
Total transportation expenses	$	4,807	$	1,037	364%
$/bbl					
Rancho Hermoso – tariff	$	1.99	$	1.28	55%
Rancho Hermoso – NRI	$	11.80	$	3.41	246%
Total transportation expenses	$	5.27	$	3.07	72%

Transportation expenses have increased in Q1 2012 compared to Q1 2011 on a total and per barrel basis due to significantly increased sales volumes, higher trucking tariffs and increased average delivery distances.

Operating Netback

Total operating netback is heavily influenced by the sales volume split between tariff and NRI oil. Because tariff sales contributed a greater proportion to Q1 2012 sales volumes compared to Q1 2011, 65% in Q1 2012 versus 34% in Q1 2011, this has resulted in a reduction in total operating netback, even though tariff and NRI operating netbacks have each improved. Readers are cautioned that a comparison of total operating netback for the Corporation from one period to another is not meaningful if the ratio of tariff oil sales to NRI oil sales has materially changed, as is the case from Q1 2011 to Q1 2012. A more meaningful analysis is to examine operating netback by major production category, which is provided after the table below.

$/bbl		Three months ended September 30, 2011		Three months ended September 30, 2010	Change
Crude oil sales, net of royalties	$	38.75	$	49.74	(22%)
Operating and transportation expenses		(14.55)		(21.72)	(33%)
Operating netback (see note to reader above)	$	24.20	$	28.02	(14%)

Operating netback by major production category is as follows:

$/bbl		Three months ended September 30, 2011		Three months ended September 30, 2010	Change
Rancho Hermoso – tariff oil					
Tariff revenue	$	14.94	$	13.70	9%
Operating and transportation expenses		(6.23)		(8.44)	(26%)
Operating netback	$	8.71	$	5.26	66%
Rancho Hermoso – NRI oil					
Crude oil sales, net of royalties	$	84.43	$	69.08	22%
Operating and transportation expenses		(29.26)		(26.55)	10%
Operating netback	$	55.17	$	42.53	30%

General and Administrative Expenses

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Gross costs	$ 3,975	$ 2,850	39%
Less: capitalized amounts	(1,434)	-	n/a
General and administrative expenses	$ 2,541	$ 2,850	(11%)
$/bbl	2.79	8.44	(67%)

Gross general and administrative expenses increased 39% in Q1 2012 compared to Q1 2011 primarily due to an increase in the number of staff to support operations in Colombia.

Net Finance (Income) Expense

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Interest income on bank deposits	$ (535)	$ (251)	113%
Net commodity contract (gains) losses – realized	79	-	n/a
Net commodity contract (gains) losses – unrealized	(616)	443	n/a
Net foreign exchange (gain) loss	(5,045)	1,195	n/a
Accretion on equity tax payable	26	-	n/a
Accretion of decommissioning obligations	144	258	(44%)
Interest expense	262	2,018	(87%)
Net finance (income) expense	$ (5,685)	$ 3,663	n/a

Interest – Interest income increased in Q1 2012 compared to Q1 2011 due to interest earned on higher cash balances. Interest expense decreased in Q1 2012 compared to Q1 2011 due to a combination of lower convertible debenture debt levels and capitalization of borrowing costs.

Foreign exchange gain – The Corporation is primarily exposed to foreign exchange gains and losses in Colombia and Canada.

Commodity contracts – The Corporation enters into derivative risk management contracts in order to ensure a certain level of cash flows to fund planned capital projects. At September 30, 2011, the Corporation had financial WTI oil collars outstanding under the following terms:

Period	Volume	Type	Price Range
Nov 2010 – Oct 2011	500 bbls/day	Financial WTI Oil Collar	$70.00 – $100.00
Dec 2010 – Nov 2011	500 bbls/day	Financial WTI Oil Collar	$70.00 – $100.00

Stock-Based Compensation Expense

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Gross costs	$ 3,570	$ 2,902	23%
Less: capitalized amounts	(1,092)	-	n/a
Stock-based compensation expense	$ 2,478	$ 2,902	(15%)

Stock-based compensation expense is a non-cash expense that is based on the fair value of stock options and restricted share units granted. The fair value is calculated on grant date and amortized over the vesting period.

Depletion, Depreciation and Amortization Expense

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Depletion, depreciation and amortization expense	**$ 8,523**	$ 4,583	86%
$/bbl	**9.35**	13.57	(31%)

Total depletion, depreciation and amortization costs per barrel decreased in Q1 2012 as compared to Q1 2011 as a result of positive reserve revisions at June 30, 2011 which affected the calculation for Q1 2012. Under IFRS, the Corporation depletes its assets on a component basis utilizing total proved plus probable reserves as opposed to depleting it assets using total proved reserves under Canadian GAAP.

Unrealized Gain on Overlifted Volumes Payable

Under a participation contract with Ecopetrol, the Corporation is required to deliver Ecopetrol's share of crude oil production volumes in kind at a particular delivery point. However, due to capacity restrictions at this delivery point, Ecopetrol typically takes delivery of its production volumes at the field. At times, Ecopetrol is not able to take delivery of all of its production volumes in kind and the Corporation is required to sell such production since sufficient on-site storage facilities are not available. When the Corporation sells these "overlifted" volumes, a liability is recorded for the amount of the sale and prepaid transportation is recorded for associated transportation costs. As overlifted volumes are delivered to Ecopetrol, the liability and prepaid transportation amounts are reduced with corresponding recognition of such amounts as revenue and transportation costs. Since the participation contract with Ecopetrol requires delivery of production volumes in kind, the Corporation revalues the liability at each period-end to reflect the fair value of the crude oil owing to Ecopetrol at that time; gains or losses related to such are recognized in profit or loss in the period. For Q1 2012, the Corporation recorded an unrealized gain on overlifted volumes payable of $7.1 million (Q1 2011 – $nil) as a result of the decrease in the average price per barrel of the liability from $103.69/bbl at June 30, 2011 to $82.34/bbl at September 30, 2011. The Corporation is currently discussing with Ecopetrol to repay the overlifted volumes liability and to minimize its impact in future periods.

The Corporation increased the overlifted volumes it sold under its participation contract with Ecopetrol in Q1 2012. The Corporation is required to pay current period income taxes based on total volumes sold, rather than only the volumes to which it is entitled. Further, a tax deduction for the cost of the oil is not available for the liability provision until such overlifted volumes are returned in kind or repaid in cash. As a result, the Corporation has recorded additional current tax expense of $234,000 related to such volumes, with a related deferred income tax recovery for the tax deduction available in future periods. Although this treatment has no impact on net income (loss), cash provided by operating activities and funds from operations are affected. In the opinion of management, this treatment does not adequately reflect the ongoing operations of the Corporation and management has provided a reconciliation of funds from operations to adjusted funds from operations for this item (refer to "Non-IFRS Measures" above).

Income Tax Expense

	Three months ended September 30, 2011	Three months ended September 30, 2010
Current income tax expense	**$ 3,915**	$ (168)
Deferred income tax expense (recovery)	**2,760**	(525)
Income taxes	**$ 6,675**	$ (693)

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 33%. Tax expense increased significantly due to the increase in taxable net income in Q1 2012 resulting from higher sales volumes and prices compared to Q1 2011.

Cash and Funds from Operations and Net Income (Loss)

	Three months ended September 30, 2011	Three months ended September 30, 2010	Change
Cash provided by operating activities	$ 30,136	$ 2,491	1,110%
Funds from operations	17,761	7,766	129%
Per share – basic and diluted ($)	0.03	0.02	50%
Adjusted funds from operations	19,451	7,766	150%
Per share – basic and diluted ($)	0.04	0.02	100%
Net income (loss)	13,486	(30,068)	n/a
Per share – basic and diluted ($)	0.03	(0.07)	n/a

Funds flow and adjusted funds flow from operations increased in Q1 2012 compared to Q1 2011 primarily due to increases in sales volumes, and higher operating netbacks.

Capital Expenditures

	Three months ended September 30, 2011	Three months ended September 30, 2010
Drilling and completions	$ 15,195	$ 7,834
Facilities and infrastructure	9,104	352
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other	7,057	55
Total capital expenditures	$ 31,356	$ 8,241
Recorded as:		
Expenditures on exploration and evaluation assets	$ 6,723	$ -
Expenditures on property, plant and equipment	$ 24,633	$ 8,241

Capital expenditures in Q1 2012 primarily relate to:

- RH 11 drilling and completion costs at the Rancho Hermoso field as well as a stratigraphic well at Tamarin;
- Costs related to the expansion of Rancho Hermoso facilities; and
- Seismic costs relate to the acquisition of 250 square kilometres of 2D seismic at Cedrela and 300 square kilometres of 2D seismic at Sangretoro.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

Based on the Corporation's financial position and liquidity at September 30, 2011 and projected future cash flows, management expects to be able to fund its working capital and capital project needs, and meet its other obligations, including servicing interest on its convertible debentures through the end of calendar 2012. At September 30, 2011, the Corporation had cash and cash equivalents of $109.0 million and working capital of $85.1 million. The Corporation believes it is well positioned financially with significant available credit capacity, assets that are providing strong production growth and operating netbacks, along with an extensive inventory of exploration prospects. The Corporation's assets provide significant funds from operations and are its largest source of liquidity. The Corporation has a history of generating positive funds from operations.

Credit Facilities and Debt

At September 30, 2011, the Corporation had revolving lines of credit in place in Colombia with an aggregate borrowing base of $40 million (COP$ 75.2 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. At September 30, 2011, no amounts were drawn under the facilities.

At September 30, 2011, the Corporation had letters of credit outstanding totalling $11.5 million to guarantee work commitments on exploration blocks. The total of these letters of credit reduce the amount available under the revolving lines of credit described above.

The Corporation has convertible debentures outstanding with a face value of $24.6 million (fair value – $24.3 million) that mature on July, 2015, and bear an annual coupon rate of 8%, payable semi-annually. The debentures are convertible into common shares of the Corporation at the option of the holder at a conversion price of C$1.0526 per share.

Share Capital

The aggregate number of common shares, stock options, and restricted share units outstanding at November 14, 2011 was approximately 555,108,000 (common shares – 513,066,000 , stock options – 41,662,000, restricted share units – 380,000).

Contractual Obligations

The following table provides a summary of the Corporation's cash requirements to meet its financial liabilities and contractual obligations existing at September 30, 2011:

	Less than 1 year	1-3 years	Thereafter	Total
Trade and other payables	18,166	-	-	18,166
Overlifted volumes payable	31,856	-	-	31,856
Equity tax payable	1,152	2,302	-	3,454
Income tax payable	20,245	-	-	20,245
Convertible debentures – principal	-	-	24,563	24,563
Convertible debentures – interest	2,027	4,054	1,689	7,770
Exploration contracts (see below)	53,800	6,750	-	60,550
Pipeline investment	4,316	-	-	4,316
Office lease	722	1,864	2,030	4,616
	132,284	14,970	28,282	175,536

Exploration Contracts

The Corporation has entered into a number of exploration and production contracts in Colombia, Brazil and Guyana which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding commitments at September 30, 2011 of $60.6 million and has issued $17.6 million in financial guarantees, $11.5 million of which are secured under the Corporation's credit facilities through letters of credit and the remainder is held in trust and recorded as restricted cash.

A summary of the Corporation's work program commitments is presented below.

Colombia

The Corporation has net work program and farm-in commitments totalling approximately $50.6 million, of which $43.8 million are due within a year. These commitments are planned to be satisfied by means of seismic and exploration drilling.

Basin	Commitment Date	Block	Net Acreage	Working Interest	Phase	Work Program Commitments
			(000 acres)			
Upper Magdalena	February 17, 2014	COR-11	124	70% (1)	1	155 kms of 2D seismic and 1 exploration well
Upper Magdalena	February 17, 2014	COR-39	67	70% (1)	1	120 kms of 2D seismic and 2 exploration wells
Putumayo	February 14, 2014	Anadaquies	41	36%	1	3D seismic and 2 exploration wells
Putumayo	February 28, 2010 (block under suspension)	Coati	25	40%	5	3D seismic and 1 exploration wells
Putumayo – Caguan	August 31, 2012	Sangretoro	385	100%	1	300 kms of 2D seismic
Putumayo – Caguan	June 29, 2012	Cedrela	320	100%	1	250 kms of 2D seismic

(1) The Corporation completed a farm-out of the COR-11 and COR-39 blocks in September 2011 whereby the farmee has agreed to pay 60% of the phase 1 work program commitments on each block.

Brazil

The Corporation has net work program commitments totalling approximately $5.0 million due within a year, all on blocks 169 and 170 of the Reconcavo basin. These commitments are planned to be satisfied through a combination of the execution of an exploration drilling program and through financial settlement of work commitments.

Guyana

The Corporation has net work program commitments totalling approximately $5.0 million due within a year. The operator is currently in discussions with the Guyanese government to extend the current exploration phase to May 2012 in order to drill the second commitment well.

Gas Purchases and Gas Plant

On August 31, 2011, the Corporation was awarded a contract by Ecopetrol to purchase produced natural gas from the Rancho Hermoso field at a fixed price of $6.50/MMbtu, which includes the associated liquids – naphtha, propane and butane. The contract is effective on January 1, 2012 and is for a period of 5 years. Subsequent to September 30, 2011, the Corporation initiated the construction of a gas liquids separation facility with the intention of processing the future natural gas production and selling the resulting liquids. The gas plant construction has been awarded and is expected to cost $28.4 million, all due within a year. The Corporation expects to fund the construction of the gas plant through a corporate term loan, which it is currently negotiating. The facility is expected to be ready to receive gas and associated liquids in January 2012.

Trucking Contract

The Corporation has signed an agreement with a Colombian trucking company for the exclusive use of 100 trucks for transportation of crude oil from the Corporation's operations in Colombia for a period of 3 years. The Corporation will pay transportation fees plus an additional 7.5% for administrative costs. Any excess of the fees charged over the actual operating costs will be shared equally between the Corporation and the trucking company at the end of each year. The Corporation has the option to purchase up to 50 trucks at the end of the 3 year agreement.

SUBSEQUENT EVENT

On November 9, 2011, The Corporation entered into a pre-acquisition agreement with a private Colombian exploration company ("PrivateCo") to acquire all of PrivateCo's common shares and other securities (the "Acquisition"). Under the terms of the Acquisition, each common share of PrivateCo will be exchanged for 0.86 common shares of the Corporation. The purchase price per PrivateCo common share of C$0.58 per share was calculated based on the trailing five-day volume weighted-average price of the Corporation's common shares of C$0.67 per share. PrivateCo's working capital is estimated at $14.5 million, before deduction of PrivateCo's expenditures on exploration commitments prior to closing, which are creditable against the working capital amount. In aggregate, the Corporation expects to issue between 103.1 million and 106.0 million common shares to effect the Acquisition, which is dependent on the ultimate treatment of outstanding PrivateCo stock options and warrants, and assuming no working capital adjustment at closing.

The Acquisition is subject to certain conditions and regulatory approvals. The Corporation expects the Acquisition to close by mid-December 2011.

OUTLOOK

In the Llanos Basin, the Corporation anticipates drilling 2 additional development wells at its Rancho Hermoso field in calendar 2011. In the Caguan-Putumayo basin, the Corporation and partner Sinochem will continue to emphasize appraisal and horizontal development wells at the Capella field. For higher impact exploration opportunities, the Corporation plans to drill one stratigraphic well and two explorations wells on its Cedrela and Andaquies E&P contracts, respectively. The Corporation is operator of and has a 100% working interest in Cedrela. The Corporation has a 36% working interest in the C&C Energia-operated, Andaquies E&P contract.

The Corporation will continue to invest in its future with plans to acquire 151 kilometres of 2D seismic at Sangretoro and the construction of a gas and liquids separation facility at its Rancho Hermoso field.

SUMMARY OF QUARTERLY RESULTS

	IFRS					Canadian GAAP		
	2012	2011				2010		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial								
Crude oil sales	**26,453**	37,339	23,452	15,669	15,219	5,330	4,992	2,648
Tariff revenue	**8,877**	9,676	8,677	1,212	1,579	1,874	1,607	1,611
Total revenues	**35,330**	47,015	32,129	16,881	16,798	7,204	6,599	4,259
Funds from operations (1)	**17,761**	11,200	18,024	1,829	7,766	(1,443)	(1,161)	(1,702)
Per share – basic and diluted ($)	**0.03**	0.02	0.04	-	0.02	-	-	-
Net income (loss)	**13,486**	19,625	(2,069)	(14,918)	(30,068)	(11,048)	(5,130)	(4,157)
Per share – basic and diluted ($)	**0.03**	0.04	-	(0.03)	(0.07)	(0.02)	(0.01)	(0.01)
Capital expenditures	**31,356**	24,824	20,665	22,403	8,241	6,089	4,122	8,520
Operations								
Tariff oil production (bopd)	**6,476**	7,568	6,870	980	1,259	1,152	1,549	1,651
NRI oil production (bopd)	**3,274**	3,880	3,001	2,650	1,729	1,559	858	418
Total oil production (bopd)	**9,750**	11,448	9,871	3,630	2,988	2,711	2,407	2,069

(1) Non-IFRS measure. See "Non-IFRS Measures" section. Includes $1.5 million of pre-license costs for exploration prospects in Q1 2012. See "Non-IFRS Measures" section within MD&A for reconciliation to adjusted funds from operations.

RISKS AND UNCERTAINTIES

There have been no significant changes in the three months ended September 30, 2011 to the risks and uncertainties as identified in the MD&A for the year ended June 30, 2011.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgments, assumptions and estimates in the preparation of the interim consolidated financial statements. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and the Corporation's significant accounting policies can be found in the notes to the interim financial statements. The following discussion highlights significant changes to critical accounting policies and estimates from those disclosed in the Corporation's MD&A for the year ended June 30, 2011 as a result of the adoption of IFRS.

Exploration and evaluation assets – The decision regarding technical feasibility and commercial viability of exploration and evaluation assets involves a number of assumptions, such as estimated reserves, commodity price forecasts, expected production volumes and discount rates, all of which are subject to material changes in the future.

Opening statement of financial position – On transition to IFRS, the Corporation's full cost pool under Canadian GAAP was allocated to IFRS areas based on estimated proved plus probable reserve volumes. The estimate of proved plus probable reserve volumes required a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. The resulting fair value estimates may not necessarily be indicative of the amounts that may be realized or settled in a current market transaction, nor do they represent costs historically spent.

Reserve estimates – Under IFRS, estimates of reserves at the area level, rather than the country cost centre level, can have a significant impact on profit or loss, as they are a key component in the calculation of DD&A. A downward revision in the estimate of reserve quantities could result in a higher DD&A charge to profit or loss. Furthermore, DD&A is calculated used proved plus probable reserve estimates.

Reserve estimates can have a significant impact on profit or loss and the carrying value of capital assets. The process of estimating reserves requires significant judgement based on available geological, geophysical, engineering, and economic data, projected rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to interpretation and uncertainty. Reserve estimates impact profit or loss through depletion expense and the application of impairment tests. Revisions or changes in reserve estimates can have either a positive or a negative impact on profit or loss and can impact the carrying amount of capital assets.

Creditors also use reserve estimates to assess the allowable borrowing base under secured credit facilities. Although the Corporation currently does not have any reserve-based debt facilities, changes to reserve estimates can result in borrowing base increases or decreases, which could impact the Corporation's ability to access such debt facilities.

Asset impairments – For impairment testing, the assessment of facts and circumstances is a subjective process that often involves a number of estimates and is subject to interpretation. Also, the testing of assets or Cash Generating Units ("CGU") for impairment, as well as the assessment of potential impairment reversals, requires estimates of an asset's or CGU's recoverable amount. The estimate of a recoverable amount requires a number of assumptions and estimates, including quantities of reserves, expected production volumes, future commodity prices, discount rates as well as future development and operating costs. These assumptions and estimates are subject to change as new information becomes available and changes in any of the assumptions, such as a downward revision in reserves, a decrease in commodity prices or an increase in costs, could result in an impairment of an asset's or CGU's carrying value.

Deferred income taxes – The Corporation recognizes a deferred income tax liability based on estimates of temporary differences between the book and tax value of its assets, liabilities, and tax pool pools. An estimate is also used for both the timing and tax rate upon reversal of the temporary differences, and for any potential future disputes on tax filings. Actual differences and the timing of reversals may differ from estimates, impacting the deferred income tax balance and profit or loss.

Contingencies – In the normal course of operations, the Corporation has disputes with industry participants for which the Corporation currently cannot determine the ultimate result. The Corporation records costs as they are incurred or become determinable. Management believes the resolution of these matters would not have a material adverse effect on the Corporation's consolidated financial position or its results from operations.

CHANGES IN ACCOUNTING POLICIES

The Corporation is currently reviewing a number of new and revised IFRSs that have been issued but are not yet effective. A detailed discussion of new accounting policies that may affect the Corporation is provided in the interim condensed consolidated financial statements for the three months ended September 30, 2011.

REGULATORY POLICIES

Certification of Disclosures in Interim Filings

Subsequent to the listing of the Corporation's stock on the Toronto Stock Exchange and the transition of the Corporation from a venture issuer to a non-venture issuer, effective May 3, 2011, and in preparation for its full interim certification requirements as of September 30, 2011, management has continued the process of documenting and assessing the design of its disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICFR").

Disclosure Controls and Procedures

DC&P are designed to provide reasonable assurance that all relevant information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure. The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), along with other members of management, have designed, or caused to be designed, under the CEO and CFO's supervision, disclosure controls and procedures and established processes to ensure that they are provided with sufficient knowledge to support the representations made in the interim certificates required to be filed under National Instrument 52-109. In addition to the processes that specifically fall into the category of DC&P, the Corporation has also adopted a company-wide Corporate Disclosure Policy and has additional procedures in place to provide reasonable assurance that any material information required to be disclosed by the Corporation in its interim filing is recorded, processed, summarized and reported within the time periods specified in securities legislation.

Internal Controls over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate internal control over financial reporting to provide reasonable assurance regarding the reliability of financial statements prepared in accordance with IFRS. With the assistance of expert advisors, the Corporation's CEO and CFO evaluated the design and operational effectiveness of the Corporation's ICFR for the interim quarter using the framework and criteria established in Internal Control – Integrated Framework ("COSO Framework") published by The Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). The Corporation's certifying officers did not identify any material weaknesses relating to the design of the Corporation's ICFR framework.

During the three months ended September 30, 2011, there has been no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Limitations of Controls and Procedures

The Corporation's management, including its CEO and CFO, believe that any DC&P or ICFR, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, they cannot provide absolute assurance that all control issues and instances of fraud, if any, within the Corporation have been prevented or detected. These inherent limitations include the realities that judgements in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Accordingly, because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and not be detected. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. The Corporation has worked on improving the documentation and effectiveness of its DC&P and ICFR and will continue to do so in the future.