CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE AND SIX MONTHS ENDED DECEMBER 31, 2012

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Petroleum and natural gas revenues, net of royalties	**27,350**	55,241	(50%)	**69,145**	90,571	(24%)
Funds from operations (1) (2)	**2,943**	24,480	(88%)	**17,034**	42,241	(60%)
Per share – basic ($)	**0.05**	0.45	(90%)	**0.27**	0.80	(66%)
Per share – diluted ($)	**0.05**	0.45	(90%)	**0.27**	0.78	(65%)
Net income (loss) (2)	**3,131**	(2,423)	n/a	**(3,083)**	11,063	n/a
Per share – basic ($)	**0.05**	(0.04)	n/a	**(0.05)**	0.21	n/a
Per share – diluted ($)	**0.05**	(0.04)	n/a	**(0.05)**	0.20	n/a
Capital expenditures, excluding business acquisition	**22,667**	62,425	(64%)	**41,598**	93,781	(56%)

	December 31, 2012	June 30, 2012	Change
Cash and cash equivalents	**33,253**	30,789	8%
Restricted cash	**19,298**	6,555	194%
Working capital surplus, excluding the current portion of bank debt and derivatives (1)	**52,042**	29,697	75%
Short-term and long-term bank debt	**99,440**	27,986	255%
Total assets	**595,051**	406,828	46%
Common shares, end of period (000s)	**86,499**	61,898	40%

Operating	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Petroleum and natural gas production, before royalties (boepd)						
Petroleum	**5,035**	13,837	(64%)	**5,527**	11,935	(54%)
Natural gas	**319**	-	n/a	**160**	-	n/a
Total	**5,354**	13,837	(61%)	**5,687**	11,935	(52%)
Petroleum and natural gas sales, before royalties (boepd)						
Petroleum	**4,815**	14,155	(66%)	**6,068**	12,182	(50%)
Natural gas	**319**	-	n/a	**160**	-	n/a
Total	**5,134**	14,155	(64%)	**6,228**	12,182	(49%)
Realized sales prices ($/boe)						
Rancho Hermoso – non-tariff	**89.64**	99.34	(10%)	**91.23**	94.42	(3%)
Rancho Hermoso – tariff	**17.36**	17.36	-	**17.36**	16.35	6%
LLA 23	**88.54**	-	n/a	**88.54**	-	n/a
Esperanza	**33.87**	-	n/a	**33.87**	-	n/a
Ecuador – tariff	**39.53**	-	n/a	**39.53**	-	n/a
Total	**62.44**	47.10	33%	**65.27**	44.59	46%
Operating netbacks ($/boe) (1)						
Rancho Hermoso – non-tariff	**23.20**	53.06	(56%)	**30.60**	52.14	(41%)
Rancho Hermoso – tariff	**3.73**	10.06	(63%)	**5.11**	9.49	(46%)
LLA 23	**59.63**	-	n/a	**59.63**	-	n/a
Esperanza	**28.35**	-	n/a	**28.35**	-	n/a
Ecuador – tariff	**39.53**	-	n/a	**39.53**	-	n/a
Total	**19.01**	24.32	(22%)	**21.86**	23.97	(9%)

(1) Non-IFRS measure. See "Non-IFRS Measures" section within MD&A.
(2) Effective December 20, 2012, the Corporation completed a 10:1 consolidation of its common shares. Consequently, per share information presented above was restated to a post-consolidation basis for comparability.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. ("Canacol" or the "Corporation") and its subsidiaries are primarily engaged in petroleum and natural gas exploration and development activities in Colombia, Ecuador, Brazil, Guyana and Peru. The Corporation's head office is located at 4500, 525 - 8th Avenue SW, Calgary, Alberta, T2P 1G1, 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 CNEC.

Advisories

The following management's discussion and analysis ("MD&A") is dated February 11, 2013 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 and six months ended December 31, 2012 and 2011 (the "financial statements"), and the audited consolidated financial statements and management's discussion and analysis for the year ended June 30, 2012. The financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", 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 its planned capital projects on schedule, that additional natural gas sales contracts will be secured, that refinancing existing debt facilities or securing new debt facilities will be completed, 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; fluctuations 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 International Financial Reporting Standards ("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. The Corporation considers funds from operations a key measure as it demonstrates 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 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 may not be comparable to that reported by other companies. The Corporation also presents 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:

	Three months ended December 31,		Six months ended December 31,	
	2012	2011	**2012**	2011
Cash provided by operating activities	**$ 4,617**	$ 35,758	**$ 15,021**	$ 65,894
Changes in non-cash working capital	**(1,674)**	(11,278)	**2,013**	(23,653)
Funds from operations	**$ 2,943**	$ 24,480	**$ 17,034**	$ 42,241

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, excluding the current portion of commodity contracts and the current portion of any embedded derivatives asset/liability, 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 petroleum and natural gas sales, less royalties, less production and transportation expenses, calculated on a per barrel equivalent ("boe") basis of sales volumes using a conversion. 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.

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet of natural gas to barrels of oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A we have expressed boe using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Ministry of Mines and Energy of Colombia.

CONSOLIDATION OF COMMON SHARES

Effective December 20, 2012, the Corporation completed a 10:1 consolidation of its common shares. The share consolidation was effected prior to the issuance of common shares for the acquisition of Shona Energy Company, Inc. ("Shona"), described below.

BUSINESS COMBINATION

On October 15, 2012, the Corporation entered into an agreement (the "Arrangement Agreement") whereby the Corporation agreed to acquire 100% of the issued and outstanding class "A" common shares ("Shona Common Shares") and series "A" preferred shares ("Shona Preferred Shares") of Shona, in exchange for common shares of the Corporation ("Canacol Shares") and cash, by way of a statutory plan of arrangement (the "Arrangement"). On December 21, 2012, the closing date of the transaction, the Corporation acquired 100% of the issued and outstanding Shona Common Shares in exchange for 0.10573 Canacol Shares and C$0.0896 cash for each Shona Common Share (the "Consideration") and 100% of the issued and outstanding Shona Preferred Shares in exchange for $100.00 cash for each Shona Preferred Share. Canacol issued an aggregate of 24,600,758 Canacol Shares to Shona Common Shareholders in connection with the Arrangement.

Shona was an international oil and gas exploration and production company with operations focused in Colombia and Peru. With working interests in five blocks, Shona had net proven and probable reserves of approximately 95 billion cubic feet, or 16.6 million boe, at December 31, 2011 and operated production for the three months ended December 31, 2012 of approximately 15.6 million cubic feet per day, or 2,744 boepd, before royalties, from the Esperanza field in Colombia.

The strategic rationale of the acquisition of Shona included:

1) Doubling of the Corporation's 2P reserves plus deemed volumes to 34 million boe with a before-tax NPV10 of $736 million.
2) Adding long reserve life gas fields to the Corporation's existing portfolio of oil reserves.
3) Adding significant production under long-term sales contracts with escalating pricing. The Corporation also has the ability to raise gas production volumes in the short term with no material additional capital required.
4) Adding interests in five exploration assets with net risked prospective resources of 66 million barrels of oil and gas. Three of these assets are located adjacent to the Corporation's Capella heavy oil field situated in the Caguan-Putumayo Basin of Colombia.

Under the terms of the Arrangement Agreement, all of Shona's outstanding options were surrendered and terminated prior to closing of the Arrangement. In addition, all holders of Shona warrants were entitled to receive, in lieu of the number of Shona Common Shares otherwise issuable upon the exercise thereof, the number of Canacol Shares adjusted for an exchange ratio of 0.12587 of a Canacol Share per Shona Share and the exercise price of the warrants was reduced with respect to the exchange ratio of 0.12587 such that the warrants maintained their economic equivalency.

Acquisition related costs, other than share issue costs, of approximately $0.2 million have been expensed as period costs in the interim condensed consolidated statement of operations for the three and six months ended December 31, 2012.

From the period from December 21, 2012 to December 31, 2012, the acquired business contributed revenues, net of royalties, of $0.9 million and operating income of $0.8 million to Canacol's operations. If the acquisition had occurred on July 1, 2012, management estimates its pro forma revenues for Shona, net of royalties and operating income would have been approximately $14.7 million and $3.9 million, respectively, for the six months ended December 31, 2012. Operating income includes $4.9 million of transaction and other costs related to the acquisition by Canacol. It is impracticable to derive all amounts necessary to determine contributed net income from the acquired business as operations were immediately merged with Canacol's operations to realize synergies.

The acquisition has been accounted for using the purchase method with the results of Shona's operations included in the Corporation's financial and operating results commencing December 21, 2012. The allocation of net assets acquired was based on the best available information at the time and may be subject to further change. The allocation of the purchase price based on estimated fair values was as follows:

Consideration:		
Issue of common shares	$	68,346
Issue of warrants		2,231
Cash paid to common and preferred shareholders		40,224
	$	**110,801**
Net assets acquired:		
Cash	$	8,300
Restricted cash		2,327
Trade and other receivables		5,337
Other current assets		1,183
Exploration and evaluation assets		6,544
Property, plant and equipment		174,408
Trade and other payables		(5,002)
Other current liabilities		(683)
Decommissioning obligations		(1,961)
Deferred tax liability		(51,244)
Other long term liabilities		(261)
		138,948
Gain on business acquisition		(28,147)
	$	**110,801**

The gain on business acquisition was recognized as a result of the change in the Corporation's share price between when the Arrangement Agreement was signed and the closing of the acquisition.

RESULTS OF OPERATIONS

Overview

For the three and six months ended December 31, 2012, the Corporation's production primarily consisted of crude oil and natural gas liquids from its Rancho Hermoso field in the Llanos Basin of Colombia. Crude oil production from Rancho Hermoso falls under either: i) "non-tariff", 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 non-tariff production is derived from the remaining formations, including the Ubaque, Guadalupe, Barco Los Cuervos, Carbonera and Gacheta. Natural gas liquids production includes naphtha and LPGs from the processing of associated gas from the Rancho Hermoso field. The Corporation is responsible for 100% of the production expenses of the field, although it only recognizes non-tariff production before royalties of approximately 24-25% of gross non-tariff production. Over the second half of calendar 2012, the Corporation focused its efforts in Rancho Hermoso on higher netback non-tariff production versus low netback tariff production, which previously contributed a large percentage to the Corporation's total production. This trend has continued into calendar 2013 and all remaining tariff production has been converted to non-tariff formations as of the date hereof after the last remaining producing well experienced a recent mechanical issue and was converted to non-tariff production from the Barco reservoir, which is currently producing 2,198 gross bopd (540 bopd net) with 21 percent water cut and 900 Mscfpd of associated gas. Overall production at the Rancho Hermoso field has now stabilized and consists entirely of higher netback non-tariff oil production. The Corporation is currently working over the RH 17 well to convert it from a high water cut Mirador producer to a higher netback Ubaque producer, and has plans to sequentially recomplete an additional 3 high water cut producers to lower water cut producers in the first half of calendar 2013.

With the completion of the Shona acquisition described above, the Corporation added a significant natural gas production asset to its portfolio. The Esperanza field, located in the Lower Magdelana Basin of Colombia, produces dry natural gas for sale to local customers under long-term contracts. Significantly, the Corporation also has the ability to increase gas production volumes in the short term with no material additional capital required once additional sales contracts are secured. Effective February 8, 2013, the Corporation has executed an additional sales contract with a current buyer to formally increase contract volumes by approximately 5 MMcfpd (877 boepd) effective April 1, 2013. Since the acquisition of Shona was completed on December 21, 2012, the Esperanza field accounted for only a minor amount of the Corporation's total production for the three and six months ended December 31, 2012.

During the three months ended December 31, 2012, the Corporation made a key light oil discovery on the LLA 23 block, immediately adjacent to the Rancho Hermoso field. The initial well was completed and put onto production in early December 2012. As a result, the LLA 23 field accounted for only a minor amount of the Corporation's total production for the three and six months ended December 31, 2012. The Corporation plans to drill up to 3 development wells into the discovery commencing in mid-March 2013 and has recently received the necessary environmental approvals for such.

For the three and six months ended December 31, 2012, the Corporation also had minor crude oil production from its Capella and Entrerrios properties in Colombia. Capella, in particular, was shut-for the majority of the time period; however, production recommenced in early December 2012. December 2012 production averaged 1,975 bopd gross (198 bopd net) from 10 of the 31 wells development wells drilled into the field to date.

During calendar 2012, the Corporation, through a consortium, entered into an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation receives a tariff price of $39.53 per barrel of incremental oil produced over a pre-determined production base curve under the incremental production contract. Such incremental production volumes are reported as production in this MD&A. Ecuador tariff production has steadily increased in calendar 2012 and is expected to continue to increase into calendar 2013, contributing a significant portion to the Corporation's total production in the future. The operator, PetroEcuador, is responsible for all production expenses related to the incremental production and, consequently, operating netbacks are unaffected by changes in production costs.

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

Average Daily Petroleum and Natural Gas Production and Sales Volumes

Production and sales volumes in this MD&A are reported before royalties and volumes for previous periods have been restated accordingly. The Corporation previously reported such volumes after royalties; however, Shona previously reported its volumes before royalties and the Corporation took a decision to report before royalties for all its assets going forward. The Esperanza field acquired with Shona is expected to be a significant contributor to the Corporation's total production in future periods.

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Production (boepd)						
Rancho Hermoso – non-tariff	**2,679**	4,677	(43%)	**3,084**	4,007	(23%)
Rancho Hermoso – tariff	**1,414**	8,971	(84%)	**1,884**	7,724	(76%)
LLA 23	**433**	-	n/a	**216**	-	n/a
Esperanza	**319**	-	n/a	**160**	-	n/a
Other Colombia	**193**	189	2%	**157**	204	(23%)
Total Colombia	**5,038**	13,837	(64%)	**5,501**	11,935	(54%)
Ecuador – tariff	**316**	-	n/a	**186**	-	n/a
Total production	**5,354**	13,837	(61%)	**5,687**	11,935	(52%)
Inventory movements and adjustments	**(220)**	318	n/a	**541**	247	119%
Total sales	**5,134**	14,155	(64%)	**6,228**	12,182	(49%)
Sales (boepd)						
Rancho Hermoso – non-tariff	**2,714**	5,012	(46%)	**3,735**	4,275	(13%)
Rancho Hermoso – tariff	**1,412**	8,954	(84%)	**1,886**	7,706	(76%)
LLA 23	**199**	-	n/a	**100**	-	n/a
Esperanza	**319**	-	n/a	**160**	-	n/a
Other Colombia	**174**	189	(8%)	**161**	201	(20%)
Total Colombia	**4,818**	14,155	(66%)	**6,042**	12,182	(50%)
Ecuador – tariff	**316**	-	n/a	**186**	-	n/a
Total sales	**5,134**	14,155	(64%)	**6,228**	12,182	(49%)

The overall decrease in production volumes in the three and six months ended December 31, 2012 compared to the same periods in 2011 is primarily due to higher than anticipated natural production declines and increased water cuts in the Mirador formation at Rancho Hermoso, which represents low netback tariff oil production. This was offset by production in Ecuador (316 bopd and 186 bopd, respectively), LLA 23 (433 bopd and 216 bopd, respectively) and the recently acquired Esperanza field (319 boepd and 160 boepd, respectively).

The Rancho Hermoso field is limited in its water handling capacity and, as a result, current and future production from the field is being managed within those capacity constraints. With this in mind, the Corporation continued to focus on optimizing cash flows from its Rancho Hermoso field with the result that the overall production mix further shifted from tariff production towards non-tariff production in the second quarter of fiscal 2013. Since the Corporation reports 100% of tariff production volumes and only its proportionate working interest share of non-tariff production volumes, the shift from tariff to non-tariff production had a pronounced effect on the reported consolidated production volumes; however, operating netbacks for non-tariff production are significantly higher than for tariff production and therefore have an offset effect on operating cash flows. As described above, as of the date hereof all Rancho Hermoso tariff production has been converted to non-tariff formations and the overall production for the field has stabilized.

The successful Labrador discovery well in the LLA 23 field was completed and put on production at the beginning of December 2012 and produced at an average rate of 1,286 bopd for the month of December 2012. Since production was limited to only one month, the overall production volumes for the three and six months ended December 31, 2012 were only minimally impacted by this recent successful well.

With the completion of the Shona acquisition described above, the Corporation added a significant natural gas production asset to its portfolio. However, since the acquisition of Shona was completed on December 21, 2012, the Esperanza field accounted for only a minor amount of the Corporation's total production for the three and six months ended December 31, 2012. Actual average daily production of the Esperanza field for the three and six months ended December 31, 2012 was 2,744 boepd and 2,757 boepd, respectively.

The Corporation continued to realize incremental production from its participation in the incremental production contract in Ecuador, which is expected to increase in future periods as the work program is executed.

The Corporation recently announced production guidance for calendar 2013 of 7,500 to 8,500 boepd, before royalties. As of the date hereof, the Corporation is producing approximately 8,000 boepd, before royalties, and no low netback tariff oil from the Rancho Hermoso field.

Petroleum and Natural Gas Revenues

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Rancho Hermoso – non-tariff	**$ 22,383**	$ 45,805	(51%)	**$ 62,701**	$ 74,271	(16%)
Rancho Hermoso – tariff	**2,255**	14,300	(84%)	**6,025**	23,177	(74%)
LLA 23	**1,624**	-	n/a	**1,624**	-	n/a
Esperanza	**994**	-	n/a	**994**	-	n/a
Other Colombia	**1,084**	1,228	(12%)	**2,096**	2,492	(16%)
Total Colombia	**28,340**	61,333	(54%)	**73,440**	99,940	(27%)
Ecuador – tariff	**1,150**	-	n/a	**1,353**	-	n/a
Petroleum and natural gas revenues, before royalties	**29,490**	61,333	(52%)	**74,793**	99,940	(25%)
Royalties	**(2,140)**	(6,092)	(65%)	**(5,648)**	(9,369)	(40%)
Petroleum and natural gas revenues, after royalties	**$ 27,350**	$ 55,241	(50%)	**$ 69,145**	$ 90,571	(24%)

The decrease in crude oil sales in the three and six months ended December 31, 2012 compared to the same periods in 2011 is primarily the result of the decreased overall sales of 64% and 49%, respectively. The decrease is partially offset by an increase in overall realized prices of 33% and 46%, respectively, resulting from the continued shift from tariff to non-tariff production at the Rancho Hermoso field.

Average Benchmark and Realized Sales Prices

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Brent ($/bbl)	**$ 110.15**	$ 94.02	17%	**$ 109.89**	$ 94.89	16%
West Texas Intermediate ($/bbl)	**$ 88.01**	$ 108.92	(19%)	**$ 90.07**	$ 112.10	(20%)
Rancho Hermoso – non-tariff	**$ 89.64**	$ 99.34	(10%)	**$ 91.23**	$ 94.42	(3%)
Rancho Hermoso – tariff	**17.36**	17.36	-	**17.36**	16.35	6%
LLA 23	**88.54**	-	n/a	**88.54**	-	n/a
Esperanza ($/boe)	**33.87**	-	n/a	**33.87**	-	n/a
Other Colombia ($/bbl)	**67.72**	70.62	(4%)	**70.55**	67.37	5%
Total Colombia ($/boe)	**63.94**	47.10	36%	**66.06**	44.59	48%
Ecuador – tariff ($/bbl)	**39.53**	-	n/a	**39.53**	-	n/a
Average realized sales price ($/boe)	**$ 62.44**	$ 47.10	33%	**$ 65.27**	$ 44.59	46%

The Corporation's overall average realized sales prices increased 33% and 46% in the three and six months ended December 31, 2012, respectively, compared to the same periods in 2011. The increase in overall realized prices is primarily attributable to Rancho Hermoso tariff production contributing a smaller portion to the production/sales mix. In the three and six months ended December 31, 2012, Rancho Hermoso tariff sales represented 27% and 30% of total sales by volume, respectively, compared to 63% and 63% in the same periods in 2011, respectively.

Royalties

	Three months ended December 31, 2012	2011	Six months ended December 31, 2012	2011
Rancho Hermoso – non-tariff	**$ 1,815**	$ 6,000	**$ 5,242**	$ 9,182
LLA 23	**$ 167**	-	**$ 167**	$ -
Esperanza	**$ 77**	$ -	**$ 77**	$ -
Other Colombia	**$ 81**	$ 92	**$ 162**	$ 187

In Colombia, crude oil royalties are taken in kind generally at a rate of 8% until net field production reaches 5,000 boepd, then increase on a sliding scale to 20% up to field production of 125,000 boepd. In addition, the Corporation's LLA 23 block is subject to an additional x-factor royalty of 3% (effectively 2.76%). The Corporation's Capella heavy oil field is subject to a 6% royalty. There are no royalties on tariff production either in Colombia or Ecuador. Natural gas royalties are also taken in kind, generally at a rate of 6.4%.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended December 31, 2012	2011	Change	Six months ended December 31, 2012	2011	Change
Production expenses	**$ 15,549**	$ 15,689	(1%)	**$ 37,281**	$ 24,151	54%
Transportation expenses	**2,820**	7,884	(64%)	**6,815**	12,691	(46%)
Total production and transportation expenses	**$ 18,369**	$ 23,573	(22%)	**$ 44,096**	$ 36,842	20%
$/boe	**$ 38.89**	$ 18.10	115%	**$ 38.48**	$ 16.44	134%

An analysis of production expenses is provided below:

	Three months ended December 31, 2012	2011	Change	Six months ended December 31, 2012	2011	Change
Rancho Hermoso – non-tariff	**$ 12,675**	$ 9,363	35%	**$ 31,024**	$ 14,566	113%
Rancho Hermoso – tariff	**1,500**	4,767	(69%)	**3,545**	7,289	(51%)
LLA 23	**144**	-	n/a	**144**	-	n/a
Esperanza	**85**	-	n/a	**85**	-	n/a
Other Colombia	**1,145**	1,559	(27%)	**2,483**	2,296	8%
Total production expenses	**$ 15,549**	$ 15,689	(1%)	**$ 37,281**	$ 24,151	54%
$/boe						
Rancho Hermoso – non-tariff	**$ 50.76**	$ 20.31	150%	**$ 45.14**	$ 18.52	144%
Rancho Hermoso – tariff	**$ 11.55**	$ 5.79	100%	**$ 10.21**	$ 5.14	99%
LLA 23	**$ 7.88**	$ -	n/a	**$ 7.88**	$ -	n/a
Esperanza	**$ 2.90**	$ -	n/a	**$ 2.90**	$ -	n/a
Total production expenses	**$ 32.92**	$ 12.05	173%	**$ 32.53**	$ 10.77	202%

Production expenses decreased 1% in total and increased 173% per boe in the second quarter of 2013 compared to 2012 primarily related to increased diesel prices and consumption, increased repair and maintenance costs due to operational changes and issues arising at the Rancho Hermoso field, operations in LLA 23, as well as increased water handling costs, offset by lower production volumes and a recovery of the input gas purchases accrual from the previous quarter.

Production expenses increased 54% in total and increased 202% per boe in the first half of 2013 compared to 2012 primarily related to increased diesel prices and consumption, gas plant operations and input gas purchases, operations in LLA 23, increased repair and maintenance costs due to operational changes and issues arising at the Rancho Hermoso field, as well as increased water handling costs, offset by lower production volumes.

Under its contract with Ecopetrol, the Corporation pays 100% of the production costs on its Rancho Hermoso field. As a result, production expenses per boe for Rancho Hermoso non-tariff oil are higher as a result of the Corporation only recognizing non-tariff production before royalties of approximately 24-25% of gross non-tariff production.

Gas purchases and production costs with respect to the gas plant accounted for $3.5 million of total production expenses in the first half of fiscal 2013, with the resulting naphtha and LPG production recognized in Rancho Hermoso petroleum sales. Gas plant operations commenced in June 2012 and, consequently, the first half of fiscal 2013 included start-up costs related to such. In addition, crude oil inventory was significantly lower as at December 31, 2012 compared to 2011, resulting in higher production expenses being recognized during the first half of fiscal 2013 compared to the amount being capitalized in inventory at December 31, 2012. Further, LLA 23 operations commenced in December 2012 and, consequently, resulted in increased production expenses in the first half of fiscal 2013 as compared to 2012.

The operational issues at the Rancho Hermoso field continue to be rectified by: 1) the replacement of faulty injector pumps in order to optimize production; 2) conversion of tariff production into NRI production to reduce water handling costs; and 3) completion of the power generation project at the gas plant, which is expected to significantly reduce diesel consumption at the field going forward. All such initiatives are expected to be completed by the end of the first quarter of calendar 2013.

As a new discovery, LLA 23 was operated during the reporting period using high cost temporary production facilities that are expected to be replaced shortly with permanent facilities, including a generator that uses low cost LPGs from the Rancho Hermoso field.

As described above, the Corporation expects Ecuador to increasingly contribute to its production mix in future periods. The Corporation does not pay production costs in Ecuador.

An analysis of transportation expenses is provided below:

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Rancho Hermoso – non-tariff	**$ 2,101**	$ 5,974	(65%)	**$ 5,404**	$ 9,508	(43%)
Rancho Hermoso – tariff	**271**	1,242	(78%)	**707**	2,427	(71%)
LLA 23	**219**	-	n/a	**219**	-	n/a
Other Colombia	**229**	668	(66%)	**485**	756	(36%)
Total transportation expenses	**$ 2,820**	$ 7,884	(64%)	**$ 6,815**	$ 12,691	(46%)
$/boe						
Rancho Hermoso – non-tariff	**$ 8.41**	$ 12.96	(35%)	**$ 7.86**	$ 12.09	(35%)
Rancho Hermoso – tariff	**$ 2.09**	$ 1.51	38%	**$ 2.04**	$ 1.71	19%
LLA 23	**$ 11.91**	$ -	n/a	**$ 11.91**	$ -	n/a
Total transportation expenses	**$ 5.97**	$ 6.05	(1%)	**$ 5.95**	$ 5.66	5%

Total transportation expenses have decreased in the three and six months ended December 31, 2012 compared to the same periods in 2011 mainly due to decreased sales volumes.

As described above, the Corporation expects Ecuador to increasingly contribute to its production mix in future periods. The Corporation does not pay transportation costs in Ecuador.

Operating Netback

	Three months ended December 31,			Six months ended December 31,		
$/boe	**2012**	2011	Change	**2012**	2011	Change
Petroleum and natural gas revenues, before royalties	**$ 62.44**	$ 47.10	33%	**$ 65.27**	$ 44.59	46%
Royalties	**(4.54)**	(4.68)	(3%)	**(4.93)**	(4.18)	18%
Production and transportation expenses	**(38.89)**	(18.10)	115%	**(38.48)**	(16.44)	134%
Operating netback	**$ 19.01**	$ 24.32	(22%)	**$ 21.86**	$ 23.97	(9%)

Operating netbacks by major production categories were as follows:

	Three months ended December 31,			Six months ended December 31,		
$/boe	2012	2011	Change	2012	2011	Change
Rancho Hermoso – non-tariff						
Crude oil and natural gas liquids revenues	$ 89.64	$ 99.34	(10%)	$ 91.23	$ 94.42	(3%)
Royalties	(7.27)	(13.02)	(44%)	(7.63)	(11.67)	(35%)
Production and transportation expenses	(59.17)	(33.26)	78%	(53.00)	(30.61)	73%
Operating netback	$ 23.20	$ 53.06	(56%)	$ 30.60	$ 52.14	(41%)
Rancho Hermoso – tariff						
Crude oil tariff revenues	$ 17.36	$ 17.36	-	$ 17.36	$ 16.35	6%
Production and transportation expenses	(13.63)	(7.30)	87%	(12.25)	(6.86)	79%
Operating netback	$ 3.73	$ 10.06	(63%)	$ 5.11	$ 9.49	(46%)
LLA 23						
Crude oil and natural gas liquids revenues	$ 88.54	$ -	n/a	$ 88.54	$ -	n/a
Royalties	(9.12)	-	n/a	(9.12)	-	n/a
Production and transportation expenses	(19.79)	-	n/a	(19.79)	-	n/a
Operating netback	$ 59.63	$ -	n/a	$ 59.63	$ -	n/a
Esperanza						
Natural gas revenues	$ 33.87	$ -	n/a	$ 33.87	$ -	n/a
Royalties	(2.62)	-	n/a	(2.62)	-	n/a
Production expenses	(2.90)	-	n/a	(2.90)	-	n/a
Operating netback	$ 28.35	$ -	n/a	$ 28.35	$ -	n/a
Total Colombia						
Petroleum and natural gas revenues	$ 63.94	$ 47.10	36%	$ 66.06	$ 44.59	48%
Royalties	(4.83)	(4.68)	3%	(5.09)	(4.18)	22%
Production and transportation expenses	(41.44)	(18.10)	129%	(39.66)	(16.44)	141%
Operating netback	$ 17.67	$ 24.32	(27%)	$ 21.31	$ 23.97	(11%)
Ecuador – tariff						
Crude oil tariff revenues	$ 39.53	$ -	n/a	$ 39.53	$ -	n/a
Operating netback	$ 39.53	$ -	n/a	$ 39.53	$ -	n/a

Other fields in Colombia contributed only a minor amount to total revenue (<5%) in the three and six months ended December 31, 2012 and 2011 and, therefore, a separate operating netback analysis was not provided in the table above.

General and Administrative Expenses

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	2012	2011	Change
Gross costs	$ 6,406	$ 6,466	(1%)	$ 11,612	$ 10,441	11%
Less: capitalized amounts / reversal	(496)	(1,777)	(72%)	(979)	(3,211)	(70%)
General and administrative expenses	$ 5,910	$ 4,689	26%	$ 10,633	$ 7,230	47%
$/boe	$ 12.51	$ 3.60	248%	$ 9.28	$ 3.23	188%

Gross general and administrative expenses decreased 1% and increased 11% in the three and six months ended December 31, 2012, respectively, compared to the same period in 2011. During 2011, the Corporation grew significantly, resulting in increased staff to support operations in Colombia. During 2012, the Corporation made efforts to manage its general and administrative expenses despite an increase in the number of staff. Included in the gross costs for the three months ended December 31, 2012 were accrued bonuses of $1.1 million (2011 - $2.3 million).

The Corporation expects to realize significant synergies on general and administrative expenses in calendar 2013 with the integration of Shona.

Net Finance Income and Expense

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Net interest expenses	**$ 231**	$ 468	(51%)	**$ 178**	$ 195	(9%)
Non-cash financing costs	**2,178**	279	681%	**2,442**	449	444%
Net finance expense	**$ 2,409**	$ 747	222%	**$ 2,620**	$ 644	307%

Interest – Interest expense increased in the three and six months ended December 31, 2012 compared the same periods in 2011 due to interest incurred on bank debt and the recording of a non-cash financing cost related to the phantom warrants issued on closing of the Shona term loan, offset by a combination of lower convertible debenture debt levels and higher capitalization of borrowing costs.

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 December 31, 2012, the Corporation had four financial oil collars outstanding under the following terms:

Period	**Volume**	**Type**	**Price Range**
Jul 2012 – Jun 2013	750 bbls/day	Financial Brent Oil Collar	$85.00 – $107.50
Jul 2012 – Jun 2013	750 bbls/day	Financial Brent Oil Collar	$85.00 – $106.80
Jul 2013 – Dec 2013	500 bbls/day	Financial Brent Oil Collar	$85.00 – $107.50
Jul 2013 – Dec 2013	500 bbls/day	Financial Brent Oil Collar	$85.00 – $106.80

Gains and losses on commodity contracts recognized in net income/loss are summarized below:

	Three months ended December 31,		Six months ended December 31,	
	2012	2011	**2012**	2011
Unrealized change in fair value	**$ (1,584)**	$ 162	**$ 2,148**	$ (454)
Realized cash settlement	**394**	-	**911**	78
Total gain (loss)	**$ (1,190)**	$ 162	**$ 3,059**	$ (376)

Stock-Based Compensation Expense

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Gross costs	**$ 1,517**	$ 2,696	(44%)	**$ 3,591**	$ 6,266	(43%)
Less: capitalized amounts	**(658)**	(1,106)	(41%)	**(1,551)**	(2,198)	(29%)
Stock-based compensation expense	**$ 859**	$ 1,590	(46%)	**$ 2,040**	$ 4,068	(50%)

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 and Depreciation Expense

	Three months ended December 31,			Six months ended December 31,		
	2012	2011	Change	**2012**	2011	Change
Depletion and depreciation expense	**$ 10,195**	$ 14,516	(30%)	**$ 23,494**	$ 23,039	2%
$/boe	**$ 21.58**	$ 11.15	94%	**$ 20.50**	$ 10.28	99%

Income Tax Expense

	Three months ended December 31, 2012	2011	Six months ended December 31, 2012	2011
Current income tax expense (recovery)	$ (758)	$ 435	$ (1,643)	$ 4,350
Deferred income tax expense	2,589	9,272	1,018	12,032
Income taxes	**$ 1,831**	$ 9,707	**$ (625)**	$ 16,382

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 33%.

Cash and Funds from Operations and Net Income (Loss)

	Three months ended December 31, 2012	2011	Change	Six months ended December 31, 2012	2011	Change
Cash provided by operating activities	**$ 4,617**	$ 35,758	(87%)	**$ 15,021**	$ 65,894	(77%)
Funds from operations (1)	**$ 2,943**	$ 24,480	(88%)	**$ 17,034**	$ 42,241	(60%)
Per share – basic	**$ 0.05**	$ 0.45	(90%)	**$ 0.27**	$ 0.80	(66%)
Per share – diluted	**$ 0.05**	$ 0.45	(90%)	**$ 0.27**	$ 0.78	(65%)
Net income (loss) (1)	**$ 3,131**	$ (2,423)	n/a	**$ (3,083)**	$ 11,063	n/a
Per share – basic	**$ 0.05**	$ (0.04)	n/a	**$ (0.05)**	$ 0.21	n/a
Per share – diluted	**$ 0.05**	$ (0.04)	n/a	**$ (0.05)**	$ 0.20	n/a

(1) Effective December 20, 2012, the Corporation completed a 10:1 consolidation of its common shares. Consequently, per share information presented above was restated to a post-consolidation basis for comparability.

Capital Expenditures

	Three months ended December 31, 2012	2011	Six months ended December 31, 2012	2011
Drilling and completions	**$ 13,566**	$ 25,068	**$ 19,120**	$ 40,263
Facilities and infrastructure	**4,238**	21,729	**7,100**	30,833
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other	**4,863**	15,628	**15,378**	22,685
Total capital expenditures, excluding business acquisition	**$ 22,667**	$ 62,425	**$ 41,598**	$ 93,781
Recorded as:				
Expenditures on exploration and evaluation assets	**$ 12,854**	$ 10,941	**$ 17,635**	$ 17,664
Expenditures on property, plant and equipment	**$ 9,813**	$ 51,484	**$ 23,963**	$ 76,117

Capital expenditures in the second quarter of 2013 primarily relate to:

- Drilling, completion and facility costs at LLA 23 related to the Labrador discovery;
- Recompletion and facility costs at Rancho Hermoso;
- Drilling costs for stratigraphic wells at Cedrela and Portofino;
- Drilling, completion and facility costs at the Capella field (non-operated);
- Drilling, completion and recompletion costs at the Ecuador fields (non-operated).

LIQUIDITY AND CAPITAL RESOURCES

Capital Management

The Corporation's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain investor, creditor and market confidence. The Corporation manages its capital structure and makes adjustments in response to changes in economic conditions and the risk characteristics of the underlying assets. The Corporation considers its capital structure to include common share capital, convertible debentures, bank debt and working capital, defined as current assets less current liabilities, excluding the current portion of commodity contracts and the current portion of any embedded derivatives asset/liability. In order to maintain or adjust the capital structure, from time to time the Corporation may issue common shares or other securities, sell assets or adjust its capital spending to manage current and projected debt levels.

The Corporation monitors leverage and adjusts its capital structure based on the ratio of net debt to funds from operations. This ratio is calculated as net debt, defined as the principal amount of its outstanding bank debt plus the principal amount of its convertible debentures, unless the debentures are in-the-money or may otherwise be settled in common shares at the option of the Corporation, less working capital, adjusted for the current portion of bank debt and convertible debentures included above, divided by funds from operations. The Corporation uses the ratio of net debt to funds from operations as a key indicator of the Corporation's leverage and to monitor the strength of its financial position. The calculation has been adjusted in the current quarter to include the results of Shona for the full period on a pro forma basis, thereby appropriately matching funds from operations against related debt and providing a more meaningful ratio. Further, adjustments have been made to Shona's funds from operations to remove all transaction costs associated with the acquisition by Canacol ($4.9 million) and to reflect savings to general and administrative expenses that were effective on completion of the acquisition. Shona's adjusted funds from operations for the three months ended December 31, 2012 were $5.6 million, with $0.6 million included in the reported consolidated results of the Corporation.

In order to facilitate the management of this ratio, the Corporation prepares annual budgets, which are updated as necessary depending on varying factors including current and forecast crude oil prices, changes in capital structure, execution of the Corporation's business plan and general industry conditions. The annual budget is approved by the Board of Directors and updates are prepared and reviewed as required.

		December 31, 2012
Bank debt (current and long-term) – principal	$	103,615
Working capital surplus, excluding the current portion of bank debt and derivatives		(52,042)
Net debt	$	51,573
Pro forma annualized funds from operations (see note above)	$	30,900
Net debt to funds from operations		1.7

The Corporation recently experienced a decline in its crude oil production at the Rancho Hermoso field, which impacted overall corporate profitability both through reduced revenues and higher per unit production costs, and also had the effect of reducing the borrowing capacity of the Corporation through its syndicated credit facility, thereby requiring the repayment of the deficiency over a six month period as further described below. As a result, the Corporation undertook initiatives to reverse the impact through reduced and deferred spending, diversification and increases to its production base, and arranging access to additional sources of capital to ensure liquidity. Significantly, the Corporation completed the Shona acquisition on December 21, 2012, which added significant production and operating cash flows, and also drilled a successful light oil well at LLA 23, which commenced production in early December 2012. The Corporation is also expecting increased production from its Ecuador incremental oil project in 2013, which has performed up to expectations. As a result, the Corporation has a significantly more diversified production base, which is expected to provide more stable operating cash flows in calendar 2013 and reduce the trailing leverage ratio as calculated above. The Corporation will continue with initiatives into calendar 2013 to increase production and cash flows, to reduce its cost structure and extract cost synergies from the Shona acquisition, and to manage its overall credit facilities to ensure sufficient capital availability, while maintaining a high-impact capital program.

Credit Facilities and Debt

Syndicated Credit Facility

The Corporation, through its wholly-owned subsidiary Canacol Energy Colombia S.A., has in place a $200 million syndicated credit facility with an approved borrowing base of $33.0 million. The credit facility consists of a reserve-based revolving facility and an amortized term facility.

The revolving facility has a three-year term maturing on June 29, 2015 and is subject to re-determination of the borrowing base semi-annually on April 1 and October 1 each year. The borrowing base is determined based on, among other things, the Corporation's current reserve report, results of operations, the lender's view of the current and forecasted commodity prices and the current economic environment. Advances under the revolving facility bear interest at rates ranging from LIBOR plus 2.50% to 3.25% per annum, depending on utilization. Undrawn amounts under the revolving facility bear a commitment fee of 0.50% per annum.

The term facility bears interest at LIBOR plus 2.50% and is repayable in ten equal principal instalments of $3.0 million plus accrued interest due at the end of each three month period starting on September 1, 2012. Repayments under the term facility result in a corresponding increase in the amounts that are available under the revolving facility such that the total amount available always equals the approved borrowing base.

The combined credit facility is secured by certain of the Corporation's oil and gas assets and reserves. At December 31, 2012, $41.0 million was drawn under the combined credit facility and an additional amount of $5.8 million was guaranteed under a letter of credit. The $5.8 million letter of credit is expected to be cancelled and replaced for a significantly lower amount during calendar Q1 2013.

The borrowing base was re-determined in late December 2012 to $33.0 million, compared to the total amount drawn or guaranteed under the facility at the time of $46.8 million. Consequently, under the credit agreement, the Corporation must cure the deficiency of $13.8 million through equal instalments of $2.3 million per month over the next six months. The repayments have been reclassified to current liabilities on the interim condensed consolidated statement of financial position. The results of the Corporation's recent successful light oil well on the LLA 23 block were not considered in the borrowing base re-determination as sufficient information was not available at the time.

Shona Term Loan

In connection with the closing of the Shona business acquisition on December 21, 2012, the Corporation entered into a senior secured credit agreement for $45.0 million. This credit facility carries a term of one year, is repayable in full upon maturity, bears interest at 15% per annum, payable quarterly, and is secured by the assets of Shona. In consideration for entering into the credit agreement, the Corporation agreed to a "phantom warrant payment" arrangement such that the Corporation will pay an amount (in cash or Canacol Shares, at the election of the Corporation) equal to the in-the-money amount of 2,697,292 common share purchase warrants of the Corporation at an exercise price of C$4.50 per Canacol Share. The phantom warrant payment may be demanded partially or in full at any time for a period of three years.

The Corporation expects to refinance this term loan with the existing lender during calendar 2013 into an amortized term facility.

Other Colombian Credit Facilities

The Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $21.6 million (COP$ 38.1 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. At December 31, 2012, $17.5 million was drawn under the facilities, a decision taken in December 2012 to ensure adequate short-term liquidity while the syndicated credit facility was under redetermination.

Letters of Credit

At December 31, 2012, the Corporation had letters of credit outstanding totalling $23.8 million to guarantee work commitments on exploration blocks and to guarantee other contractual commitments. The total of these letters of credit reduce the amounts available under the syndicated credit facility ($5.8 million) and the Colombian revolving lines of credit ($4.1 million, net of amounts counter-guaranteed by other financial institutions), each described above.

Convertible Debentures

The Corporation has convertible debentures outstanding with a face value of $25.7 million (fair value – $24.4million) that mature on July 15, 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$10.526 per share, being the ratio of 95 common shares per C$1,000 principal amount of the debentures. On the maturity date, the Corporation has a right to repay the outstanding principal amount and any accrued interest in common shares of the Corporation, subject to certain conditions including customary regulatory approvals.

Share Capital

At February 11, 2013, the Corporation had 86.5 million common shares, 5.4 million warrants and 5.8 million stock options outstanding.

Contractual Obligations

The following table provides a summary of the Corporation's cash requirements to meet its financial liabilities and contractual obligations existing at December 31, 2012:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	88,373	42	15,200	103,615
Trade and other payables	23,783	-	-	23,783
Deferred income	2,500	-	-	2,500
Commodity contracts	2,575	-	-	2,575
Equity tax payable – undiscounted	1,888	1,248	-	3,136
Convertible debentures – principal	-	25,650	-	25,650
Convertible debentures – interest	2,020	3,030	-	5,050
Phantom warrants	-	-	2,526	2,526
Warrants	495	2,889	-	3,384
Exploration contracts (see below)	12,317	35,297	-	47,614
Incremental production contract (Ecuador)	18,511	61,793	-	80,304
Office leases	1,703	1,813	5,548	9,064
	154,165	131,762	23,274	309,201

Exploration Contracts

The Corporation has entered into a number of exploration contracts in Colombia, Brazil and Guyana and Peru which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at December 31, 2012 of $47.6 million and has issued $23.8 million in financial guarantees related thereto. These commitments are planned to be satisfied by means of seismic work, exploration drilling and farm-outs.

Incremental Production Contract

In February 2012, a company in which the Corporation has a non-operated 25.0% equity participation interest (27.9% capital participation interest) was awarded a 15 year incremental production contract by the national oil company of Ecuador ("Petroecuador" or "EPPE") for the Libertador and Atacapi mature fields in Northern Ecuador. The operator is required to spend a total of $334.0 million ($93.3 million, net to the Corporation) over the 15 year period of the contract. As described in the "Outlook" section below, Ecuador is expected to become increasingly significant to the overall operations of the Corporation.

SUBSEQUENT EVENT

On January 30, 2013, the Corporation granted 1,863,000 stock options to its directors, officers and employees. The options have an exercise price of C$3.38, which was the market price of the shares at the close of trading on January 30, 2013.

OUTLOOK

The Corporation plans to spend capital expenditures of $67 million in calendar 2013 on drilling, workovers, seismic, production facilities, and pipelines in Colombia and Ecuador, and anticipates net average production before royalties of between 7,500 and 8,500 boepd over the period.

In calendar 2013, the Corporation will focus on: 1) building out production and reserves from recent oil discoveries on LLA 23 and VMM2 and increasing production levels from the newly acquired Esperanza gas field in Colombia via new sales contracts; 2) continuing to increase production and reserves from the Libertador-Atacapi oil fields in Ecuador; and 3) execute a significant oil-focused exploration program in Colombia targeting 44 million barrels of net risked prospective conventional light and heavy oil, and unconventional light oil resources. Exploration projects of significance for calendar 2013 include exploration wells on LLA 23 targeting light oil, exploration wells on each of the Corporation's three Middle Magdalena blocks (Santa Isabel, VMM2 and VMM3) targeting both shallow conventional light oil and deeper unconventional shale oil, and the continuation of the heavy oil exploration program on assets in the Putumayo-Caguan Basin. Funding for the calendar 2013 capital program is expected to come from working capital, operating cash flows and debt facilities.

SUMMARY OF QUARTERLY RESULTS

	2013		2012				2011	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial								
Petroleum and natural gas revenues, net of royalties	**27,350**	41,795	45,702	48,632	55,241	35,330	47,015	32,129
Funds from operations (1)	**2,943**	14,091	9,645	20,042	24,480	17,761	17,515	18,024
Per share – basic (2)	**0.05**	0.22	0.15	0.32	0.45	0.35	0.30	0.38
Per share – diluted (2)	**0.05**	0.22	0.15	0.32	0.45	0.33	0.30	0.38
Net income (loss)	**3,777**	(6,214)	3,830	3,663	(2,423)	13,486	18,407	(852)
Per share – basic (2)	**0.05**	(0.10)	0.06	0.06	(0.04)	0.25	0.32	(0.02)
Per share – diluted (2)	**0.05**	(0.10)	0.06	0.06	(0.04)	0.24	0.32	(0.02)
Capital expenditures	**22,667**	18,931	39,927	52,424	62,425	31,356	24,661	20,665
Operations								
Petroleum and natural gas production, before royalties (boepd)								
Petroleum	**5,035**	6,020	10,670	13,598	13,837	10,033	11,777	10,212
Natural gas	**319**	-	-	-	-	-	-	-
Total	**5,354**	6,020	10,670	13,598	13,837	10,033	11,777	10,212

(1) Non-IFRS measure – see "Non-IFRS Measures" section.
(2) Effective December 20, 2012, the Corporation completed a 10:1 consolidation of its common shares. Consequently, per share information presented above was restated to a post-consolidation basis for comparability.

RISKS AND UNCERTAINTIES

There have been no significant changes in the three months ended December 31, 2012 to the risks and uncertainties as identified in the MD&A for the year ended June 30, 2012.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgements, assumptions and estimates in the preparation of the 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 financial statements.

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 audited consolidated financial statements as at and for the year ended June 30, 2012.

REGULATORY POLICIES

Disclosure Controls and Procedures

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. Subject to scope limitation described below, 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. With the assistance of expert advisors and other members of management, the Corporation's CEO and CFO have assessed (subject to the scope limitation described below) the design of the Corporation's DC&P as at December 31, 2012 and have not identified any material weaknesses relating to the design of the Corporation's DC&P framework.

Internal Control 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 ("ICFR") to provide reasonable assurance regarding the reliability of financial statements prepared in accordance with IFRS. With the assistance of expert advisors and other members of management, the Corporation's CEO and CFO have assessed (subject to the scope limitation described below) the design effectiveness of the Corporation's ICFR as at December 31, 2012, 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") and have not identified any material weaknesses relating to the design of the Corporation's ICFR framework.

During the quarter ended December 31, 2012, 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.

Limitation on Scope of Design

In accordance with section 3.3 (1)(b) of National Instrument 52-109, which allows an issuer to limit its design of DC&P and ICFR to exclude controls, policies and procedures of a business that the issuer acquired not more than 365 days prior to the end of the fiscal period, the controls, policies and procedures of Shona, which was acquired by the Corporation effective December 21, 2012, have been excluded from the control design assessments discussed above. The scope limitation is based on the time required to document and assess the DC&P and ICFR of Shona in a manner consistent with the Corporation's other operations. The Corporation's management is currently in the process of integrating Shona into the existing internal controls and procedures of Canacol.

Shona constitutes 39% of net assets, 33% of total assets, 1% of net revenues, and 6% of income before income taxes of the consolidated financial statement amounts as at and for the quarter ended December 31, 2012.

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.