CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE MONTHS ENDED SEPTEMBER 30, 2012

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended September 30, 2012	2011	Change
Crude oil sales, net of royalties	**37,822**	26,453	43%
Tariff revenue	**3,973**	8,877	(55%)
Total revenues	**41,795**	35,330	18%
Funds from operations [1]	**14,091**	17,761	(21%)
Per share – basic and diluted ($)	**0.02**	0.03	(30%)
Net income (loss)	**(6,214)**	13,486	n/a
Per share – basic and diluted ($)	**(0.01)**	0.03	n/a
Capital expenditures	**18,931**	31,356	(40%)
	September 30,2012	June 30, 2012	Change
Cash and cash equivalents	**31,088**	30,789	1%
Restricted cash	**10,378**	6,555	58%
Working capital surplus [1]	**21,742**	17,697	23%
Long-term bank debt	**30,153**	15,986	89%
Total assets	**412,266**	406,828	1%
Common shares, end of period (000s)	**618,982**	618,982	-

Operating	Three months ended September 30, 2012	2011	Change
Crude oil production (bopd)			
Tariff	**2,410**	6,476	(63%)
NRI	**3,332**	3,274	2%
Total	**5,742**	9,750	(41%)
Crude oil sales (bopd)			
Tariff	**2,417**	6,458	(63%)
NRI	**4,505**	3,452	31%
Total	**6,922**	9,910	(30%)
Rancho Hermoso – tariff oil operating netback ($/bbl) [1]			
Realized tariff oil price	**17.36**	14.94	16%
Operating and transportation costs	**(11.43)**	(6.23)	83%
RH tariff oil operating netback	**5.93**	8.71	(32%)
Rancho Hermoso – non-tariff (NRI) oil operating netback ($/bbl) [1]			
Realized crude oil price, net of royalties	**95.88**	84.43	14%
Operating and transportation costs	**(50.60)**	(29.26)	73%
RH NRI oil operating netback	**45.28**	55.17	(18%)

(1) Non-IFRS measure. See "Non-IFRS Measures" section within MD&A.

Financial Highlights for the Three Months Ended September 30, 2012

Financial highlights of Canacol Energy Ltd. ("Canacol" or the "Corporation") include:

- Total revenues for the three months ended September 30, 2012 increased 18% to $41.8 million from $35.3 million for the comparable period.
- Funds from operations for the three months ended September 30, 2012 decreased 21% to $14.1 million from $17.8 million for the comparable period.
- Net loss for the three months ended September 30, 2012 was $6.2 million compared to net income of $13.5 million for the comparable period.
- Capital expenditures for the three months ended September 30, 2012 were $18.9 million.
- Average daily sales volumes decreased 30% to 6,922 barrels of oil per day ("bopd") for the three months ended September 30, 2012 compared to 9,910 bopd for the comparable period. This compares to 10,814 bopd for the three months ended June 30, 2012. As described below, the decrease from the fourth quarter of 2012 was due to a combination of well shut-ins, a civil road blockage, water handling constraints, and natural production declines, and was offset by a change in crude oil inventory. Downtime during the first quarter of fiscal 2013 was 5% in July, 3% in August, and 37% in September, resulting in an overall average downtime of 15% for the quarter. Further, the decrease in sales volumes is also significantly impacted by the continuing shift of tariff production to NRI production to optimize cash flows in the Rancho Hermoso field, which results in lower reported total volumes since tariff production volumes are reported 100% while NRI production volumes are only reported at 22.4% in the first quarter of 2013. However, Rancho Hermoso NRI production receives a significantly higher operating netback compared to tariff production.
- Starting in September 2012, Ecuador fields have begun providing incremental production to the Corporation and are expected to see significant increased production in future periods as the development program is executed. For the three months ended September 30, 2012, average incremental production from the fields was 223 bopd, approximately 56 bopd of which is the Corporation's share. For the months of October and November, average gross incremental production from the fields were 827 bopd and 1,595 bopd, respectively, of which, approximately 207 bopd and 399 bopd are the Corporation's share, respectively.
- For the three months ended September 30, 2012, the Corporation's operating netback for Rancho Hermoso non-tariff (NRI) production decreased 18% to $45.28/bbl from $55.17/bbl for the comparable period. For the three months ended September 30, 2012, the Corporation's operating netback for Rancho Hermoso tariff production decreased 32% to $5.93/bbl from $8.71/bbl for the comparable period. The decrease in operating netbacks was primarily due to an increase in operating expenses. Operating expenses increased 157% in total and 268% per barrel in the first quarter of 2013 compared to 2012 primarily related to gas plant operations and input gas purchases, increased diesel prices and consumption, as well as increased water handling costs. Further, multiple incidents of injection pump failures occurred during the three months ended September 30, 2012, which resulted in increased repair and maintenance costs as well as increased production downtime during the quarter, as further described above. In particular, gas purchases and operating costs with respect to the gas plant accounted for $4.2 million of total operating expenses in the first quarter of fiscal 2013 with the resulting naphtha and LPG production recognized in NRI sales (to the extent it is blended with NRI oil) and liquids sales. Gas plant operations commenced in June 2012 and, consequently, first quarter fiscal 2013 continued to realize start-up costs related to such. The operational issues are currently being rectified by (1) the replacement of faulty injector pumps in order to optimize production and reduce repair and maintenance costs, (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 Rancho Hermoso field going forward. All such initiatives are expected to be completed by the end of the first quarter of calendar 2013.
- At September 30, 2012, the Corporation had $41.5 million in cash, cash equivalents and restricted cash, and $21.7 million of working capital surplus, including the current portion of long-term debt.

OPERATIONAL UPDATE

Llanos Basin, Colombia

Rancho Hermoso Field (operator, 100% working interest)
LLA 23 E&P contract (80% working interest)

The Corporation's Rancho Hermoso production volumes continued to be affected in the first quarter of 2013 by higher than anticipated natural production declines and increased water cuts, thereby limiting production due to water handling capacity. The Corporation also experienced a civil road blockage at the Rancho Hermoso field which caused a temporary shut-in from September 21, 2012 to October 2, 2012.

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 continues to focus on optimizing cash flows from its Rancho Hermoso field with the result that the overall production mix has further shifted from tariff production towards NRI production in the first quarter of 2013. Since the Corporation reports 100% of tariff production volumes and only its proportionate working interest share, after royalties, of NRI production volumes (Q1 2013 – 22.4%), the shift from tariff to NRI production has a pronounced effect on the reported consolidated production volumes; however, operating netbacks for NRI production are significantly higher than for tariff production and therefore have an offset effect on operating cash flows.

In late October 2012, the Corporation spud the exploration well in the Labrador prospect on the LLA 23 E&P contract, which is located approximately five kilometers directly north of the Rancho Hermoso field. The exploration well is planned be drilled to a total depth of approximately 11,200 feet measured depth and is expected to take approximately 20 days to drill. This exploration well is targeting potential light oil resources in the same prolific reservoirs currently producing from the Rancho Hermoso field immediately to the south. The Corporation has also completed the acquisition of an additional 31 square kilometers of 3D seismic on the northern part of the contract where two well-developed leads have been identified on the basis of the existing 2D seismic along the same Rancho Hermoso fault trend. Canacol anticipates drilling a number of these prospects in 2013.

Caguan-Putumayo Basin, Colombia

Ombu E&P Contract – Capella heavy oil discovery (10% working interest)
Cedrela E&P Contract (operator, 100% working interest)
Portofino E&P Contract (40% working interest)
Sangretoro E&P Contract (operator, 100% working interest)
Tamarin E&P Contract (operator, 100% working interest)
Achapo E&P contract (operator, 100% working interest)

In June 2012, the Corporation announced the start of its heavy oil exploration drilling program on its Portofino and Cedrela E&P contracts located in the Caguan-Putumayo Basin in Colombia, which commenced in August 2012 and is expected to end in early 2013.

In July 2012, the Corporation announced that Pacific Rubiales Energy Corp. ("Pacific Rubiales") executed a binding agreement with Petrolera Monterrico Sucursal Colombia, whereby it has agreed to acquire from them a 40% net participating interest in the Portofino E&P contract. Concurrently, Pacific Rubiales also executed an agreement with the Corporation whereby, among other things, the Corporation agreed to transfer operatorship of the contract to Pacific Rubiales following completion of the next four wells to be drilled on the contract. Under the terms of the agreement, Pacific Rubiales will operate any commercial discoveries made on the contract. In consideration for the transfer of operatorship, Pacific Rubiales agreed to pay the Corporation $3.7 million and agreed to provide the Corporation with the option to participate pro-rata in its interest in the Portofino contract, as well as in all pipelines and transportation infrastructure projects in which Pacific Rubiales participates in respect of the evacuation of crude from the area. Canacol maintains a 40% net participating interest and is the designated operator of the Portofino contract.

In September 2012, the Corporation completed the drilling of the first stratigraphic test, Achote 1 on the Portofino E&P contract. The well was drilled to 4,300 feet measured depth and encountered approximately 60 feet of basal sandstone with porosities up to 25% and heavy oil shows while drilling. The sandstones also exhibited heavy oil shows while drilling. The results of the well confirm the presence of an active heavy oil hydrocarbon system in this previously undrilled frontier exploration contract. These results, along with the results of the other three stratigraphic wells planned on the Portofino E&P contract will be used to plan the drilling of a conventional exploration well on the contract in 2013. The Corporation is currently acquiring 45 square kilometers of 3D seismic and 58 kilometers of 2D seismic in the southern part of the contract, and plans to use the data to drill the remaining 3 stratigraphic wells in calendar 2012 and extending into calendar first quarter 2013.

In late August 2012, the Corporation was the successful bidder for the Achapo E&P contract in the Mini-Ronda, and anticipates being formally awarded the contract in late calendar 2012. The Achapo contract is 52,799 acres (21,369 hectares) in area and is situated between the Cedrela and Portofino E&P contracts. The first exploration commitment phase is 18 months, with a commitment to acquire 42 kilometers of 2D seismic for an investment of $0.8 million. The Achapo contract contains the extension of several large prospects and leads identified on 2D seismic data recently acquired on the Cedrela contract in calendar 2011, which are similar in style and size to the nearby Capella heavy oil discovery.

In late October 2012, the Corporation spud the Guarango 1 stratigraphic test on the Cedrela E&P contract. Guarango 1 is planned to be drilled to a depth of approximately 3,000 feet measured depth and will target potential heavy oil-bearing reservoirs in the Mirador sandstones, the main producing sandstones in the Corporation's Capella heavy oil discovery, and the same porous sandstones encountered in the Achote 1 stratigraphic test.

Middle Magdalena Basin, Colombia

Santa Isabel E&P Contract (100% working interest)
VMM 2 E&P Contract (20% working interest)
VMM 3 E&P Contract (20% back-in right)

The consortium involved in the VMM2 exploration program includes ExxonMobil Exploration Colombia and Vetra Exploracion y Produccion Colombia, the operator of the contract. The Mono Arana 1 well was spud in late September 2012 and will test the oil potential of both the shallow conventional Lisama sandstone reservoir and deeper naturally fractured shale and carbonate reservoirs within the La Luna and Tablazo oil source rocks.

The Lisama reservoir was recently penetrated as anticipated at a depth of approximately 4,800 feet measured depth. Based on Canacol's petrophysical analysis of the open hole logs run across the interval, the Lisama contains approximately 85 feet of potential net oil pay with an average porosity of 21%. The consortium plans to continue drilling the well to a total depth of approximately 12,500 feet measured depth in order to reach the La Luna and Tablazo intervals. The consortium may conduct a number of production tests in La Luna and Tablazo, and afterwards will conduct a production test of the Lisama reservoir to measure flow rate and oil quality unless operating conditions dictate otherwise.

Upon completion of the production testing of the Mono Arana 1 well, the drilling rig is expected to be mobilized to the El Cejudo 1 location to commence drilling of the second exploration well. This well will target the oil potential of shales and carbonates of the La Luna and Tablazo source rocks, and will be drilled to a planned total depth of approximately 14,500 feet measured depth.

The early achievement at VMM 2 has very positive implications for the Corporation's adjacent Santa Isabel E&P contract, where the Corporation has mapped four similar Lisama prospects on the basis of recently acquired 3D seismic. The Corporation plans to drill the largest prospect at Santa Isabel, Oso Pardo, starting in the first quarter of calendar 2013.

Ecuador

Libertador (25% working interest)
Atacapi (25% working interest)

The consortium involved in the Ecuador incremental production contract includes Tecpetrol International S.A., Schlumberger Ltd., and Sertecpet S.A. To date, the Corporation has participated in the drilling of three new development wells and the workover of six existing wells to add new production. For the three months ended September 30, 2012, average incremental production from the fields was 223 bopd, approximately 56 bopd of which is the Corporation's share. The Corporation receives a tariff price of $39.53 per barrel of incremental oil produced. The operator, PetroEcuador, is responsible for all operating expenses related to the incremental production and with that, the Corporation's operating netback in the Ecuador fields equals 100% of its realized tariff price. For the months of October and November, average gross incremental production from the Ecuador fields were 827 bopd and 1,595 bopd, respectively, of which, approximately 207 bopd and 399 bopd are the Corporation's share, respectively. The consortium plans to drill one additional new development well and workover one existing producing well through the remainder of calendar 2012.

Brazil and Guyana

Brazil REC-T-170 (operator, 100% working interest)
Guyana Takutu PPL (operator, 90% working interest)

With the Corporation's strategic move into Ecuador, both Brazil and Guyana are considered non-core. The Corporation is in advanced negotiations with a potential partner to farm-out 50% of its 100% operated working interest in the REC-T-170 block, in exchange for the partner paying 100% of the commitment well costs. The transaction is anticipated to close in calendar fourth quarter 2012.

The Corporation has secured an extension to the Takutu PPL such that one exploration well is drilled by May 22, 2014. The Corporation plans to farm-out all or part of its working interest in the Takutu PPL, with the objective of having a potential partner pay 100% of the commitment well costs in exchange for a portion of the Corporation's working interest in the contract.

Business Combination and Share Consolidation

In October 2012, the Corporation and Shona Energy Company, Inc. ("Shona") jointly announced an agreement ("Arrangement Agreement") whereby the Corporation will acquire 100% of the issued and outstanding class A common shares of Shona ("Shona Common Share") and series A preferred shares of Shona ("Shona Preferred Share"), in exchange for common shares of the Corporation ("Canacol Share") and cash, by way of a statutory plan of arrangement (the "Arrangement"). The transaction is expected to close on or around December 19, 2012, provided all required Shona and Canacol securityholder, court and regulatory approvals are obtained.

Shona, which is listed on the TSX Venture Exchange and OTCQX International, is an international oil and gas exploration and production company with operations focused in Colombia and Peru. With working interests in 5 blocks, Shona has net proven and probable reserves of approximately 95 bcf (15.8 MMboe) and operated production of approximately 14 MMscfpd (2,300 boepd) from the Esperanza E&P contract located in Colombia.

The strategic rationale associated with the acquisition of Shona include:

1) Doubling of the Corporation's 2P reserves plus deemed volumes to 32 million barrels of oil equivalent with a NPV10 of $736 million.
2) Adds long reserve life gas fields to the Corporation's existing portfolio of oil reserves.
3) Adds 2,300 barrels per day of oil equivalent 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 additional capital required.
4) Includes 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 Corporations Capella heavy oil field situated in the Caguan – Putumayo Basin of Colombia.

Description of Shona's Assets:

Esperanza E&P contract (operator, 100% working interest)

Located in the Lower Magdalena basin, the Esperanza Block contains four producing gas fields and is operated under a contract with the Agencia Nacional de Hidrocarburos ("ANH"). According to the NI 51-101 compliant reserves report effective January 1, 2012 by Collarini Associates, the independent auditor assigned 95 bcf in net 2P natural gas reserves (15.8 MMboe) and 78 bcf (13.0 MMboe) in possible reserves to the contract. The four fields are currently producing approximately 14 MMscfpd, the equivalent of 2,300 barrels of oil equivalent per day. The fields' gas is sold under existing long-term gas contracts with an average price of approximately $5.30 per Mscf. As announced on October 10, 2012, Shona has signed a Letter of Intent, and is currently negotiating a Definitive Agreement, to provide up to 17 MMscfpd of gas for an LNG project over 10 years, with a five year extension pending confirmation of reserves as part of a planned calendar 2013 drilling program. The contractual gas price will be determined in the Definitive Agreement, but is expected to be between $4.50 and $5.25 Mscf and including an annual escalation clause. In addition to the producing fields, Shona's seismic programs have identified 12 exploration prospects on the Esperanza Block with up to 300 bcf of net unrisked gas reserves as calculated by Canacol and Shona. The Corporation plans to drill exploration and/or development wells on the concession which will include, in part, some of the larger prospects: Palmer (30 bcf gross unrisked reserves), Nelson Norte (150 bcf gross unrisked reserves), Contento (40 bcf gross unrisked reserves), and Sucre (25 bcf gross unrisked reserves) in calendar 2013.

Serrania E&P contract (37.5% working interest)
Los Picachos E&P contract (37.5% working interest)
Macaya E&P contract (37.5% working interest)

Located in the Caguan-Putumayo basin, the Serrania, Los Picachos, and Macaya exploration contracts are situated immediately to the north and east of the Corporation's Ombu contract, which contains the Capella heavy-oil discovery. Together with the adjacent Cedrela, Portofino, Sangretoro, and Tamarin contracts, Canacol's consolidated exploratory land position of 1.1 million net acres is one of the largest in this emerging conventional heavy-oil trend.

The exploration potential for the Serrania, Los Picachos, and Macaya contracts are characterized by large, faulted anticlines similar to Capella. Serrania is believed to contain one of the largest undrilled 4-way closure structures in northern South America. Cumulatively, management estimates that the contracts contain at least 6 exploratory candidates with over 65 million barrels of net unrisked prospective heavy-oil resources. Canacol aims to utilize its local knowledge acquired at Capella and extensive exploration activity in the area.

Peru block 102 (36.5% working interest)

Block 102 is located in the Maranon Basin of northern Peru. In calendar 2011, Shona participated in a small light oil discovery, Boa Oeste - 1X that is anticipated to be tested by its operating partner later in calendar 2012 or 2013; however, Shona announced on July 27, 2012 that, due to the ongoing testing delays and lack of anticipated benefits from the production test, Shona has elected to be a Non-Consenting Party in the remaining activities on the Boa Prospect. Instead, Shona and the operating partners agreed to enter the fourth exploration period to acquire 400 kilometers of 2D seismic or 133 square kilometers of 3D seismic in 2013, focusing on the anticipated higher-reserve light oil potential along the producing Macusari and Capahuari trends.

Terms of the Arrangement Agreement:

Under the terms of the Arrangement Agreement, each Shona Common Share will be exchanged for C$0.0896 cash and 1.0573 Canacol Share (the "Consideration") and each Shona Preferred Share will be exchanged for $100.00 cash. The Consideration represents a value of approximately C$0.56 per Shona Common Share, based on the volume weighted average price of the Canacol Shares on the Toronto Stock Exchange (the "TSX") for the 15 trading days ended October 12, 2012.

Under the terms of the Arrangement Agreement, all of Shona's outstanding options will be exercised in accordance with their terms or surrendered or otherwise terminated prior to the closing of the Arrangement. In addition, under the terms of the Arrangement Agreement, all holders of Shona warrants will be 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 1.2587 Canacol Shares per Shona Share, and the exercise price of the warrants will be reduced with respect to the exchange ratio of 1.2587 such that the warrants maintain their economic equivalency.

Canacol anticipates issuing to the common shareholders of Shona an aggregate of 246,007,577 pre-consolidation Canacol Shares in connection with the Arrangement, at a deemed purchase price in respect of the Arrangement of C$0.4449. Also, in connection with the Arrangement, Canacol intends to consolidate its common shares on a basis of 1 for 10. After giving effect to the Arrangement and the share consolidation, Canacol is expected to have 86,499,001 post-consolidation Canacol Shares outstanding (864,990,009 pre-consolidation Canacol Shares).

The Arrangement Agreement provides for, among other things, a customary fiduciary out provision, which entitles Shona to consider and accept a superior proposal and a right in favour of Canacol to match any superior proposal. If the Arrangement Agreement is terminated in certain circumstances, including if Shona enters into an agreement with respect to a superior proposal or if the board of directors of Shona withdraws or modifies its recommendation with respect to the proposed transaction, including if Shona exercises its right to terminate the Arrangement Agreement at its sole discretion, Canacol is entitled to a termination payment in cash of $4.0 million. Shona is also entitled to a termination payment in cash of $4.0 million in certain circumstances, including if Canacol exercises its right to terminate the Arrangement Agreement at its sole discretion.

Completion of the transaction is subject to customary closing conditions, including court approval of the Arrangement; approval of two-thirds of the votes cast by holders of Shona Common Shares and Shona Preferred Shares in person or by proxy at the Shona Meeting; approval of a majority of the votes cast by holders of Canacol Shares in person or by proxy at the special meeting of Canacol Shareholders; and applicable government and regulatory approvals.

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, Ecuador and Guyana. 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 CNE.C.

Advisories

The following management's discussion and analysis ("MD&A") is dated November 12, 2012 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 consolidated financial statements of the Corporation for the three months ended September 30, 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 the Shona business combination, will complete its planned capital projects on schedule, and 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 September 30,		**2012**		2011
Cash provided by operating activities	**$**	**10,404**	$	30,136
Changes in non-cash working capital		**3,687**		(12,375)
Funds from operations	**$**	**14,091**	$	17,761

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 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 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.

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, Carbonera and Gacheta.

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 to 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. Sales volumes from these properties are reported in this MD&A net after royalties, the same as NRI oil.

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 in Ecuador; as such, incremental production volumes are reported as tariff production in this MD&A. The operator, PetroEcuador, is responsible for all operating expenses related to the incremental production.

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,	**2012**	2011	Change
Gross production (Rancho Hermoso only)			
Rancho Hermoso – tariff	**2,354**	6,476	(64%)
Rancho Hermoso – non-tariff	**11,708**	13,187	(11%)
	14,062	19,663	(28%)
Production, net after royalties			
Rancho Hermoso – tariff	**2,354**	6,476	(64%)
Rancho Hermoso – non-tariff (NRI)	**2,858**	3,071	(7%)
	5,212	9,547	(45%)
Other Colombia	**474**	203	133%
Ecuador	**56**	-	n/a
Production, net after royalties	**5,742**	9,750	(41%)
Inventory movements and adjustments	**1,180**	160	638%
Sales, net after royalties	**6,922**	9,910	(30%)
Gross sales (Rancho Hermoso only)			
Rancho Hermoso – tariff	**2,361**	6,458	(63%)
Rancho Hermoso – non-tariff	**12,971**	13,326	(3%)
	15,332	19,784	(23%)
Sales, net after royalties			
Rancho Hermoso – tariff	**2,361**	6,458	(63%)
Rancho Hermoso – non-tariff (NRI)	**4,128**	3,255	(27%)
	6,489	9,713	(33%)
Other Colombia	**377**	197	92%
Ecuador	**56**	-	n/a
Sales, net after royalties	**6,922**	9,910	(30%)

The decrease in production volumes at Rancho Hermoso in the first quarter of 2013 compared to 2012 is primarily due to higher than anticipated natural production declines and increased water cuts, thereby limiting production due to water handling capacity. The Corporation also experienced a civil road blockage at the Rancho Hermoso field which caused a temporary shut-in from September 21, 2012 to October 2, 2012. Downtime during the first quarter of fiscal 2013 was 5% in July, 3% in August, and 37% in September, resulting in an overall average downtime of 15% for the quarter.

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 continues to focus on optimizing cash flows from its Rancho Hermoso field with the result that the overall production mix has further shifted from tariff production towards NRI production in the first quarter of 2013. Since the Corporation reports 100% of tariff production volumes and only its proportionate working interest share, after royalties, of NRI production volumes (Q1 2013 – 22.4%), the shift from tariff to NRI production has a pronounced effect on the reported consolidated production volumes; however, operating netbacks for NRI production are significantly higher than for tariff production and therefore have an offset effect on operating cash flows. During the first quarter of fiscal 2013, the Corporation saw a significant reduction in crude oil inventory related to the Rancho Hermoso field due to significant additional sales by the pipeline operator.

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. To date, the Corporation has participated in the drilling of three new development wells and the workover of six existing wells to add new production. For the three months ended September 30, 2012, average gross incremental production from the Ecuador fields was 223 bopd, approximately 56 bopd of which is the Corporation's share. One additional new development well and the workover of one existing producing well are planned throughout the remainder of calendar 2012. The Corporation receives a tariff price of $39.53 per barrel of incremental oil produced. The operator, PetroEcuador, is responsible for all operating expenses related to the incremental production and with that, the Corporation's operating netback in the Ecuador fields equals 100% of its realized tariff price. For the months of October and November, average gross incremental production from the Ecuador fields were 827 bopd and 1,595 bopd, respectively, of which, approximately 207 bopd and 399 bopd are the Corporation's share, respectively.

Crude Oil Sales

Three months ended September 30,	2012	2011	Change
Rancho Hermoso – tariff	$ 3,770	$ 8,877	(58%)
Rancho Hermoso – NRI	36,417	25,284	44%
	40,187	34,161	18%
Other Colombia	1,405	1,169	20%
Ecuador	203	-	n/a
Crude oil sales, net after royalties	$ 41,795	$ 35,330	18%

Crude oil sales are recorded net after royalties. The increase in crude oil sales in the three months ended September 30, 2012 compared to the same period in 2011 is primarily the result of the increased overall realized price of 69%. The increase in overall realized price is also attributable to tariff production contributing a smaller portion to the production/sales mix. In the three months ended September 30, 2012, tariff sales represented 35% of total sales by volume, compared to 65% in the three months ended September 30, 2011.

Average Benchmark and Realized Sales Prices

	Three months ended September 30,		
$/bbl	2012	2011	Change
Brent Crude ("Brent")	$ 109.63	$ 113.24	(3%)
West Texas Intermediate ("WTI")	$ 92.17	$ 89.77	3%
Rancho Hermoso – NRI	$ 95.88	$ 84.43	14%
Other Colombia – NRI	40.46	64.50	(37%)
Total NRI	$ 91.24	$ 83.29	10%
Rancho Hermoso – tariff	$ 17.36	$ 14.94	16%
Ecuador – tariff	39.53	-	n/a
Total tariff	$ 17.87	$ 14.94	20%
Average realized sales price	$ 65.63	$ 38.75	69%

The Corporation's Rancho Hermoso NRI sales prices increased 14% in the first quarter of 2013 compared to the same period in 2012. Overall NRI sales prices in the first quarter of 2013 increased 10% to $91.24/bbl from $83.29/bbl in the comparable period.

Tariff sales are based on contractual amounts. The increase in the realized Rancho Hermoso tariff sales price is the result of an increase in the contractual amount the Corporation received for tariff sales in the first quarter of 2013 compared to the first quarter of 2012. The Corporation expects realized Rancho Hermoso tariff prices to be $17.36/bbl for the remainder of the contract period, which is until August 2018.

Royalties

In Colombia, royalties are taken in kind generally at a rate of 8.0% until net field production reaches 5,000 bopd, then increase on a sliding scale to 20% up to field production of 125,000 bopd. The Corporation's average royalties on NRI production for the three months ended September 30, 2012 was 8.6% compared to 8.8% for the three months ended September 30, 2011. There are no royalties on tariff production.

Operating and Transportation Expenses

Total operating and transportation expenses were as follows:

Three months ended September 30,	2012	2011	Change
Operating expenses	$ 21,732	$ 8,462	157%
Transportation expenses	3,995	4,807	(17%)
Total operating and transportation expenses	$ 25,727	$ 13,269	94%
$/bbl	$ 40.40	$ 14.55	178%

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 each quarter 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 as such costs are incurred at an overall field level.

An analysis of operating expenses is provided below:

Three months ended September 30,	2012	2011	Change
Rancho Hermoso			
Operating expenses	$ 17,960	$ 7,725	132%
Gross sales (Mbbls)	1,411	1,820	(23%)
$/bbl of gross sales	$ 12.73	$ 4.24	200%
Allocated to:			
Rancho Hermoso – tariff	$ 2,045	$ 2,522	(19%)
Rancho Hermoso – NRI	15,915	5,203	206%
	17,960	7,725	132%
Gas purchases and other	3,772	737	412%
Total operating expenses	$ 21,732	$ 8,462	157%
$/bbl			
Rancho Hermoso – tariff	$ 9.42	$ 4.24	122%
Rancho Hermoso – NRI	$ 41.90	$ 17.46	140%
Total operating expenses	$ 34.12	$ 9.28	268%

Operating expenses increased 157% in total and 268% per barrel in the first quarter of 2013 compared to 2012 primarily related to gas plant operations and input gas purchases, increased diesel prices and consumption, as well as increased water handling costs. Further, multiple incidents of injection pump failures occurred during the three months ended September 30, 2012, which resulted in increased repair and maintenance costs as well as increased production downtime during the quarter, as described in more detail in the production volumes section above.

In particular, gas purchases and operating costs with respect to the gas plant accounted for $4.2 million of total operating expenses in the first quarter of fiscal 2013, with the resulting naphtha and LPG production recognized in NRI sales (to the extent it is blended with NRI oil) and liquids sales. Gas plant operations commenced in June 2012 and, consequently, first quarter fiscal 2013 continued to realize start-up costs related to such. In addition, crude oil inventory significantly decreased in the first quarter of fiscal 2013 compared to the fourth quarter of 2012, resulting in higher operating expense being recognized during the quarter compared to the amount being capitalized in inventory at September 30, 2012.

The operational issues are currently being 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 Rancho Hermoso field going forward. All such initiatives are expected to be completed by the end of the first quarter of calendar 2013.

As described above, the Corporation expects Ecuador to increasingly contribute to its production mix in future periods. As the Corporation does not pay operating costs in Ecuador, this change in production mix is expected to have a positive impact on operating expenses per barrel in future periods.
An analysis of transportation expenses is provided below:

Three months ended September 30,		2012		2011	Change
Rancho Hermoso – tariff	$	436	$	1,185	(63%)
Rancho Hermoso – NRI		3,303		3,534	(7%)
Other		256		88	191%
Total transportation expenses	$	3,995	$	4,807	(17%)
$/bbl					
Rancho Hermoso – tariff	$	2.01	$	1.99	1%
Rancho Hermoso – NRI	$	8.70	$	11.80	(26%)
Total transportation expenses	$	6.27	$	5.27	19%

Total transportation expenses have decreased in the three months ended September 30, 2012 compared to the same period in 2011 due to decreased sales volumes and decreased average delivery distances.

As described above, the Corporation expects Ecuador to increasingly contribute to its production mix in future periods. As the Corporation does not pay transportation costs in Ecuador, this change in production mix is expected to have a positive impact on transportation expenses per barrel in future periods.

Operating Netback

Total operating netback is heavily influenced by the sales volume split between tariff and NRI oil. 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. A more meaningful analysis is to examine operating netback by major production category, which is provided after the table below.

	Three months ended September 30,				
$/bbl		**2012**		2011	Change
Crude oil sales, net of royalties, and tariff revenue	$	**65.63**	$	38.75	69%
Operating and transportation expenses		**(40.40)**		(14.55)	178%
Operating netback (see note to reader above)	$	**25.23**	$	24.20	4%

Operating netback by major production category was as follows:

	Three months ended September 30,				
$/bbl		**2012**		2011	Change
Rancho Hermoso – tariff oil					
Tariff revenue	$	**17.36**	$	14.94	16%
Operating and transportation expenses		**(11.43)**		(6.23)	83%
Operating netback	$	**5.93**	$	8.71	(32%)
Rancho Hermoso – NRI oil					
Crude oil sales, net of royalties	$	**95.88**		84.43	14%
Operating and transportation expenses		**(50.60)**		(29.26)	73%
Operating netback	$	**45.28**	$	55.17	(18%)

General and Administrative Expenses

Three months ended September 30,		**2012**		2011	Change
Gross costs	$	**5,205**	$	3,975	31%
Less: capitalized amounts		**(482)**		(1,434)	(66%)
General and administrative expenses	$	**4,723**	$	2,541	86%
$/bbl	$	**7.42**	$	2.79	166%

Gross general and administrative expenses increased 31% in the three months ended September 30, 2012, compared to the same period in 2011, primarily due to an increase in the number of staff to support operations in Colombia.

Net Finance Income and Expense

Three months ended September 30,		**2012**		2011	Change
Fair value adjustment on equity tax payable	$	**34**	$	26	31%
Accretion of decommissioning obligations		**63**		144	(56%)
Net interest and other expense (income)		**114**		(273)	n/a
Net finance expense (income)	$	**211**	$	(103)	n/a

Interest – Interest expense increased in the three months ended September 30, 2012 compared to 2011 due to interest incurred on the credit facility, offset by a combination of lower convertible debenture debt levels and 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 September 30, 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 September 30,	2012	2011
Unrealized change in fair value	$ (3,732)	$ 616
Realized cash settlement	(517)	(79)
Total gain (loss)	$ (4,249)	$ 537

Stock-Based Compensation Expense

Three months ended September 30,	2012	2011	Change
Gross costs	$ 2,074	$ 3,570	(42%)
Less: capitalized amounts	(893)	(1,092)	(18%)
Stock-based compensation expense	$ 1,181	$ 2,478	(52%)

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 September 30,	2012	2011	Change
Depletion and depreciation expense	$ 13,299	$ 8,523	56%
$/bbl	$ 20.88	$ 9.35	123%

Total depletion and depreciation costs have increased in the three months ended September 30, 2012 as compared to the same period in 2011 as a result of significant development costs spent at Rancho Hermoso, thereby increasing the depletable base used for the calculation.

Income Tax Expense

Three months ended September 30,	2012	2011
Current income tax expense (recovery)	$ (885)	$ 3,915
Deferred income tax expense (recovery)	(1,571)	2,760
Income taxes	$ (2,456)	$ 6,675

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 September 30,	2012	2011	Change
Cash provided by operating activities	$ 10,404	$ 30,136	(65%)
Funds from operations	14,091	17,761	(21%)
Per share – basic and diluted ($)	0.02	0.03	(30%)
Net income (loss)	(6,214)	13,486	n/a
Per share – basic and diluted ($)	(0.01)	0.03	n/a

Capital Expenditures

Three months ended September 30,	2012	2011
Drilling and completions	$ 5,554	$ 15,195
Facilities and infrastructure	2,862	9,104
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other	10,515	7,057
Total capital expenditures	$ 18,931	$ 31,356
Recorded as:		
Expenditures on exploration and evaluation assets	$ 4,781	$ 6,723
Expenditures on property, plant and equipment	$ 14,150	$ 24,633

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

- Recompletion, seismic and facility costs at the Rancho Hermoso field;
- Drilling, completion and facility costs at the Capella field (non-operated);
- Geology and seismic costs at LLA 23, Cedrela and Portofino;
- Civil works and drilling costs at Achote 1 in Portofino; and
- Drilling, completion and recompletion costs at the Ecuador fields.

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, 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. 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.

	For the Three months ended September 30, 2012	For the year ended June 30, 2012
Bank debt (current and long-term) – principal	$ **44,000**	$ 30,000
Convertible debentures – principal	**25,942**	25,519
Working capital surplus, excluding the current portion of bank debt, convertible debentures, and derivatives	**(33,742)**	(29,697)
Net debt (surplus)	**36,200**	25,822
Annualized funds from operations	$ **56,364**	$ 68,965
Net debt to funds from operations	**0.6**	0.4

Credit Facilities and Debt

The Corporation, through its wholly-owned subsidiary, Canacol Energy Colombia S.A. ("Canacol Colombia"), has entered into an agreement for a total credit facility of $200.0 million with an approved $85.0 million borrowing base at September 30, 2012. The credit facility includes a reserve-based revolving facility of $55.0 million and a term facility of $30.0 million.

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% - 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 payments plus accrued interests due at the end of each three month period starting on September 1, 2012.

The combined credit facility is secured by the Corporation's oil and gas assets and reserves. At September 30, 2012, $44.0 million was drawn under the combined credit facility. The borrowing base is currently under review by the lender as required under the lending agreement.

In addition to the above, the Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $21.2 million (COP$ 38.1 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. At September 30, 2012, no amounts were drawn under the facilities.

At September 30, 2012, the Corporation had letters of credit outstanding totalling $19.8 million to guarantee work commitments on exploration blocks. The total of these letters of credit reduce the amounts available under the Colombian revolving lines of credit described above.

The Corporation has convertible debentures outstanding with a face value of $25.9 million (fair value – $26.1 million) 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$1.0526 per share. The debentures are redeemable in either cash or shares of the Corporation at any time subsequent to June 30, 2013.

Share Capital

At November 12, 2012, the Corporation had 619.0 million common shares, 3.3 million warrants and 58.5 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 September 30, 2012:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	12,000	15,000	17,000	44,000
Trade and other payables	37,777	-	-	37,777
Deferred income	2,500	-	-	2,500
Commodity contracts	3,600	559	-	4,159
Equity tax payable – undiscounted	1,224	1,224	-	2,448
Convertible debentures – principal	-	-	25,942	25,942
Convertible debentures – interest	2,000	4,000	-	6,000
Warrants	-	80	500	580
Exploration contracts (see below)	17,925	31,923	-	49,848
Incremental production contract (Ecuador)	24,670	48,700	10,170	83,540
Office leases	1,131	1,823	5,850	8,804
	102,827	103,309	59,462	265,598

Exploration Contracts

The Corporation has entered into a number of exploration 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 exploration commitments at September 30, 2012 of $49.8 million and has issued $19.8 million in financial guarantees related thereto.

Colombia

The Corporation has remaining net work program and farm-in commitments totalling approximately $47.0 million, of which $16.2 million are due within a year. These commitments are planned to be satisfied by means of seismic work and exploration drilling.

Brazil

The Corporation has a net work program commitment on block 170 in the Reconcavo basin to be satisfied by means of drilling one exploration well in 2012 or early 2013. The Corporation is in advanced negotiations with a potential partner to farm-out 50% of its 100% operated working interest in the REC-T-170 block, with the transaction anticipated to close in calendar fourth quarter 2012.

Guyana

The Corporation has a net work program commitment in Guyana to be satisfied by means of drilling one exploration well. The Corporation has recently secured an extension to the Takutu PPL such that the deadline for the drilling of the exploration well was extended to May 22, 2014. The Corporation plans to farm-out all or part of its working interest in the Takutu PPL in 2012 and is currently reviewing bids from interested parties.

Ecuador

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

Subsequent to September 30, 2012, the Corporation has entered into an agreement (the "Arrangement Agreement") whereby the Corporation will acquire 100% of the issued and outstanding class "A" common shares of Shona Energy Company, Inc. ("Shona Common Shares") and series "A" preferred shares of Shona Energy Company, Inc. ("Shona Preferred Shares"), in exchange for common shares of the Corporation ("Canacol Shares") and cash, by way of a statutory plan of arrangement (the "Arrangement"). The transaction is expected to close on or around December 19, 2012, provided all required Shona Energy Company, Inc. ("Shona") and Canacol securityholder, court and regulatory approvals are obtained.

Under the terms of the Arrangement, each Shona Common Share will be exchanged for C$0.0896 cash and 1.0573 Canacol Share (the "Consideration") and each Shona Preferred Share will be exchanged for $100.00 cash. The Consideration represents a value of approximately C$0.56 per Shona Common Share, based on the volume weighted average price of the Canacol Shares on the Toronto Stock Exchange (the "TSX") for the 15 trading days ended October 12, 2012.

Under the terms of the Arrangement Agreement, all of Shona's outstanding options will be exercised in accordance with their terms or surrendered or otherwise terminated prior to the closing of the Arrangement. In addition, under the terms of the Arrangement Agreement, all holders of Shona warrants will be 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 1.2587 Canacol Shares per Shona Share, and the exercise price of the warrants will be reduced with respect to the exchange ratio of 1.2587 such that the warrants maintain their economic equivalency.

The Arrangement Agreement provides for, among other things, a customary "fiduciary out" provision, that entitles Shona to consider and accept a superior proposal and a right in favour of Canacol to match any superior proposal. If the Arrangement Agreement is terminated in certain circumstances, including if Shona enters into an agreement with respect to a superior proposal or if the board of directors of Shona withdraws or modifies its recommendation with respect to the proposed transaction, including if Shona exercises its right to terminate the Arrangement Agreement at its sole discretion, Canacol is entitled to a termination payment in cash of $4.0 million. Shona is also entitled to a termination payment in cash of $4.0 million in certain circumstances, including if Canacol exercises its right to terminate the Arrangement Agreement at its sole discretion.

OUTLOOK

For the remainder of calendar 2012 and the first quarter of calendar 2013, the primary focus of the Corporation will be on the successful closing of the Shona acquisition, as well as the execution of its capital program, including:

- The completion of the drilling of its first light oil exploration well on the LLA-23 block, immediately to the north of the Rancho Hermoso field, to test the Labrador prospect. The well commenced drilling in late October 2012.
- The completion of drilling of the Guarango 1 stratigraphic well on the Cedrela block, targeting potential heavy oil-bearing reservoirs in the Mirador sandstones. The well commenced drilling in late October 2012.
- The completion of the ongoing acquisition of 45 square kms of 3D seismic and 58 km of 2D seismic in the southern part of the Portofino block, with plans to use the data to drill 3 remaining stratigraphic wells in calendar 2012 and extending into calendar first quarter 2013.
- The completion of drilling and production testing of the non-operated Mono Arana 1 well on the VMM 2 block, which is currently underway. The Mono Arana 1 well has already encountered 85 feet of potential net oil pay within the Lisama sandstone reservoir, which the Corporation plans to production test.
- Following the Mono Arana 1 well, the drilling of a second non-operated exploration well on the VMM 2 block, El Cejudo 1, commencing in late 2012 and specifically targeting non-conventional fractured shale reservoirs in the Cretaceous La Luna and Tablazo oil source rocks.
- The drilling of one additional new development well and the workover of one existing producing well before the end of calendar 2012 under its non-operated incremental production contract for the Libertador and Atacapi mature producing oil fields in Ecuador. Starting in September 2012, these Ecuador fields have begun providing incremental production to the Corporation and are expected to see significant increased production in future periods as the development program is executed. Based on the current development program, the Corporation expects incremental production to peak through 2013 and 2014.

SUMMARY OF QUARTERLY RESULTS

	2013	2012				2011		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial								
Crude oil sales	**37,822**	34,748	34,481	40,941	26,453	37,339	23,452	15,669
Tariff revenue	**3,973**	10,954	14,151	14,300	8,877	9,676	8,677	1,212
Total revenues	**41,795**	45,702	48,632	55,241	35,330	47,015	32,129	16,881
Funds from operations (1)	**14,091**	9,645	20,042	24,480	17,761	17,515	18,024	1,829
Per share – basic and diluted ($)	**0.02**	0.02	0.03	0.05	0.03	0.03	0.04	-
Net income (loss)	**(6,214)**	3,830	3,663	(2,423)	13,486	18,407	(852)	(14,918)
Per share – basic and diluted ($)	**(0.01)**	0.01	0.01	-	0.03	0.04	-	(0.03)
Capital expenditures	**18,931**	39,927	52,424	62,425	31,356	24,661	20,665	22,403
Operations								
Tariff oil production (bopd)	**2,410**	6,931	8,917	8,971	6,476	7,652	7,023	980
NRI oil production (bopd)	**3,332**	3,411	4,246	4,422	3,274	3,796	2,935	2,347
Total oil production (bopd)	**5,742**	10,342	13,163	13,393	9,750	11,448	9,958	3,327

(1) Non-IFRS measure – see "Non-IFRS Measures" section.

RISKS AND UNCERTAINTIES

There have been no significant changes in the three months ended September 30, 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. 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 the design of the Corporation's DC&P as at September 30, 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 the design effectiveness of the Corporation's ICFR as at September 30, 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 September 30, 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.

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.