CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE AND SIX MONTHS ENDED DECEMBER 31, 2011

CANACOL ENERGY LTD.

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,		
	2011	2010	Change	**2011**	2010	Change
Crude oil sales, net of royalties	**40,941**	15,669	161%	**67,394**	30,888	118%
Tariff revenue	**14,300**	1,212	1,080%	**23,177**	2,791	730%
Total revenues	**55,241**	16,881	227%	**90,571**	33,679	169%
Funds from operations (1)	**24,480**	2,579	849%	**42,241**	10,345	308%
Per share – basic and diluted ($)	**0.05**	0.01	400%	**0.08**	0.02	300%
Net income (loss)	**(2,423)**	(14,918)	(84%)	**11,063**	(44,986)	n/a
Per share – basic and diluted ($)	**-**	(0.03)	(100%)	**0.02**	(0.10)	n/a
Capital expenditures	**62,425**	22,403	179%	**93,781**	30,644	206%
				December 31, 2011	June 30, 2011	Change
Cash and cash equivalents				**81,023**	101,627	(20%)
Restricted cash				**9,643**	13,048	(26%)
Net working capital surplus (1)				**67,979**	94,547	(28%)
Total assets				**410,481**	316,570	30%
Common shares, end of period (000s)				**613,286**	511,637	20%

Operating	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Crude oil production (bopd)						
Tariff	**8,971**	980	815%	**7,724**	1,120	590%
NRI	**4,422**	2,347	88%	**3,848**	2,038	89%
Total	**13,393**	3,327	303%	**11,572**	3,158	266%
Crude oil sales (bopd)						
Tariff	**8,954**	950	842%	**7,706**	1,102	599%
NRI	**4,726**	2,231	112%	**4,089**	2,325	76%
Total	**13,680**	3,181	330%	**11,795**	3,427	244%
Rancho Hermoso – tariff oil operating netback ($/bbl) (1)						
Realized tariff oil price	**17.36**	13.87	25%	**16.35**	13.76	19%
Operating and transportation costs	**(7.30)**	(4.41)	66%	**(6.85)**	(6.70)	2%
RH tariff oil operating netback	**10.06**	9.46	6%	**9.50**	7.06	34%
Rancho Hermoso – non-tariff (NRI) oil operating netback ($/bbl) (1)						
Realized crude oil price, net of royalties	**95.07**	77.90	22%	**90.63**	73.26	24%
Operating and transportation costs	**(36.63)**	(24.60)	49%	**(33.52)**	(25.62)	31%
RH NRI oil operating netback	**58.44**	53.30	10%	**57.11**	47.64	20%

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

Financial Highlights for the Three and Six Months Ended December 31, 2011

Canacol Energy Ltd. ("Canacol" or the "Corporation") completed a successful quarter in fiscal Q2 2012. Highlights include:

- Total revenues for the three months ended December 31, 2011 increased 227% to $55.2 million from $16.9 million for the comparable period. Total revenues for the six months ended December 31, 2011 increased 169% to $90.6 million from $33.7 million for the comparable period.
- Funds from operations for the three months ended December 31, 2011 increased 849% to $24.5 million from $2.6 million for the comparable period. Funds from operations for the six months ended December 31, 2011 increased 308% to $42.2 million from $10.3 million for the comparable period.
- Net loss for the three months ended December 31, 2011 was $2.4 million, compared to a net loss of $14.9 million for the comparable period. Net income for the six months ended December 31, 2011 was $ 11.1 million, compared to a net loss of $45.0 million for the comparable period. The net loss for the three months ended December 31, 2011 was primarily driven by the realization of non-cash deferred tax assets during the period.
- Capital expenditures for the three and six months ended December 31, 2011 were $62.4 million and $93.8 million, respectively.
- Average daily sales volumes increased 330% to 13,680 barrels of oil per day ("bopd") for the three months ended December 31, 2011 compared to 3,181 bopd for the comparable period. For the six months ended December 31, 2011, average daily sales volumes increased 244% to 11,795 bopd compared to 3,427 bopd for the comparable period.
- For the three months ended December 31, 2011, the Corporation's operating netback for Rancho Hermoso non-tariff (NRI) production was $58.44/bbl and for Rancho Hermoso tariff production was $10.06/bbl. For the six months ended December 31, 2011, the Corporation's operating netbacks were $57.11/bbl for Rancho Hermoso non-tariff (NRI) production and $9.50/bbl for Rancho Hermoso tariff production.
- The Corporation's balance sheet remains strong with $90.7 million in cash, cash equivalents and restricted cash, and $68.0 million of working capital surplus at December 31, 2011. The Corporation remains fully funded to execute its calendar 2012 production and exploration programs.

OPERATIONAL UPDATE

Production

In late December 2011, the Corporation recorded its highest production ever with production from the Rancho Hermoso, Entrerrios and Capella fields, all located in Colombia, of 19,173 bopd net after royalties, significantly above the corporate guidance exit rate target of 14,000 bopd set for calendar 2011.

Corporate net production for the month of January 2012 averaged 15,456 bopd, which consisted of 4,190 bopd of non-tariff production and 11,266bopd of tariff production.

Capital Program and Corporate Guidance for Calendar 2012

In late December 2011, the Corporation announced its calendar 2012 capital program of $150 million for exploration and development activities in Colombia, Brazil and Guyana. The budget includes the drilling of 40 gross wells (16 net wells), which consists of 26 gross development wells and 14 gross exploration wells. The budget also includes the acquisition of 740 kilometers and 361 square km of 2D and 3D seismic, respectively, and the expansion of facilities at the Corporation's operated Rancho Hermoso field. In total, the Corporation plans to spend approximately $88 million for exploration programs in Colombia, Brazil and Guyana, and $62 million for production programs in Colombia in calendar 2012. The budget meets the Corporation's exploration drilling and seismic acquisition work program commitments for calendar 2012. In February 2012, the Corporation announced its participation in an incremental production contract on the Libertador and Atacapi fields in Ecuador. As a result, the Corporation expects to incur approximately $10.2 million of additional capital expenditures with respect to this contract in calendar 2012.

The Corporation's production guidance for calendar 2012 is expected to average between 14,000 and 16,000 bopd, net after royalties. This guidance excludes any production from potential future exploration successes or from the incremental production contract on the Libertador and Atacapi fields in Ecuador.

Corporate Acquisition

On November 29, 2011, the Corporation acquired 96% of the common shares of Carrao Energy Ltd. ("Carrao"), and closed on the remaining 4% of the common shares on January 30, 2012 pursuant to the compulsory acquisition provisions of the *Business Corporations Act* (British Columbia). The transaction provides Canacol with a suite of exploration assets located in the Llanos, Caguan, and Middle Magdalena basins in Colombia.

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

Llanos Basin, Colombia

Rancho Hermoso Field (operator, 100% working interest)

In December 2011, the Corporation completed the drilling and casing of the Rancho Hermoso 13 ("RH 13"). The well was drilled to a total depth of 10,500 feet measured depth *("ft md")* in the Ubaque reservoir. Petrophysical analysis of the open-hole logs indicated a total of 110 ft of oil pay within the well: 5 ft of oil pay within the C7 reservoir with average porosity of 20%, 26 ft of oil pay in the Mirador reservoir with average porosity of 25%, 8 ft of pay within the Los Cuervos–Barco reservoir with average porosity of 20%, 15 ft of oil pay within the Guadalupe reservoir with average porosity of 23%, and 56 ft of oil pay within the Ubaque reservoir with average porosity of 20%. In late December 2011, RH 13 was placed on permanent production at a stable gross rate of approximately 10,164 bopd (2,541 bopd net to Canacol).

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

For calendar 2012, Canacol plans to spend $44 million on drilling, seismic and facilities expansion at Rancho Hermoso field. Following the strong development drilling program in 2011, the Corporation plans to begin 2012 with the drilling of four consecutive development wells (RH 14, RH 15, RH 16, and RH 17). In addition to the new wells, Canacol intends to acquire 37 square kilometers of 3D seismic to further define the Barco and Carbonera reservoir channels within the field for potential future drilling. The Corporation intends to expand Rancho Hermoso's existing facilities to process additional fluids and incur various construction costs for completion of the gas plant facility, which is anticipated to come online in February 2012.

LLA 23 E&P Contract (80% working interest)
LLA 10 E&P Contract (39% working interest)
Caño Los Totumos E&P Contract (51% working interest)
Morichito E&P Contract (15% working interest)
Entrerrios Production Contract (operator, 60% working interest)

For calendar 2012, the Corporation plans to re-enter the Agueda 1 well on the LLA 23 contracts, as well as drilling three light oil exploration wells and acquiring seismic on the Caño Los Totumos, LLA 10 and LLA 23 contracts. Commencing early in 2012, Canacol plans to acquire 249 square kilometers of 3D seismic on the LLA 23, Caño Los Totumos and Morichito exploration blocks. In the second half of calendar 2012, the Corporation plans to drill one exploration well on each of the three blocks. In February 2012, the Corporation purchased an additional 9% working interest in the LLA 23 Contract for $2.5 million, thereby increasing its current working interest to 80%. In calendar Q1 2012, the Corporation plans to re-enter that Agueda 1 well and test 47 feet of bypassed oil pay that it has identified within the C7 sandstone reservoir, which is productive three kilometers to the south at the Rancho Hermoso field. The

Corporation also plans to dispose of part or all of its working interests in the Caño Los Totumos, LLA 10 and Morochito E&P Contracts, along with its interest in the Entrerrios Production Contract, which are all considered immaterial to its portfolio. A sales package is currently being assembled and the Corporation anticipates disposing of the assets by the end of calendar Q2 2012.

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)

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

For calendar 2012, the Corporation intends to fund its share of the drilling and completion of 22 new horizontal and vertical production wells on its Capella discovery located on the Ombu E&P contract. In addition, Canacol plans on drilling four consecutive exploration wells and the acquisition of 380 km of 2D seismic on Cedrela, Portofino and Sangretoro.

Andaquies E&P Contract (36% working interest)
Coati E&P Contract (40% working interest)

In February 2012, the Corporation announced that the operator had finished the completion and testing of the Neme formation in the Cachalote-1 well in Colombia and will abandon the well. The Cachalote-1 well encountered 271 feet of Neme sandstone that contained oil shows over an interval of approximately 130 feet with average porosity of 21%. The Neme reservoir was perforated in the intervals from 5,676 to 5,718 ft md and from 5,642 to 5,660 ft md and on a swab test flowed from the lower perforations traces of oil with a gravity of 13.8° API and fresh water at rate of 1,280 barrels per day ("bwpd"). The upper perforations tested traces of oil and 1,020 bwpd.

The data collected from the test of Cachalote-1 indicates that the oil recovered from these excellent reservoirs most likely represents a residual oil accumulation in a structure that has been either breached or flushed by fresh water. The Cachalote-1 well is the first exploration well on the Andaquies block (114,875 gross acres) located in the northern Putumayo Basin in Colombia.

For calendar 2012, the Corporation intends to participate in the drilling of two exploration wells, one additional well on the Andaquies E&P Contract in the calendar first quarter of 2012, and one on the Coati E&P contract later in 2012. The Corporation will also participate in the acquisition of 100 km of 2D seismic and 75 square km of 3D seismic on the Andaquies and Coati blocks in calendar 2012.

Middle Magdalena Basin, Colombia

Santa Isabel E&P Contract (100% working interest)
VMM 2 E&P Contract (40% working interest)
VMM 3 E&P Contract (20% working interest)

In February 2012, the Corporation purchased the remaining 10% working interest in the Santa Isabel E&P Contract from its partner for $2.0 million, bringing its working interest up to 100%. In the first half of calendar 2012, the Corporation plans on drilling two exploration wells on the Santa Isabel and VMM 2 contracts targeting conventional sandstone reservoirs which are productive in nearby producing fields. For VMM 3, Canacol has the rights to acquire its 20% undivided interest, at no cost, upon fulfillment of certain conditions described in the agreement between it and a world-class operating partner. The operating partner plans to invest up to $55 million over the next two years through the acquisition of 3D seismic and the drilling of three wells to test a prospective Cretaceous oil-shale play on the block. While participating in the upside at VMM 3, the Corporation aims to capture proprietary information to de-risk its higher working interest in the adjacent Santa Isabel and VMM 2 blocks. The Corporation recently engaged GLJ Consultants to prepare a prospective resource report for these three blocks.

Upper Magdalena Basin, Colombia

COR-11 E&P Contract (operator, 70% working interest)
COR-39 E&P Contract (operator, 70% working interest)

For calendar 2012, the Corporation plans on the acquisition of 260 km of 2D seismic followed by drilling of each of the contracts in 2013.

Brazil and Guyana

Brazil REC-T-170 (operator, 100% working interest)
Guyana Takutu PPL (operator, 70% working interest)

In the first half of calendar 2012, the Corporation plans to drill one light oil exploration well each at REC-T-170 and Takutu PPL in the Reconcavo basin, Brazil and Takutu basin, Guyana, respectively. With the recent move into Ecuador, both Brazil and Guyana are considered non-core to the Corporation. Canacol is in advanced negotiations with a potential partner to farmout 50% of its 100% operated working interest in the REC 170 block, with the transaction anticipated to close prior to the end of calendar Q1 2012. The Corporation also plans to farmout all or part of its working interest in the Takutu PPL in 2012 and is currently assembling a farmout package to be sent to interested parties.

Ecuador

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

In February 2012, PARDALISERVICES S.A., a company established by Tecpetrol International S.A. (the "Operator"), Schlumberger Ltd., Sertecpet S.A., and Canacol 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 Corporation has a non-operated 25% equity participation in the project.

The Operator is required to spend a total of $334 million ($92.9 million, net to Canacol) for the drilling of 31 new development wells and the workover of 28 existing wells over the 15 year period of the contract. In return for increased production at EPPE's mature fields, the Operator will receive a fixed price tariff of $39.56 for each incremental barrel produced, which is insensitive to oil price fluctuations.

In addition to absorbing all operating costs at the Libertador and Atacapi fields, EPPE will continue to manage regular operations, licensing and permits, and relations with communities and the local government. The Operator will supervise base curve production and assist EPPE with potentially reducing operating expenses at both fields. The value of any success achieved will be split 50/50 between EPPE and the Contractor.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. (the "Corporation") and its subsidiaries are primarily engaged in petroleum and natural gas exploration and development activities in Colombia, Brazil and Guyana. The Corporation's head office is located at 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 February 8, 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 condensed consolidated financial statements of the Corporation for the three and six months ended December 31, 2011 and 2010 (the "interim financial statements"), and the audited consolidated financial statements and management's discussion and analysis for the year ended June 30, 2011. In 2010, the CICA Handbook was revised to incorporate International Financial Reporting Standards ("IFRS") and requires publicly accountable enterprises to apply such standards effective for years beginning on or after January 1, 2011. Previously, the Corporation prepared its interim and annual consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). The interim financial statements have been prepared in accordance with IFRS and all amounts herein are in United States dollars, unless otherwise noted, and all tabular amounts are in thousands of United States dollars, except per share amounts or as otherwise noted. Additional information for the Corporation, including the annual information form, may be found on SEDAR at www.sedar.com.

Forward-Looking Statements *– Certain information set forth in this document contains forward-looking statements. All statements other than historical fact contained herein are forward-looking statements, including, without limitation, statements regarding the future financial position, business strategy, production rates, and plans and objectives of or involving the Corporation. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. In particular with respect to forward-looking comments in this MD&A, readers are cautioned that there can be no assurance that the Corporation will complete its planned capital projects on schedule, 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, and that it will secure the increase in its term loan for the construction of the gas liquids separation facility at Rancho Hermoso. 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 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,	
	2011	2010	**2011**	2010
Cash provided by operating activities	**$ 35,758**	$ 15,394	**$ 65,894**	$ 17,885
Changes in non-cash working capital	**(11,278)**	(12,815)	**(23,653)**	(7,540)
Funds from operations	**$ 24,480**	$ 2,579	**$ 42,241**	$ 10,345

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

IFRS

The accounting policies of the Corporation have been adjusted to comply with IFRS beginning with the balance sheet as at July 1, 2010. A comprehensive summary of all of the significant changes, including reconciliations of Canadian GAAP financial statements to those prepared under IFRS, is presented in note 24 "Transition to IFRS" of the Corporation's interim financial statements as at and for the three and six months ended December 31, 2011.

The adoption of IFRS did not impact the cash the Corporation generated; however, it did have an impact on the Corporation's statement of financial position and statement of operations and comprehensive income (loss). A reconciliation of the previously reported net loss for the three and six months ended December 31, 2010, from Canadian GAAP to IFRS is provided below:

	Three months ended December 31, 2010	Six months ended December 31, 2010
Net loss under Canadian GAAP, as previously reported	$ 13,835	$ 16,437
Depletion and depreciation	(2,689)	(4,158)
Income tax expense	485	515
Net finance (income) expense	(78)	2,686
Impairment loss on Brazilian assets	(9,673)	2,069
Loss on convertible debentures	13,152	27,637
Stock-based compensation	(114)	(200)
Net loss under IFRS	$ 14,918	$ 44,986

RESULTS OF OPERATIONS

Overview

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

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

The Corporation also has minor production from its Capella and Entrerrios properties in Colombia. Sales volumes from these properties are reported in this MD&A net after royalties, the same as NRI oil.

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

Business Acquisition

In November 2011, the Corporation entered into an agreement to acquire all of the issued and outstanding shares of Carrao Energy Ltd. ("Carrao"), a private company engaged in the evaluation, acquisition, exploration and development of oil and gas properties in Colombia.

On November 29, 2011, the closing date of the transaction, the Corporation acquired approximately 96% of the issued and outstanding securities of Carrao through the issuance of an aggregate 99,930,109 common shares of the Corporation to former holders of Carrao shares, warrants and stock options. The closing price of the Corporation's common shares on the closing date was C$0.64 per share. On January 30, 2012, the Corporation issued a further 4,806,445 common shares to acquire the remaining 4% interest in accordance with the compulsory acquisition provisions of the *Business Corporations Act* (British Columbia).

Holders of certain options to purchase Carrao shares elected to convert their Carrao options into options to purchase 5,795,110 common shares of the Corporation. The options were fair-valued at $0.39 per option using a Black-Scholes model. Certain warrants exercisable into Carrao shares were also exchanged for warrants exercisable into 3,286,920 common shares of the Corporation. The warrants were also fair-valued at $0.39 per warrant using a Black-Scholes model.

The President, Chief Executive Officer and Director of the Corporation, Mr. Charle Gamba, was also an independent director of Carrao at the time of the acquisition (holding less than 1% of the common shares of Carrao). During the acquisition process, the Corporation and Carrao each struck special committees of their respective boards which excluded Mr. Gamba. Mr. Gamba had no involvement in the formulation, negotiation or acceptance of the offer to acquire Carrao either in his capacity as President, Chief Executive Officer and Director of the Corporation, or as an independent director of Carrao.

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 periods ending December 31, 2011.

The acquisition has been accounted for using the purchase method with the results of Carrao's operations included in the Corporation's financial and operating results commencing November 30, 2011. The allocation of net assets acquired was based on the best available information at the time and could be subject to further change. The preliminary allocation of the purchase price based on estimated fair values was as follows:

Consideration:		
Issue common shares, options and warrants	$	65,544
Non-controlling interest		3,047
Share issue costs		(127)
	$	**68,464**
Net assets acquired:		
Current assets	$	13,281
Exploration and evaluation assets		70,917
Current liabilities		(2,191)
Future income tax liability		(13,543)
	$	**68,464**

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

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Gross production (Rancho Hermoso only)						
Rancho Hermoso – tariff	**8,971**	980	815%	**7,724**	1,120	590%
Rancho Hermoso – non-tariff	**17,140**	9,205	86%	**15,164**	7,839	93%
	26,111	10,185	156%	**22,888**	8,959	155%
Production, net after royalties						
Rancho Hermoso – tariff	**8,971**	980	815%	**7,724**	1,120	590%
Rancho Hermoso – non-tariff (NRI)	**4,247**	2,139	99%	**3,659**	1,829	100%
	13,218	3,119	324%	**11,383**	2,949	286%
Other	**175**	208	(16%)	**189**	209	(10%)
Production, net after royalties	**13,393**	3,327	303%	**11,572**	3,158	266%
Inventory movements and adjustments	**288**	(145)	(299%)	**224**	269	(17%)
Sales, net after royalties	**13,681**	3,182	330%	**11,796**	3,427	244%
Gross sales (Rancho Hermoso only)						
Rancho Hermoso – tariff	**8,954**	950	843%	**7,706**	1,102	599%
Rancho Hermoso – non-tariff	**17,585**	8,106	117%	**15,456**	7,639	102%
	26,539	9,056	193%	**23,162**	8,741	165%
Sales, net after royalties						
Rancho Hermoso – tariff	**8,954**	950	842%	**7,706**	1,102	599%
Rancho Hermoso – non-tariff (NRI)	**4,551**	2,014	126%	**3,903**	2,117	84%
	13,505	2,964	356%	**11,609**	3,219	261%
Other	**175**	217	(19%)	**186**	208	(11%)
Sales, net after royalties	**13,680**	3,181	330%	**11,795**	3,427	244%

The increase in production at Rancho Hermoso reflects the Corporation's continued success with its development drilling program, offset by natural production declines. This drilling program has resulted in the Corporation producing from 14 wells in Q2 2012 compared to 10 wells in Q2 2011.

Rancho Hermoso tariff production increased 815% from Q2 2011 to Q2 2012 and 590% from H1 2011 to H1 2012, primarily due to production from RH 8 and RH 9. RH 8 initially came on production from the Barco Los Cuervos formation but was converted to a Mirador well and commenced production in October 2011 at an initial rate of approximately 4,200 bopd. RH 9 came on production in December 2010 at an initial rate of approximately 6,500 bopd and therefore did not contribute to a full quarter or half-year of production in the comparable prior periods.

Rancho Hermoso NRI production increased 99% from Q2 2011 to Q2 2012 primarily due to the successful drilling of RH 11, RH 12 and RH 13, which came on production in September 2011, October 2011 and December 2011, respectively, at combined initial rates of approximately 8,000 bopd. Similarly, Rancho Hermoso NRI production increased 100% from H1 2011 to H1 2012 for the reasons described above, as well as due to the successful drilling of RH 7, RH 8 and RH 10, which came on production in October 2010, December 2010 and February 2011, respectively, at combined initial rates of approximately 9,300 bopd.

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

Crude Oil Sales

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Rancho Hermoso – tariff	**$ 14,300**	$ 1,212	1,080%	**$ 23,177**	$ 2,791	730%
Rancho Hermoso – NRI	**39,805**	14,434	176%	**65,089**	28,536	128%
	54,105	15,646	246%	**88,266**	31,327	182%
Other	**1,136**	1,235	(8%)	**2,305**	2,352	(2%)
Crude oil sales, net after royalties	**$ 55,241**	$ 16,881	227%	**$ 90,571**	$ 33,679	169%

Crude oil sales are recorded net after royalties. The increase in crude oil sales from Q2 2011 to Q2 2012 and H1 2011 to H1 2012, respectively, is primarily the result of increased overall sales of 330% and 244%, respectively, offset by a decrease in overall realized prices resulting from tariff production contributing a greater portion to the production mix. In both Q2 2012 and H1 2012, tariff sales represented 65% of total sales by volume compared to only 30% and 32% in Q2 2011 and H1 2011, respectively.

Average Benchmark and Realized Sales Prices

$/bbl	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Brent Crude ("Brent")	**$ 108.92**	$ 87.34	25%	**$ 110.45**	$ 82.17	34%
West Texas Intermediate ("WTI")	**$ 94.02**	$ 85.16	10%	**$ 91.74**	$ 80.16	14%
Rancho Hermoso – NRI	**$ 95.07**	$ 77.90	22%	**$ 90.63**	73.26	24%
Other	**70.56**	61.86	14%	**67.35**	61.45	10%
Total NRI	**94.16**	76.34	23%	**89.57**	72.20	24%
Rancho Hermoso – tariff	**17.36**	13.87	25%	**16.35**	13.76	19%
Average realized sales price	**$ 43.89**	$ 57.68	(24%)	**$ 41.73**	$ 53.41	(22%)

The Corporation's Rancho Hermoso NRI sales prices increased 22% in Q2 2012 compared to Q2 2011 and 24% in H1 2012 compared to H1 2011. Overall NRI sales prices also increased 23% in Q2 2012 to $94.16/bbl from $76.34/bbl in Q2 2011, while H1 2012 NRI sales prices increased 24% to $89.57/bbl from $72.20/bbl in H1 2011, above WTI increases in the comparative periods.

Tariff sales are based on contractual amounts. The increase in realized tariff sales is the result of an increase in the contractual amount the Corporation received for tariff sales in Q2 2012 compared to Q2 2011, and H1 2012 compared to H1 2010. The Corporation expects realized 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% 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 Q2 2012 and H1 2012 were 9.2% and 8.7%, respectively, compared to 8.0% and 8.0%, respectively, for Q2 2011 and H1 2011. There are no royalties on tariff production.

The Corporation records crude oil sales net of royalties.

Operating and Transportation Expenses

Total operating and transportation expenses were as follows:

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Operating expenses	**$ 15,689**	$ 4,761	230%	**$ 24,151**	$ 11,058	118%
Transportation expenses	**7,884**	1,684	368%	**12,691**	2,721	366%
Total operating and transportation expenses	**$ 23,573**	$ 6,445	266%	**$ 36,842**	$ 13,779	167%
$/bbl	**$ 18.73**	$ 22.02	(15%)	**$ 16.98**	$ 21.85	(22%)

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.

An analysis of operating expenses is provided below:

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Rancho Hermoso						
Operating expenses	**$ 14,130**	$ 3,564	296%	**$ 21,855**	$ 9,114	140%
Gross sales (Mbbls)	**2,442**	833	193%	**4,262**	1,608	165%
$/bbl of gross sales	**$ 5.79**	$ 4.28	35%	**$ 5.13**	$ 5.67	(10%)
Allocated to:						
Rancho Hermoso – tariff	**$ 4,767**	$ 374	1,175%	**$ 7,289**	$ 1,199	508%
Rancho Hermoso – NRI	**9,363**	3,190	194%	**14,566**	7,915	84%
	14,130	3,564	296%	**21,855**	9,114	140%
Other	**1,559**	1,197	30%	**2,296**	1,944	18%
Total operating expenses	**$ 15,689**	$ 4,761	230%	**$ 24,151**	$ 11,058	118%
$/bbl						
Rancho Hermoso – tariff	**$ 5.79**	**$** 4.28	35%	**$ 5.14**	**$** 5.91	(13%)
Rancho Hermoso – NRI	**$ 22.36**	**$** 17.22	30%	**$ 20.28**	**$** 20.32	-
Total operating expenses	**$ 12.47**	**$** 16.27	(23%)	**$ 11.13**	**$** 17.54	(37%)

Total operating expenses have increased 230% in Q2 2012 compared to Q2 2011, which relates to the significant increase in sales volumes between the comparable periods of 330%. Similarly, operating expenses increased 118% from H1 2012 compared to H1 2011, also due to an increase in sales volumes during the comparable period of 244%. As the sales volume increases relate entirely to increases in production from the Rancho Hermoso field, the Corporation has been able to realize operating efficiencies from H1 2011 to H1 2012. As a result, operating expenses per barrel have decreased 10% on a gross basis at Rancho Hermoso from H1 2011 to H1 2012. However, the Corporation did see increases in gross operating expenses per barrel of 35% from Q2 2011 to Q2 2012 due to increases in diesel prices and consumption, which remain a very significant operating cost of the field.

An analysis of transportation expenses is provided below:

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Rancho Hermoso – tariff	**$ 1,242**	$ 11	>1,000%	**$ 2,427**	$ 159	1,426%
Rancho Hermoso – NRI	**5,974**	1,369	336%	**9,508**	2,066	360%
Other	**668**	304	120%	**756**	496	52%
Total transportation expenses	**$ 7,884**	$ 1,684	368%	**$ 12,691**	$ 2,721	366%
$/bbl						
Rancho Hermoso – tariff	**$ 1.51**	$ 0.13	1,062%	**$ 1.71**	$ 0.78	119%
Rancho Hermoso – NRI	**$ 14.27**	$ 7.39	93%	**$ 13.24**	$ 5.30	150%
Total transportation expenses	**$ 6.26**	$ 5.75	9%	**$ 5.85**	$ 4.32	35%

Transportation expenses have increased in Q2 2012 compared to Q2 2011 and in H1 2012 compared to H1 2011 on a total and per barrel basis due to significantly increased sales volumes, higher trucking tariffs and increased average delivery distances.

Operating Netback

Total operating netback is heavily influenced by the sales volume split between tariff and NRI oil. Because tariff sales contributed a greater proportion to Q2 2012 and H1 2012 sales volumes compared to Q2 2011 (65% in Q2 2012 versus 30% in Q2 2011 and 65% in H1 2012 versus 32% in H1 2011) this has resulted in a reduction in total operating netback, even though tariff and NRI operating netbacks have each improved. Readers are cautioned that a comparison of total operating netback for the Corporation from one period to another is not meaningful if the ratio of tariff oil sales to NRI oil sales has materially changed, as is the case from Q2 2011 to Q2 2012 and from H1 2011 to H1 2012. A more meaningful analysis is to examine operating netback by major production category, which is provided after the table below.

	Three months ended December 31,			Six months ended December 31,		
$/bbl	**2011**	2010	Change	**2011**	2010	Change
Crude oil sales, net of royalties	**$ 43.89**	$ 57.68	(24%)	**$ 41.73**	$ 53.41	(22%)
Operating and transportation expenses	**(18.73)**	(22.02)	(15%)	**(16.98)**	(21.85)	(22%)
Operating netback (see note to reader above)	**$ 25.16**	$ 35.66	(29%)	**$ 24.75**	$ 31.56	(22%)

Operating netback by major production category was as follows:

	Three months ended December 31,			Six months ended December 31,		
$/bbl	**2011**	2010	Change	**2011**	2010	Change
Rancho Hermoso – tariff oil						
Tariff revenue	**$ 17.36**	$ 13.87	25%	**$ 16.35**	$ 13.76	19%
Operating and transportation expenses	**(7.30)**	(4.41)	66%	**(6.85)**	(6.70)	2%
Operating netback	**$ 10.06**	$ 9.46	6%	**$ 9.50**	$ 7.06	34%
Rancho Hermoso – NRI oil						
Crude oil sales, net of royalties	**$ 95.07**	$ 77.90	22%	**$ 90.63**	$ 73.26	24%
Operating and transportation expenses	**(36.63)**	(24.60)	49%	**(33.52)**	(25.62)	31%
Operating netback	**$ 58.44**	$ 53.30	10%	**$ 57.11**	$ 47.64	20%

General and Administrative Expenses

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Gross costs	**$ 6,466**	$ 5,260	23%	**$ 10,441**	$ 8,110	29%
Less: capitalized amounts	**(1,777)**	-	n/a	**(3,211)**	-	n/a
General and administrative expenses	**$ 4,689**	$ 5,260	(11%)	**$ 7,230**	$ 8,110	(11%)
$/bbl	**$ 3.73**	$ 17.97	(79%)	**$ 3.33**	$ 12.86	(74%)

Gross general and administrative expenses increased 23% in Q2 2012 compared to Q2 2011 primarily due to an increase in the number of staff to support operations in Colombia. Additionally, the Corporation accrues its annual bonuses in Q2 of each year. Total cash bonuses accrued in Q2 2012 were approximately $2.3 million.

Net Finance Income and Expense

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Interest income on bank deposits	**$ (669)**	$ (247)	171%	**$ (1,204)**	$ (498)	142%
Net commodity contract (gains) losses – realized	**-**	-	-	**78**	-	n/a
Net commodity contract (gains) losses – unrealized	**162**	1,511	(89%)	**(454)**	1,954	n/a
Net foreign exchange (gain) loss	**402**	(2,249)	n/a	**(4,642)**	(1,054)	340%
Accretion on equity tax payable	**6**	-	n/a	**32**	-	n/a
Accretion of decommissioning obligations	**273**	175	(56%)	**417**	1,077	(61%)
Interest expense	**1,137**	1,331	(15%)	**1,399**	2,705	(48%)
Net finance (income) expense	**$ 1,311**	$ 521	152%	**$ (4,374)**	$ 4,184	n/a

Interest – Interest income increased in Q2 2012 and H1 2012 compared to Q2 2011 and H1 2011 due to interest earned on higher cash balances. Interest expense decreased in Q2 2012 and H1 2012 compared to Q2 2011 and H1 2011 due to a combination of lower convertible debenture debt levels and capitalization of borrowing costs.

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

Commodity contracts – The Corporation enters into derivative risk management contracts in order to ensure a certain level of cash flows to fund planned capital projects. At December 31, 2011, the Corporation had one financial WTI oil collar outstanding under the following terms:

Period	**Volume**	**Type**	**Price Range**
Dec 2011 – June 2012	1,000 bbls/day	Financial WTI Oil Collar	$85.00 – $108.50

Stock-Based Compensation Expense

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Gross costs	**$ 2,696**	$ 1,809	49%	**$ 6,265**	$ 4,711	33%
Less: capitalized amounts	**(1,106)**	-	n/a	**(2,197)**	-	n/a
Stock-based compensation expense	**$ 1,590**	$ 1,809	(12%)	**$ 4,068**	$ 4,711	(14%)

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

Depletion, Depreciation and Amortization Expense

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Depletion, depreciation and amortization expense	**$ 14,516**	$ 3,082	371%	**$ 23,039**	$ 7,665	201%
$/bbl	**$ 11.53**	$ 10.53	10%	**$ 10.62**	$ 12.16	(13%)

Total depletion, depreciation and amortization costs have increased in Q2 and H1 2012 as compared to Q2 and H1 2011 as a result of significantly increased production levels. Per barrel costs have generally decreased from H1 2011 to H1 2012 primarily as a result of positive reserve revisions at June 30, 2011 which affected the calculation for H1 2012. This is offset in Q2 2012 by the significant development costs spent at Rancho Hermoso in the quarter. Under IFRS, the Corporation depletes its assets on a component basis utilizing total proved plus probable reserves as opposed to depleting it assets using total proved reserves under Canadian GAAP.

Gain / Loss on Overlifted Volumes Payable

Under its contracts with Ecopetrol, the Corporation would normally deliver Ecopetrol's share of crude oil production volumes in kind at a designated delivery point. However, due to capacity restrictions at this delivery point, Ecopetrol typically takes delivery of its production volumes at the Rancho Hermoso field. Ecopetrol has not always been able to take delivery of its production volumes in kind and the Corporation has often been required to sell such volumes since sufficient on-site storage facilities were not available. When the Corporation sold these "overlifted" volumes, a liability was recorded for the amount of the sale and prepaid transportation was recorded for associated transportation costs. As overlifted volumes were to be delivered to Ecopetrol in future periods, the liability and prepaid transportation amounts were reduced with corresponding recognition of such amounts as revenue and transportation costs. Since the participation contract with Ecopetrol required delivery of production volumes in kind, the Corporation revalued the liability at each period-end to reflect the fair value of the crude oil owing to Ecopetrol at that time and gains or losses related to such were recognized in profit or loss in the period. In December 2011, the Corporation signed an agreement with Ecopetrol and repaid its outstanding overlifted volumes in cash for approximately $24.8 million, which reflected the actual sales value the Corporation received for the crude oil less actual transportation costs. Related to this settlement, the Corporation also commenced additional discussions with Ecopetrol regarding transportation tariffs on previous shipments of crude oil. Consequently, the Corporation has not recognized the finalization of the settlement of the overlifted volumes payable pending the outcome of those discussions.

Income Tax Expense

	Three months ended December 31,		Six months ended December 31,	
	2011	2010	**2011**	2010
Current income tax expense	**$ 435**	$ 3,273	**$ 4,350**	$ 3,105
Deferred income tax expense (recovery)	**9,272**	(1,743)	**12,032**	(2,268)
Income taxes	**$ 9,707**	$ 1,530	**$ 16,382**	$ 837

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 33%. During Q2 2012, the Corporation settled its overlifted volumes payable which resulted in the reversal of the deferred tax asset related thereto and a deduction for current income tax. Since the settlement amount was less than the recorded amount in the interim financial statements, the reversal resulted in an additional deferred income tax expense for which no current income tax deduction was received.

Cash and Funds from Operations and Net Income (Loss)

	Three months ended December 31,			Six months ended December 31,		
	2011	2010	Change	**2011**	2010	Change
Cash provided by operating activities	**$ 35,758**	$ 15,394	132%	**$ 65,894**	$ 17,885	268%
Funds from operations	**24,480**	2,579	849%	**42,241**	10,345	308%
Per share – basic and diluted ($)	**0.05**	0.01	400%	**0.08**	0.02	300%
Net income (loss)	**(2,423)**	(14,918)	(84%)	**11,063**	(44,986)	n/a
Per share – basic and diluted ($)	**-**	(0.03)	(100%)	**0.02**	(0.10)	n/a

Funds from operations increased in Q2 2012 and H1 2012 compared to Q2 2011 and H1 2011 primarily due to significantly increased sales volumes and higher operating netbacks.

Capital Expenditures

	Three months ended December 31,		Six months ended December 31,	
	2011	2010	**2011**	2010
Drilling and completions	**$ 25,068**	$ 11,841	**$ 40,263**	$ 19,675
Facilities and infrastructure	**21,729**	3,749	**30,833**	4,101
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other	**15,628**	6,813	**22,685**	6,868
Total capital expenditures	**$ 62,425**	$ 22,403	**$ 93,781**	$ 30,644
Recorded as:				
Expenditures on exploration and evaluation assets	**$ 10,941**	$ -	**$ 17,664**	$ -
Expenditures on property, plant and equipment	**$ 51,484**	$ 22,403	**$ 76,117**	$ 30,644

Capital expenditures in Q2 2012 primarily relate to:

- RH 12 and RH 13 drilling and completion costs at the Rancho Hermoso field;
- RH 14 drilling costs at the Rancho Hermoso field;
- Cachalote drilling costs on the Andaquies block;
- Tamarin-1 drilling costs on the Tamarin block;
- Seismic costs related to the acquisition of 250 kilometres of 2D seismic at Tamarin; and
- Cost related to the construction of the gas plant facilities and facilities expansion at the Rancho Hermoso field.

In addition, other capital expenditures in H1 2012 primarily relate to:

- RH 11 drilling and completion costs at the Rancho Hermoso field;
- Tamarin-1 drilling costs on the Tamarin block;
- Seismic costs relate to the acquisition of 250 kilometres of 2D seismic at Cedrela and 300 square kilometres of 2D seismic at Sangretoro.

LIQUIDITY AND CAPITAL RESOURCES

Capital Funding

Based on the Corporation's financial position and liquidity at December 31, 2011, its projected future cash flows, and its available credit capacity, management expects to be able to fund its working capital and capital project needs, and meet its other obligations, including servicing interest on its convertible debentures and bank debt through the end of calendar 2012. At December 31, 2011, the Corporation had cash, cash equivalents, and restricted cash of $90.7 million and working capital of $68.0 million. The Corporation believes it is well positioned financially with significant available credit capacity, assets that are providing strong production growth and operating netbacks, along with an extensive inventory of exploration prospects. The Corporation's assets provide significant funds from operations and are its largest source of liquidity. The Corporation has a history of generating positive funds from operations.

Credit Facilities and Debt

The Corporation, through its wholly-owned subsidiary, Canacol Energy Colombia S.A. (the "Borrower"), entered into a credit agreement for up to $27 million to fund the construction of a gas liquids separation facility at its Rancho Hermoso field. As at December 31, 2011, $13.1 million was drawn on the credit facility to fund such construction costs under a predetermined schedule. The credit facility is repayable in ten equal principal payments plus interest due at the end of each three month period starting on September 1, 2012. The facility bears interest at LIBOR plus 2.50% and is unsecured. The Corporation is currently in negotiations with its bank to increase the facility to $32 million.

The Borrower is subject to certain financial and operations covenants, including maintaining a Leverage Ratio of less than 2.25, an Interest Coverage Ratio of less than 1.25, both calculated with reference to the Borrower's trailing twelve-month EBITDA, and minimum non-tariff oil production, net after royalties, of 3,000 barrels of oil per day ("bopd") from the closing date to September 30, 2012, and 2,500 bopd thereafter.

At December 31, 2011, the Corporation had revolving lines of credit in place in Colombia with an aggregate borrowing base of $19.6 million (COP$ 38.1 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. At December 31, 2011, no amounts were drawn under the facilities.

At December 31, 2011, the Corporation had letters of credit outstanding totalling $10.2 million to guarantee work commitments on exploration blocks. The total of these letters of credit reduce the amounts available under the revolving lines of credit described above.

The Corporation has convertible debentures outstanding with a face value of $25.1 million (fair value – $25.1 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.

Share Capital

At February 8, 2012, the Corporation had 618,302,426 common shares, 3,286,920 warrants, 47,922,027 stock options, and 190,000 restricted share units 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, 2011:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt	2,620	10,480	-	13,100
Trade and other payables	47,133	-	-	47,133
Commodity contracts	122	-	-	122
Equity tax payable	1,135	2,270	-	3,405
Convertible debentures – principal	-	-	25,092	25,092
Convertible debentures – interest	2,007	4,014	1,003	7,024
Warrants	1,548	-	-	1,548
Exploration contracts (see below)	63,900	13,000	-	76,900
Office leases	865	1,569	1,968	4,402
	119,330	31,333	28,063	178,726

Exploration Contracts

The Corporation has entered into a number of exploration and production contracts in Colombia, Brazil and Guyana which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding commitments at December 31, 2011 of $91.6 million and has issued $17.1 million in financial guarantees, $10.2 million of which are secured under the Corporation's credit facilities through letters of credit and the remainder is held in trust and recorded as restricted cash.

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

Colombia

The Corporation has net work program and farm-in commitments totalling approximately $91.6 million, of which $84.8 million are due within a year. These commitments are planned to be satisfied by means of seismic work and exploration drilling.

Basin	Commitment Date	Block	Net Acreage	Working Interest	Phase	Work Program Commitments
			(000 acres)			
Upper Magdalena	February 17, 2014	COR-11	124	70% (1)	1	155 km of 2D seismic and 1 exploration well
Upper Magdalena	February 17, 2014	COR-39	67	70% (1)	1	90 km of 2D seismic and 2 exploration wells
Middle Magdalena	June 29, 2012	Santa Isabel	91	90% (2)	1&2	60 sq. km of 3D seismic and 1 exploration well
Middle Magdalena	February 19, 2012	VMM-2	30	40%	1	86 sq. km of 3D seismic and 1 exploration well
Middle Magdalena	June 30, 2012	VMM-3	16	20% (4)	1	75 km 2D seismic, 28 sq. km 3D seismic and 1 exploration well
Putumayo	February 6, 2014	Andaquies	41	36%	1	1 exploration well
Putumayo	February 28, 2010 (block under suspension)	Coati	25	40%	5	1 exploration well
Putumayo – Caguan	August1, 2012	Sangretoro	385	100%	1	300 km of 2D seismic
Putumayo – Caguan	June 29, 2012	Cedrela	320	100%	1	250 km of 2D seismic
Putumayo – Caguan	July 29, 2012	Portofino	103	40%	1&2	1 exploration well
Llanos Basis	September 13, 2009	LLA 23	82	71% (3)	1&2	94 sq. km 3D seismic and 1 exploration well
Llanos Basis	September 14, 2012	LLA 10	74	39%	1	160 km 2D seismic, 28 sq. km 3D seismic and 1 exploration well
Llanos Basis	June 29, 2012	Cano los Totumos	11	51%	1	50 sq. km of 3D seismic and 1 exploration well

(1) The Corporation completed a farm-out of the COR-11 and COR-39 blocks in September 2011 whereby the farmee has agreed to pay 60% of the phase 1 work program commitments on each block.
(2) Working interest increased to 100% subsequent to December 31, 2011.
(3) Working interest increased to 80% subsequent to December 31, 2011.
(4) Full carry on minimum work program commitment by partner.

Brazil

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

Guyana

The Corporation has net work program commitments totalling approximately $5.0 million due within a year. The operator is currently in discussions with the Guyanese government who have agreed to extend Takutu PPL to the initial exploration phase ending May 2015. The operator has stated that it has no reason to believe that the extension will not receive final approval.

Gas Purchases and Gas Plant

On August 31, 2011, the Corporation was awarded a contract by Ecopetrol to purchase produced natural gas from the Rancho Hermoso field at a fixed price of $6.50/MMbtu, which includes the associated liquids – natural gasoline, propane and butane. The contract is effective on January 1, 2012 and is for a period of 5 years. The Corporation has initiated the construction of a gas liquids separation facility with the intention of processing the future natural gas production and selling the resulting liquids. The gas plant construction is underway and is expected to cost approximately $30.8 million in total with all ancillary projects. At December 31, 2011, the Corporation had spent $13.7 million towards the construction of the gas plant; the remaining amount is expected due within a year. The Corporation has funded the construction of the gas plant through its $27 million term loan, which it is currently negotiating to have increased up to $32 million.

Trucking Contract

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

SUBSEQUENT EVENTS

On January 30, 2011, the Corporation issued an additional 4,806,445 common shares to acquire the remaining Carrao shares pursuant to the compulsory acquisition provisions of the *Business Corporations Act* (British Columbia) (note 5).

On January 10, 2012 the Corporation, through a subsidiary, entered into an arm's length agreement for the acquisition of an additional 9% interest in the LLA 23 block and an additional 10% interest in the Santa Isabel block, both in Colombia. The consideration of approximately $4.5 million is subject to adjustments and payable in cash or in common shares of the Corporation, at the Corporation's election. The agreement also provides for the Corporation, through a subsidiary, to lend the vendor on a secured basis up to $4.5 million for a 90 day period. In February 2012, the transaction was partially completed with the loan advance and the execution of the transfer documents for the two blocks.

In February 2012, a company in which the Corporation has a non-operated 25% equity 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 committed to spend a total of $334 million ($92.9 million, net to the Corporation) for the drilling of 31 new development wells and the workover of 28 existing wells over the 15 year period of the contract. The Corporation's net share of such work program commitments during calendar 2012 is $10.2 million. In return for increased production at EPPE's mature fields, the operator will receive a fixed price tariff of $39.56 for each incremental barrel of oil produced, which is insensitive to oil price fluctuations. All operating expenses are paid for by EPPE.

OUTLOOK

For calendar 2012, the Corporation's focus is threefold: 1) to achieve strong base production and cash flow growth from drilling and re-completion programs at its Rancho Hermoso field; 2) to access potential near-term light oil production and cash flow from the LLA 23 contract, which is located immediately north of and on trend with the Rancho Hermoso field; and 3) to execute on a large exploration program which targets heavy oil in the Putumayo-Caguan basin and light oil in the Putumayo and Middle Magdalena basins. Of the Corporation's 2012 exploration budget of $88 million, approximately 60% is targeted for light oil exploration programs and approximately 40% is targeted for heavy oil programs. In December 2011, the Corporation set an overall $150 million capital program for calendar 2012 and average production guidance of 14,000 to 16,000 bopd for the same period. In February 2011, the Corporation announced its participation in an incremental production contract on the Libertador and Atacapi fields in Ecuador. As a result, the Corporation expects to incur approximately $10.2 million of additional capital expenditures with respect to this contract in calendar 2012.

SUMMARY OF QUARTERLY RESULTS

	IFRS						Canadian GAAP	
	2012		2011				2010	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial								
Crude oil sales	**40,941**	26,453	37,339	23,452	15,669	15,219	5,330	4,992
Tariff revenue	**14,300**	8,877	9,676	8,677	1,212	1,579	1,874	1,607
Total revenues	**55,241**	35,330	47,015	32,129	16,881	16,798	7,204	6,599
Funds from operations [1]	**24,480**	17,761	11,200	18,024	1,829	7,766	(1,443)	(1,161)
Per share – basic and diluted ($)	**0.05**	0.03	0.02	0.04	-	0.02	-	-
Net income (loss)	**(2,423)**	13,486	19,625	(2,069)	(14,918)	(30,068)	(11,048)	(5,130)
Per share – basic and diluted ($)	**-**	0.03	0.04	-	(0.03)	(0.07)	(0.02)	(0.01)
Capital expenditures	**62,425**	31,356	24,824	20,665	22,403	8,241	6,089	4,122
Operations								
Tariff oil production (bopd)	**8,971**	6,476	7,568	6,870	980	1,259	1,152	1,549
NRI oil production (bopd)	**4,422**	3,274	3,880	3,001	2,650	1,729	1,559	858
Total oil production (bopd)	**13,681**	9,750	11,448	9,871	3,630	2,988	2,711	2,407

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

RISKS AND UNCERTAINTIES

There have been no significant changes in the three months ended December 31, 2011 to the risks and uncertainties as identified in the MD&A for the year ended June 30, 2011.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

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

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

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

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

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

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

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

Contingencies **–** In the normal course of operations, the Corporation has disputes with industry participants for which the Corporation currently cannot determine the ultimate result. The Corporation records costs as they are incurred or become determinable.

CHANGES IN ACCOUNTING POLICIES

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

REGULATORY POLICIES

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.

Internal Controls over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate Internal Control over Financial Reporting ("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, 2011, 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 three months ended December 31, 2011, there has been no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Limitation on Scope of Design

In accordance 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 Carrao Energy Ltd., a privately held entity which was acquired by the Corporation effective November 29, 2011, 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 Carrao in a manner consistent with the Corporation's other operations. The Corporation's management is currently in the process of integrating Carrao into the existing internal controls and procedures of Canacol.

Carrao constitutes 14.2% of net assets, 10.6% of total assets, nil% of net revenues, and nil% of income before income taxes of the consolidated financial statements amounts as at and for the three months ended December 31, 2011.

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.