

Canacol Energy Ltd.

A large, semi-transparent blue globe is centered on the page. The globe shows the continents of North and South America in a light blue/white color. Overlaid on the globe is the text "Management Discussion and Analysis" and "Year ended June 30, 2011".

Management Discussion and Analysis

Year ended June 30, 2011

September 26, 2011

CAUTIONARY NOTE

This Management's Discussion and Analysis ("MD&A") for Canacol Energy Ltd. ("Canacol" or the "Corporation") of the financial results and related data is reported in United States dollars, has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), and should be read in conjunction with the audited consolidated financial statements for the fiscal year ended June 30, 2011 and the respective notes thereto. Additional information relating to the Corporation is on SEDAR at www.sedar.com.

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 ability to access sufficient capital from internal and external sources. In particular to forward-looking comments in this MD&A readers are cautioned that there can be no assurance that: the Corporation will be able to attain sufficient capital and financing to fund its expected obligations; that the Corporation will be able to increase production in Brazil, Colombia, or Guyana and achieve expected variable cost efficiencies and an overall reduction of costs on a per barrel basis; that hydrocarbon based royalties assessed by the Brazilian and Colombian governments will remain consistent or that the Brazilian and Colombian 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, the MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook"). These statements are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in oil and gas prices; the results of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; and risks associated with oil and gas operations, many of which are beyond the control of the Corporation. Accordingly, there is no representation by Canacol 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, Canacol 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 Canacol 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.

Canacol is a public company listed on the Toronto Stock Exchange (“TSX”) and trades under the symbol CNE. The Corporation also trades on the Bolsa de Valores de Colombia (“BVC”) under the symbol CNE.C.

Unless otherwise stated, all dollar amounts presented in this MD&A are in thousands of United States dollars. All references to C\$ are to Canadian dollars, references to US\$ or \$ are United States (U.S.) dollars, references to BRL\$ are to Brazilian Real, and references to COP\$ are to Colombian Pesos.

YEAR ENDED JUNE 30, 2011 IN REVIEW

HIGHLIGHTS FROM Q1-F2011

- On July 16, 2010, the Corporation closed an 8% convertible debenture financing, on a “bought deal” basis, with a syndicate of underwriters (“the Underwriters”) led by Canaccord Genuity Corp., and including FirstEnergy Capital Corp., Cormark Securities Inc., Citigroup Global Market Canada Inc. and Mackie Research Capital Corp. The Underwriters purchased \$39,385 (C\$41,500) principal amount of Canadian dollar denominated convertible unsecured debentures with an interest rate of 8% per annum, payable semi-annually on the last day of June and December commencing on December 31, 2010. The debentures are convertible at the holder’s option into common shares of the Corporation at any time prior to the earlier of the maturity date or the business day immediately preceding the date fixed by the Corporation for redemption at a conversion price of \$0.9989 (C\$1.0526) per common share, being the ratio of 950 common shares per \$949 (C\$1,000) principal amount of debentures. The debentures, including the underlying common shares issuable upon conversion, redemption or maturity of the debentures are traded on the TSX under the trading symbol “CNE.DB”.
- On July 16, 2010, the Corporation issued 4,421,260 common shares of the Corporation in connection with the purchase of a royalty interest from Gemini Oil and Gas Fund II, LP (“Gemini”) in addition to a cash payment of \$18,000 to Gemini.
- On July 22, 2010, the Corporation commenced trading on the BVC under the trading symbol “CNE.C”.
- On August 27, 2010, the Corporation completed flow testing of the three zones in the Rancho Hermoso 6 (“RH 6”) well and achieved a total gross flow rate of 12,847 barrels of oil per day (“bbl/d”). The RH 6 well encountered 115 feet (“ft”) of net oil pay within 5 different reservoir intervals, which include, from top to bottom, the C7, Mirador, Los Cuervos - Barco, Guadalupe, and Ubaque.
- On September 7, 2010, the Corporation completed the drilling and testing of the first horizontal well, Capella FH-10 which tested at a gross rate up to 437 bbl/d, and the Romero A1 well. The Corporation also completed the acquisition and processing of 184 square kilometres of 3D seismic over the discovery, and commenced the drilling of the Capella L-11 well.

HIGHLIGHTS FROM Q2-F2011

- On October 26, 2010 the Corporation completed drilling and testing of the Rancho Hermoso 7 well (“RH 7”), which tested at a flow rate of 5,019 bbl/d from the Los Cuervos reservoir. The Los Cuervos - Barco reservoir at RH 7ST contains 34 ft of net oil pay. The Los Cuervos - Barco was perforated between 9,206 and 9,217 ft md and flowed at a final gross rate of 5,019 bbl/d (1,255 bbl/d net) of 34° API light gravity oil with 4% water cut using an electrical submersible pump set to a frequency of 35 Hz during a 24 hour flow period. The RH 7ST well is currently producing from the Guadalupe reservoir.

- The rig was mobilized to the Rancho Hermoso 8 (“RH 8”) well which was spud in the first week of November. The RH 8 well targeted the Los Cuervos - Barco and Guadalupe reservoirs at a location approximately 1,500 ft to the southwest of the Rancho Hermoso 5 (“RH 5”) well.
- On November 9, 2010, the Corporation engaged with Citivalores S.A. Sociedad Comisionista de Bolsa in Colombia to lead a non-deal road show to Santiago, Chile and Lima, Peru from November 16th through 18th in preparation of the integration of the stock exchanges in these three countries. The integration of these three markets offered the potential to significantly broaden Canacol’s institutional and retail shareholder base in South America as initially Canacol was one of only three energy stocks available for investment in the integrated market.
- On December 20, 2010, the Corporation completed drilling and testing of Rancho Hermoso 9 well (“RH 9”). The RH 9 well encountered 109 ft of net oil pay within 5 different reservoir intervals, which include, from top to bottom, the C7, Mirador, Los Cuervos-Barco, Guadalupe, and Ubaque. The Corporation drilled the RH 9 well before the RH 8 well for scheduling purposes.
- The Corporation spud the Apoteri K-2 (“K2”), the first exploration well on the Takutu Block in Guyana, on December 31, 2010. The K-2 well was drilled to a measured depth of approximately 11,000 feet and targeted the same productive reservoirs that tested over 400 barrels of oil per day of 42° API light oil from the Karanambo 1 well drilled in 1982 and located 600 metres away.

HIGHLIGHTS FROM Q3-F2011

- On January 17, 2011, the Corporation completed production testing of the Los Cuervos - Barco reservoir in Rancho Hermoso 8 well (“RH8”). The RH8 well encountered 93 feet ft of net pay within 4 different reservoir intervals, which included, from top to bottom, the Mirador, Los Cuervos-Barco, Guadalupe, and Ubaque. The Los Cuervos - Barco reservoir at RH 8 contains 15ft of net oil pay, and was perforated between 9,349 and 9,364 ft md. The well flowed at a final stable gross rate of 3,927 bbl/d (982 bbl/d net) of 35° API light gravity oil with 1.5% water cut using an electrical submersible pump (“ESP”) set to a frequency of 75Hz during a 24 hour flow period.
- On January 4, 2011, the Corporation spud the Rancho Hermoso 10 well (“RH 10”) and reached a total depth of 10,305 ft md on January 16, 2011 in the Ubaque reservoir in a record 12 days. The RH 10 well encountered 110 feet of oil pay in the C7, Mirador, Los Cuervos-Barco, Guadalupe and Ubaque reservoirs, and tested a final stable gross rate of 8,122 bbl/d (2,030 bbl/d net) in the Ubaque reservoir and 10,944 bbl/d (2,736 bbl/d net) in the Guadalupe reservoir. The Los Cuervos - Barco reservoir at RH 10 contains 19ft of net oil pay, and was perforated between 9,410 and 9,425 ft md. The Los Cuervos-Barco flowed at a final stable gross rate of 6,792 bbl/d (1,698 bbl/d net) of 34° API oil. The C7 reservoir at RH 10 contains 12 ft of net oil pay, and was perforated between 8,974 ft md. An electrical submersible pump (“ESP”) was installed and the C7 reservoir flowed at a gross rate of approximately 429 bbl/d of 34° API oil.
- On February 15, 2011, the Corporation closed a bought deal common share financing for gross proceeds of \$58,267 (C\$57,608) and net proceeds of \$55,259 (C\$54,656) through the issuance of 41,745,000 common shares at a price of C\$1.38 per share.
- In March 2011, the Corporation received formal approval from Agencia Nacional de Hidrocaburos (“ANH”) on three new Exploration and Production contracts (Sangretoro, COR 11 and COR 39).

- The Corporation funded a 0.5% participation in the new pipeline construction project, the Oleoducto Bicentenario de Colombia (the “OBC”) at a cost of approximately \$5,000. To date the Corporation has invested \$2,589.

HIGHLIGHTS FROM Q4-F2011

- On May 3, 2011, the Corporation completed its listing on the Toronto Stock Exchange. Canacol shares continue to be listed under the symbol “CNE”. Debentures continue to be listed under the symbol “CNE.DB”.
- On April 25, 2011, the Corporation provided an update on the Apoteri K-2 exploration well in Guyana. The well reached target depth at 9,812 feet measured depth within the Apoteri Formation on April 20, 2011. Light oil and gas shows were encountered within the Apoteri Formation, but due to poor reservoir quality, no reservoir fluids were recovered during drill stem testing. The K-2 well was subsequently abandoned.
- On May 30, 2011, the Corporation entered into farmin and joint operating agreements with C&C Energia Ltd (“C&C”) in the Andaquies and Coati Exploration and Production (“E&P”) contracts located in the Putumayo basin in Colombia. Upon the Corporation meeting its obligation to pay 72% of the cost associated with acquiring seismic and drilling one exploration well it will earn 36% of C&C’s 90% working interest in the Andaquies E&P contract. Upon the Corporation meeting its obligation to pay 80% of the cost associated with acquiring seismic and drilling one exploration well it will earn 40% of C&C’s 100% working interest in the Coati contract.
- On June 22, 2011, the Corporation announced that it was commencing its heavy oil exploration program targeting structured in the Tamarin and Cedrela blocks.
- On June 29, 2011, the Corporation disclosed a new pool at its Rancho Hermoso field. The C7 reservoir was completed and tested over a 1 week period in the Rancho Hermoso 4 well, flowing at an average gross rate of 1,786 bbl/d (447 bbl/d net) of 34° API light oil.

SUBSEQUENT EVENTS

- Canacol has signed joint venture agreement with a Colombian Truck company (“Trucker”), for the exclusive use of 100 trucks for transportation of crude oil from Canacol’s operations in Colombia for a period of 3 years. Canacol will pay transportation fees plus an additional 7.5% of administrative costs. Any excess of the fees charged over the actual operating costs will be shared equally between the partners at the end of each year. Canacol has made a refundable advance of approximately \$499 to initiate fabrication of the trucks and has an option to purchase up to 50 trucks at the end of the 3 year agreement.
- On July 13, 2011, the Corporation received the final approval from ANP to acquire the operator’s interest and operatorship in the block REC-T-170 in Brazil and the transaction has closed.
- On August 31, 2011, the Corporation was awarded a contract by Ecopetrol to purchase produced gas from the Rancho Hermoso field for \$6.50 per thousand BTUs (\$15.48 per msfpd). The 5 year contract will be effective on January 1, 2012 and a renewal term if economically attractive would be negotiated at the end of the contract.

- On September 15, 2011, the Corporation farmed out a 30% working interest of its 100% operating working interest on the COR 11 and COR 39 Exploration and Production contract (“E&P Contracts”) located in the Upper Magdalena Basin of Colombia to Sintana Energy Ltd. in exchange for Sintana funding 60% of the Phase 1 exploration program on each block. The Phase 1 work commitments for the COR 11 E&P contract include the acquisition of 155 kilometers (“km”) of 2D seismic and the drilling of one exploration well. The Phase 1 commitments for the COR 39 E&P Contract include the acquisition of 120 km of 2D seismic and the drilling of 2 exploration wells. The Phase 1 period for each of the contracts is 3 years in length, expiring in February 2014. Canacol shall remain the operator of both of the E&P contracts.
- Subsequent to June 30, 2011, 405,000 shares were issued on exercise of options, 69,999 shares were issued on employees as a signing bonus, 8,519 shares were issued for payment of interest and 833,331 common shares were issued on conversion of 12% debentures.
- Subsequent to June 30, 2011, the Corporation granted 8,162,500 stock options. A total of 4,935,000 of these stock options were granted to directors and officers of the Corporation. The options were granted at exercise prices ranging from C\$0.90 to C\$0.93 per common share and expire five years after the date of grant.

COMPANY OVERVIEW AND BACKGROUND

Canacol Energy Ltd. (“Canacol” or the “Corporation”) (TSX: CNE) and (Bolsa de Valores de Colombia: CNE.C) is a Canadian-based independent oil exploration company operating in Colombia, Guyana and Brazil. The Corporation’s average worldwide net production for the three months ended June 30, 2011 was approximately 11,523 barrels of oil per day (“bbl/d”), which consisted of 3,871 bbl/d net royalty production and 7,652 bbl/d of tariff production.

The Corporation’s current production guidance for calendar 2011 is a target of 10,500 to 11,500 bbl/d.

Colombia

Canacol has interests in 8 exploration and production contracts in Colombia. In calendar 2011 the Corporation plans to drill 6 development wells at its operated Rancho Hermoso Field (2 wells already drilled during the first calendar quarter 2011 (“RH 8” and “RH 10”), 28 appraisal and development wells at its heavy oil discovery at Capella, 5 exploration wells on its Tamarin, Cedrela and Sangretoro E&P heavy oil contracts adjacent to the Capella oil discovery, and 3 exploration wells on the Coati and Andaquies E&P contracts operated by C&C Energia. Calendar 2011 activity in Colombia also includes the acquisition of 650 km of 2D seismic on its Tamarin, Cedrela, and Sangretoro E&P contracts in the Caguan - Putumayo Basin (Tamarin and Cedrela programs completed in the first half of calendar 2011, program on the Sangretoro contract 50% completed at the end of calendar third quarter 2011), the acquisition of 115 km of 2D seismic on COR 39 during the calendar year 2011, the expansion of facilities at the Rancho Hermoso Field (completed at the end of second quarter calendar 2011), and the funding of the Corporation’s 0.5% working interest in the OBC pipeline project.

Llanos Basin

The Corporation has operated interests in the Rancho Hermoso (100% working interest) and Entrerrios (60% working interest) producing fields in the Llanos Basin. Both contracts are operated under Production Sharing and Risked Service contracts with Ecopetrol, the state oil company of Colombia.

Rancho Hermoso Production Contract (100% operated working interest) and Entrerrios Production Contract (60% operated working interest)

The Corporation's current average share of production from the Rancho Hermoso and Entrerrios fields for the three months ended June 30, 2011 is approximately 11,319 *bbl/d*, comprised of 3,667 *bbl/d* net of government royalty, and 7,652 *bbl/d* of tariff production. A portion of the Corporation's net oil production currently is secured by commodity contracts (Refer to the Risk Section).

For the tariff oil production, the Corporation receives an operating tariff per gross produced barrel of oil from Ecopetrol. The average tariff price for calendar 2011 and 2012 is expected to be approximately \$15.04 and \$17.36, respectively, per gross barrel plus transportation reimbursement, and is insensitive to West Texas Intermediate oil price fluctuations.

The Corporation plans to drill 6 development wells at Rancho Hermoso during the calendar year 2011. The RH 8 and RH 10 wells were completed in January and February of 2011, and the Corporation plans to drill the remaining 4 wells in the last half of calendar 2011. In addition to the new development wells, the Corporation has expanded the fluid handling capacity of existing facilities in order to process additional production. The facility expansion was completed in June and has the capacity to handle 200,000 barrels of fluid per day.

Putumayo - Caguan Basin

The Corporation is one of the largest exploration landholders in the Putumayo - Caguan Basin of southern Colombia, with working interests in four exploration and production contracts, all of them awarded under the new terms as regulated by the Agencia Nacional de Hidrocarburos ("ANH").

Ombu E&P Contract - Capella Oil Discovery Appraisal

The Corporation, under a farm out agreement entered into in July 2008, earned a 10% working interest in the Capella conventional heavy oil discovery operated by Sinochem Corporation on the Ombu E&P contract, where the operator is continuing with its appraisal drilling. The current average share of production from Capella field is approximately 106 *bbl/d* net of government royalty.

Since its discovery in 2008 the Corporation has participated in the drilling of 15 wells, and the acquisition of 189 square kilometres of 3D seismic. During calendar 2011, the Corporation intends to spend \$17,000 net to fund its share of the drilling and completion of 28 new wells and the construction of production facilities, as the development of the field commences.

Tamarin E&P contract (100% operated working interest)

In August 2009, Canacol, through its subsidiary Canacol Energy Colombia S.A. (formerly "Rancho Hermoso S.A."), was awarded the Tamarin Exploration and Production Contract ("Tamarin E&P contract") by the ANH.

The Corporation has a 100% working interest in the block, which is approximately 67,922 acres in size and is located approximately 25 km to the southwest of the Ombu contract. Based upon the available geophysical and geological data in this frontier area, the Corporation has determined that the fault trend present at its Capella discovery to the northeast continues onto the Tamarin contract, setting up the potential for another Capella type heavy oil prospect. Canacol now has a significant operated exploration position at 100% working interest immediately offsetting its Capella heavy oil discovery. Canacol acquired 60 km of 2D exploration seismic on the Tamarin contract in May 2010 in satisfaction of the Phase 1 work program commitments. The Corporation plans to drill 1 exploration well on Tamarin commencing early in the fourth calendar quarter of 2011.

Cedrela Exploration and Production Contract (100% operated working interest)

In May 2010, Canacol was awarded the Cedrela Exploration and Production Contract ("Cedrela") by the ANH. Cedrela is located immediately south of the Tamarin E&P Contract.

The Corporation has a 100% working interest in the block, which is approximately 319,804 acres in size and is located in the Caguan - Putumayo Basin of Colombia. Based upon the available geophysical and geological data in this frontier area, the Corporation has identified 2 large structures similar in character to Capella on the Cedrela block. The Corporation has completed the acquisition of 250 kilometres of 2D seismic on the block and finished the processing and interpreting of this seismic data in September 2011. The Corporation plans to drill the 2 exploration wells in the Cedrela block in the fourth calendar quarter of 2011.

Sangretoro E&P Contract (100% operated working interest)

In February 2011, the Corporation was awarded the Sangretoro Exploration and Production contract ("Sangretoro E&P Contract"). The Corporation has a 100% working interest in the block, which is approximately 385,344 acres in size and is located in the Putumayo-Caguan Basin of southern Colombia, and includes some of the lands previously under the Pacarana TEA.

The Corporation is currently acquiring 300 km of 2D exploration seismic on the contract and expects to complete the seismic program in early fourth calendar quarter 2011. The Corporation plans to use the new seismic data to drill 2 exploration wells in the first half of calendar 2012.

Coati and Andaquies (36% and 40% non-operated working interest)

On May 30, 2011, the Corporation entered into definitive Farm-in and Joint Operating Agreements with C&C Energia Ltd. for the farm-in to the Andaquies and Coati Exploration and Production ("E&P") contracts located in the Putumayo basin in Colombia. The Coati and Andaquies E&P contracts are royalty contracts governed under the terms of the Agencia Nacional de Hidrocarburos. C&C Energia Ltd. will continue to function as the Operator of both blocks.

Upon the Corporation meeting its obligation to pay 72% of the cost associated with acquiring seismic and drilling one exploration well it will earn 36% of the Operators 90% working interest in the Andaquies E&P contract. Upon the Corporation meeting its obligation to pay 80% of the cost associated with acquiring seismic and drilling one exploration well it will earn 40% of the Operators 100% working interest in the Coati contract.

The Operator plans to drill three exploration wells targeting light oil prospects in the fourth calendar quarter of 2011, two on the Andaquies contract and one on the Coati contract, pending the receipt of all necessary permits and approvals.

Upper Magdalena Valley Basin

COR 11 and 39 E&P Contracts (100% operated working interest)

In February, 2011, the Corporation was awarded the COR 11 and COR 39 Exploration and Production contracts (COR 11 and COR 39 E&P Contracts). The Corporation has a 100% working interest in the blocks, which are approximately 176,915 and 95,106 acres in area, respectively, and are located in a new core area in the Upper Magdalena Valley in close proximity to the Guando and Abanico producing oil fields.

The Corporation has mapped 7 prospects and leads on the two contracts, and is committed to spending approximately \$28,000 during the first phase of the exploration work program, which has a duration of 3 years from the date of formal award. The work program involves the acquisition of 245 km of 2D exploration seismic and the drilling of 3 exploration wells. On September 15, 2011 the Corporation announced that it had farmed out a 30% working interest in each contract to Sintana Energy Ltd. In exchange for Sintana funding 60% of the Phase 1 exploration program on each block, at an estimated cost of \$28,000.

Guyana E&P

Takutu PPL (65% non-operated working interest)

In May 2008, the Corporation negotiated a farm-in to a 7,800 sq km exploration contract located in the Takutu Basin, onshore Guyana adjacent to the border with Brazil, awarded to Groundstar Resources Ltd. (“Groundstar”) in July 2005 for a four year period. The operator was successful in extending the term of the contract to July 2011 with a commitment to drill 2 wells. Canacol has a 90% working interest in the contract, with Groundstar Resources Limited (“Groundstar”), the operator of the Petroleum Prospecting License (“PPL”), holding the remaining 10%. Sagres Energy Inc. has earned a 25% working interest in the PPL from Canacol by paying for 30% of the cost to drill the K-2 exploration well.

The Corporation completed the drilling of the first well in Guyana, which reached a target depth of 9,812 feet measured depth within the Apoteri Formation on April 20, 2011. Light oil and gas shows were encountered within the Apoteri Formation, but due to poor reservoir quality, no reservoir fluids were recovered during drill stem testing. The K-2 well was subsequently abandoned.

The Corporation, along with its Joint Venture partners, are prospectivity evaluating the results of the K-2 exploration well and its impact on the remaining prospectivity of the block prior to making the decision of which of the remaining prospects to drill. The operator is currently in discussion with the Guyanese government to extend the current exploration phase to May, 2012 in order to drill the second commitment well. Total net cost for the second exploration well is anticipated to be \$8,500.

Brazil E&P

Canacol’s Brazilian operations are primarily engaged in the exploration of oil and gas.

Reconcavo Basin

Block 170 (75% operated working interest)

The Corporation has completed the process of acquiring the operator's interest and operatorship in the REC170 contract, giving the Corporation a 75% operated working interest and operatorship in the contract. The Corporation plans to drill 1 exploration well on the block in first half of 2012. Total net cost for the exploration well is anticipated at \$3,000.

The prospect contains four stacked reservoir sandstones that management estimates may contain up to 12 million barrels of gross mean unrisked recoverable light oil resource. The preferred well location is situated updip from an old well that recovered light oil from one of the sandstone intervals.

Canada and Ireland E&P

Operations in Canada are considered to be non-core. The Corporation continues to hold minor interests in some non-producing properties and is seeking to dispose of its interest in these remaining properties. The Corporation does not expect to receive any significant proceeds from the sale of the remaining interests and is not planning any operations activities for these Canadian interests.

Exploration in Ireland is considered to be non-core and high risk and includes oil and natural gas exploration and the potential for development of salt cavern gas storage. The Corporation is currently reviewing potential alternatives for its Ireland interests and currently has no planned activity in Ireland.

FINANCIAL HIGHLIGHTS AND SUMMARY OF RESULTS

Unless otherwise stated, amounts presented in this MD&A are in thousand of United State dollars (\$) or US\$. All discussions under the financial highlights section relate to oil and gas exploration and production operations of the Corporation.

OPERATING RESULTS	For the three months ended June 30,				For the year ended June 30,					
	2011		2010		2011		2010			
	Colombia	Brazil (1)	Colombia	Brazil (1)	Colombia	Brazil (1)	Colombia	Brazil (1)		
	Non-Tariff	Tariff			Non-Tariff	Tariff				
Sales Volume										
Crude oil and NGLs (bbl/d)	3,879	-	98	1,204	120	2,764	-	118	539	115
Tariff sales (bbl/d)	-	7,656	-	1,407	-	-	4,165	-	1,432	-
Production										
Crude oil and NGLs (bbl/d)	3,773	-	98	1,439	120	2,704	-	118	701	121
Tariff production (bbl/d)	-	7,652	-	1,152	-	-	4,229	-	1,432	-
Average sale prices										
Crude oil and NGLs (\$/bbl) ⁽⁵⁾	111.61	-	138.48	74.13	86.12	94.45	-	104.68	68.60	82.77
Operating netback (US\$/bbls)										
Commodity sales revenue ^{(2) (3)}	111.61	-	138.48	74.13	86.12	94.45	-	104.68	68.60	82.77
Tariff revenue	-	13.89	-	11.94	-	-	13.76	-	12.08	-
Tariff transportation reimbursement	-	-	-	-	-	-	0.15	-	-	-
Non-refundable sales taxes	-	-	(6.02)	-	(4.63)	-	-	(4.30)	-	(4.10)
Royalties	(8.93)	-	(9.65)	(5.72)	(5.67)	(7.56)	-	(6.85)	(5.37)	(5.80)
Well workover & repair	-	-	-	(2.24)	-	(0.11)	(0.12)	-	(1.11)	-
MEP work unit provision	-	-	-	-	(17.97)	-	-	-	-	(4.49)
Operating and transportation expenses ⁽⁴⁾	(31.52)	(4.89)	(60.96)	(21.44)	(37.95)	(30.32)	(4.09)	(49.35)	(15.02)	(46.12)
Operating netback ⁽⁵⁾	71.16	9.00	61.85	44.73	19.90	56.46	9.70	44.18	47.10	22.26

⁽¹⁾ Brazil results were estimated based on Agencia Nacional do Petroleo "ANP" data.

⁽²⁾ Prior year Colombian commodity sales revenue and tariff revenue include transportation revenue.

⁽³⁾ The Corporation had natural gas sales of approximately \$164 and \$723 during the three and twelve months ended June 30, 2011, respectively. This balance was included in crude oil sales as the balance represents less than 1% of the total revenue.

⁽⁴⁾ Prior year Colombian operating expenses relate to both tariff and non-tariff oil production

⁽⁵⁾ "Netback" per boe is calculated as revenues net of sales taxes and royalties, less transportation & processing charges, well workover and repair and operating expenses and then divided by bbls sold. Netbacks do not have a standard meaning prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. Management feels this is a useful metric as it is a common metric used by other companies operating in the oil and gas industry in order to provide a comparison of relative overall performance between companies. Management uses the metric to assess the Corporation's overall performance relative to that of its competitors and for internal planning purposes.

Average Daily Crude Oil Production and Sales

Average oil production and sales increased during the three months ended June 30, 2011 compared to Q4-F2010, as a result of the Corporation's continued drilling success on the Rancho Hermoso field in Colombia. Actual sales may be different from production volumes due to crude oil in transit at the period end date recorded in inventory.

FINANCIAL RESULTS (US\$000s), except share data	For the three months ended June 30,		For the year ended June 30,	
	2011	2010	2011	2010
Crude oil and NGL sales, net				
Colombia ⁽¹⁾	36,241	4,485	87,658	12,466
Brazil ⁽²⁾	1,098	845	4,022	3,246
	37,339	5,330	91,680	15,712
Tariff revenue	9,676	1,874	21,144	6,336
Interest and other revenue	880	212	1,574	792
Total revenue	47,895	7,416	114,398	22,840
Cash flow from (used in) operating activities,				
before change in non-cash operating working capital	11,200	(1,443)	38,405	(3,715)
Per share - basic and diluted	0.02	(0.00)	0.08	(0.01)
Adjusted cash flow from (used in) operating activities,				
before change in non-cash operating working capital ⁽³⁾	21,588	(1,443)	48,793	(3,715)
Per share - basic and diluted	0.04	(0.00)	0.11	(0.01)
Net income (loss)	8,916	(11,048)	(10,863)	(21,646)
Per share - basic and diluted	0.02	(0.03)	(0.02)	(0.07)
Capital expenditures				
Colombia	20,644	4,179	59,306	18,191
Brazil	325	275	1,237	2,465
Guyana	3,706	1,635	12,498	4,833
Canada	149	-	340	-
	24,824	6,089	73,381	25,489
Total assets	315,833	158,762	315,833	158,762
Total long-term liabilities	36,306	11,908	36,306	11,908
Weighted average shares outstanding				
Basic (000s)	504,291	383,873	464,110	299,785
Diluted (000s)	538,149	383,873	464,110	299,785

⁽¹⁾ Under the terms of one of Canacol's crude oil marketing agreements ("the Hocol agreement"), Canacol retains ownership of oil in transit until it reaches the export pipeline which can take several days at which point the ownership of the oil transfers from Canacol to Hocol. At June 30, 2011, there were 131,560 bbls of oil in transit. These barrels have been included in the Corporation's production volumes. However, revenue of approximately \$2,939 and expenses of \$1,790 associated with these barrels will be reported in July when title transfer occurs.

⁽²⁾ Brazil results were estimated based on Agencia Nacional do Petroleo "ANP" data.

⁽³⁾ The Corporation is required to pay current income taxes based on total volume sold, rather than just volumes which it is entitled to. As a result, the Corporation has recorded additional current tax expense of \$10,388 related to such volumes. Although this treatment has no impact on net loss, cash flows from operations are significantly affected. In the opinion of management, this adjusted cash flow from operating activities before non-cash operating working capital, after adjustment for current taxes described above better reflects the ongoing operations of Corporation. This measure is not a recognized performance measure under GAAP. For further discussion, refer to cash flows from operating on page 16.

Quarterly Information - Recurring Operations
(US\$000s, except production data and per share)

	F2011				F2010			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Crude oil and NGLs sales ^{(1) (2)}								
Colombia	36,241	22,321	14,735	14,361	4,485	3,722	2,063	2,196
Brazil	1,098	1,131	934	859	845	1,270	585	546
Total production revenue	37,339	23,452	15,669	15,220	5,330	4,992	2,648	2,742
Tariff revenue	9,676	8,677	1,212	1,579	1,874	1,607	1,611	1,244
Interest and other	880	196	247	251	212	165	265	150
Total operating revenue	47,895	32,325	17,128	17,050	7,416	6,764	4,524	4,136
Total production (bbl)	352,276	284,757	221,104	171,655	141,905	77,219	40,797	40,427
Total tariff production (bbl)	696,288	632,084	102,427	112,788	104,839	139,370	151,907	126,673
Cash from (used in) operating activities,								
before changes in non-cash operating working capital	11,200	18,024	1,829	7,352	(1,443)	(1,161)	(132)	(979)
Per share	0.02	0.04	0.03	0.00	(0.01)	(0.02)	0.01	(0.00)
Adjusted cash from (used in) operating activities								
before changes in non-cash operating working capital	21,588	18,024	1,829	7,352	(1,443)	(1,161)	(132)	(979)
Per share	0.04	0.04	0.03	0.00	(0.01)	(0.02)	0.01	(0.00)
Net (loss) income	8,916	(3,343)	(13,835)	(2,601)	(11,048)	(5,130)	(4,157)	(1,311)
Per share	0.02	(0.01)	(0.03)	(0.01)	(0.03)	(0.02)	(0.01)	(0.01)
Total assets	315,833	266,498	185,635	179,149	158,762	96,066	102,728	80,633
Total long term liabilities	36,306	26,253	26,651	33,314	11,908	17,537	21,573	23,413

⁽¹⁾ Under the terms of one of Canacol's crude oil marketing agreements ("the Hocol agreement"), Canacol retains ownership of oil in transit until it reaches the export pipeline which can take several days at which point the ownership of the oil transfers from Canacol to Hocol. At June 30, 2011, there were 131,560 bbls of oil in transit. These barrels have been included in the Corporation's production volumes. However, revenue of approximately \$2,939 and expenses of \$1,790 associated with these barrels will be reported in July when title transfer occurs.

⁽²⁾ The Corporation had natural gas sales of approximately \$164 and \$723 during the three and twelve months ended June 30, 2011, respectively.

⁽³⁾ The Corporation is required to pay current income taxes based on total volume sold, rather than just volumes which it is entitled to. As a result, the Corporation has recorded additional current tax expense of \$10,388 related to such volumes. Although this treatment has no impact on net loss, cash flows from operations are significantly affected. In the opinion of management, this adjusted cash flow from operating activities before non-cash operating working capital, after adjustment for current taxes described above better reflects the ongoing operations of Corporation. This measure is not a recognized performance measure under GAAP. For further discussion, refer to cash flows from operating on page 16.

Crude Oil and NGL (Net of Royalties)

The Corporation has three types of sales agreements in Colombia:

- **Tariff (Rancho Hermoso Field - Mirador formation)** - a risk service contract with Ecopetrol where the Corporation receives a fixed tariff price per barrel plus reimbursement of transportation charges;
- **Production revenue (Rancho Hermoso and Entrerrios Field - all other formations)** - a risk participation contract where the Corporation is entitled to approximately 25% of production after Ecopetrol's share and ANH royalties. Ecopetrol's share and ANH royalties are taken in kind; and
- **Production revenue (Capella Field)** - based on WTI less ANH royalties. The royalties are taken in kind (Refer to Royalties table on page 13).

Operating revenue for the three months ended June 30, 2011 totalled \$47,895 (Q4-F2010 - \$7,416), representing an increase of \$40,479 or 546% compared to Q4-F2010. Operating revenue for the year ended June 30, 2011 was \$114,398 (year ended June 30, 2010 - \$22,840) representing an increase of \$91,558 or 401% compared to the year ended June 30, 2010.

Operating revenue consists of production revenue (non-tariff production), tariff production and interest and other revenue. The production revenue during Q4-F2011 totalled \$37,339 (Q4-F2010 - \$5,330) representing an increase of \$32,009 or 601% compared to Q4-F2010. For the year ended June 30, 2011, production revenue was \$91,680 (year ended June 30, 2010 - \$15,712) representing an increase of \$75,968 or 484% compared to the year ended June 30, 2010. Tariff revenue during Q4-F2011 totalled \$9,676 (Q4-F2010 - \$1,874) representing an increase of \$7,802 or 416% compared to Q4-F2010. For the year ended June 30, 2011 tariff revenue was \$21,144 (year ended June 30, 2010 - \$6,336) representing an increase of \$14,808 or 234% compared to the year ended June 30, 2010.

The increase in operating revenue for Q4-F2011 compared to Q4-F2010 is due to higher production volumes achieved by the Corporation and a higher pricing environment.

In Colombia, sales volumes of crude oil achieved during the three months ended June 30, 2011 totalled 352,945 bbls (3,879 bbl/d) (Q4-F2010 - 109,600 bbls (1,204 bbl/d)). Sales volumes for the year ended June 30, 2011 totalled 1,008,795 bbls (2,764 bbl/d) (year ended June 30, 2010 totalled 196,800 bbls (539 bbl/d)). The average price achieved in Colombia in Q4-F2011 was \$111.61/bbl compared to \$74.13/bbl in Q4-F2010.

In Colombia, tariff sales volumes during Q4-F2011 totalled 696,663 bbls (7,656 bbl/d) (Q4-F2010 - 100,800 bbls (1,407 bbl/d)). For the year ended June 30, 2011, tariff sales totalled 1,520,249 bbls (4,165 bbl/d) (year ended June 30, 2010 - 513,497 bbls (1,432 bbl/d)). The average tariff price for Q4-F2011 was \$13.89/bbl; Q4-F2010 was \$11.94/bbl.

The increase in sales volumes for Q4-F2011 compared to Q4-F2010 was due to the start up of RH-6, RH-7, RH-8, RH-9, and RH-10.

Brazil sales volumes during Q4-F2011 totalled 8,941 bbls of light oil (98 bbl/d); (Q4-F2010 - 10,924 bbls (120 bbl/d)). For the year ended June 30, 2011, Brazil sales were 43,002 bbls (118 bbl/d) (year ended June 30, 2010 - 42,055 bbls (115 bbl/d)). The average price achieved per bbl in Brazil in the Q4-F2011 was \$138.48/bbl (Q4-F2010 - \$86.12/bbl) including transportation reimbursement.

Sales Volumes (bbls)	For the three months ended		For the year ended	
	June 30,		June 30,	
	2011	2010	2011	2010
Colombia	352,945	109,600	1,008,795	196,800
Brazil	8,941	10,924	43,002	42,055
Total net sales	361,886	120,524	1,051,797	238,855
Tariff sales	696,663	100,800	1,520,249	513,497
Total	1,058,549	221,324	2,572,046	752,352

Royalties as a percentage of gross crude oil and NGL sales by geographic region for the three months ended June 30, 2011 and the year ended June 30, 2010 prior period comparables are shown in the table below. The current base royalty regime in Brazil averages between 5% and 13% of gross production revenue. The actual rate the Corporation achieved for the three months ended June 30, 2011 in Brazil was 7.4% compared to 7.9% during Q4-F2010. In Brazil, royalty rates are based on a sliding scale on incremental production over and above certain production thresholds, calculated on a block by block basis. Therefore, if aggregate production on any one block increases above the contracted thresholds, the royalty on that block should decline over time. In Colombia, royalties are taken in kind and at a rate of approximately 8%. During Q4-F2011 Colombian royalties averaged 8%.

Royalties	Three months ended June 30,		Year ended June 30,	
	2011	2010	2011	2010
Colombia ⁽¹⁾	8.0%	8.0%	8.0%	8.0%
Brazil	7.4%	7.9%	6.6%	8.4%

⁽¹⁾ There are no royalties on tariff production.

Brazil oil sales are subject to non-refundable sales taxes. This totalled \$54 during three months ended June 30, 2011 (Q4-F2010 - \$52). For the year ended June 30, 2011, non-refundable sales taxes were \$185 (year ended June 30, 2010 - \$183). These have been recorded and netted against revenue for the three months ended June 30, 2011 and for the year ended June 30, 2011.

Interest and Other Revenue

During the three months ended June 30, 2011 Interest and Other Revenue of \$880 (Q4-2010 - \$212) was recorded while for the year ended June 30, 2011 \$1,574 (During the year ended June 30, 2010 - \$792). The increase in the Interest and Other Revenue compared to Q4-F2010 was due to an increase in interest earned on cash investments.

Operating and Transportation Expenses

For the three months ended June 30, 2011, operating expenses totalled \$15,084 (Q4-F010 - \$6,506). For the year ended June 30, 2011, operating expenses totalled \$39,213 (year ended June 30, 2010 - \$16,166). Colombian operating expenses relate to both tariff and non-tariff oil production. The production expenses increased during the year ended June 30, 2011 compared to the same period in 2010 as a result of higher costs for equipment rental facilities and increases in transportation costs due to higher production volumes and temporary increases in transport distances to deliver oil. Details by operating segment are outlined in the table below.

Operating Expenses (\$000s)	Three months ended June 30,		Year ended June 30,	
	2011	2010	2011	2010
Operating expenses				
Colombia ⁽¹⁾⁽²⁾	7,085	3,782	24,821	9,818
Brazil ⁽²⁾	415	412	1,488	1,494
	7,500	4,194	26,309	11,312
Colombia transportation & processing charges	7,452	1,501	11,977	3,219
Colombia well workover & repair	-	451	292	826
Brazil transportation & processing charges	132	160	635	609
MEP work unit provision	-	200	-	200
	15,084	6,506	39,213	16,166
Operating expenses per bbls				
Colombia ⁽¹⁾ Tariff	4.89	-	4.09	-
Non-Tariff	31.52	21.44	30.32	15.02
Brazil ⁽¹⁾	60.96	37.95	49.35	46.12
Weighted Average	14.24	19.08	15.03	13.79

⁽¹⁾ Expenditures related to the planned non-routine enhancement workover program undertaken are presented separately and excluded from the calculation of ongoing

Depletion, Depreciation, and Amortization (DD&A)

For the three months ended June 30, 2011, DD&A totalled \$9,988 (Q4-F2010 - \$3,817) while for the year ended June 30, 2011, overall DD&A expense was \$32,463 (year ended June 30, 2010 - \$11,817). Depletion expense is calculated on a unit of production basis. The depletion rate for the Colombia operations was \$9.34 per barrel for the three months ended June 30, 2011 (Q4-F2010 - \$14.73). Depreciation expense is calculated on a straight-line basis. Accretion expense is calculated as a present-value calculation of the Corporation's Asset Retirement Obligation. The increase in the depletion expense is a result of higher production volumes achieved by the Corporation.

General and Administrative

For the three months ended June 30, 2011, general and administrative (G&A) expenses were \$3,066 (Q4-F2010 - \$2,723) while for year ended June 30, 2011, overall G&A expense was \$13,995 (year ended June 30, 2010 - \$9,046). The increase in the G&A is primarily due to increases in personnel costs and professional fees to support expanding operations. G&A expenses are incurred in Canada, Colombia and Brazil and primarily consist of management and advisory fees, professional fees, travel, and other administrative expenses needed to support the Corporation's growing operations.

Interest and Financial Expense

For the three months ended June 30, 2011, Interest and Financial Expense was \$183 (Q4-F2010 - \$2,464). For the year ended June 30, 2011, Interest and Financial Expenses were \$3,409 (year ended June 30, 2010 - \$4,686). Interest and Financial Expense is comprised of interest on the Corporation's long-term debt facilities, lines of credit, and non-cash interest charges. Non-cash interest charges relate to the 8% and 12% convertible debentures and the accretion of the 8% and 12% convertible debentures. Non-cash interest charges for Q4-F2011 totalled \$994 (Q4- F2010 - \$767) while the non-cash interest charges for the year ended June 30, 2011 totalled \$1,278 (year ended June 30, 2010 - \$1,715).

Foreign Exchange

A portion of the Corporation's business in Colombia and Brazil is conducted in their respective currencies and therefore the Corporation is exposed to the risk of fluctuations in foreign exchange rates. The Corporation's sales contracts for oil produced in Brazil and Colombia are based on US dollar reference prices but are paid in Brazilian Real in Brazil and through a combination of US dollars and Colombian Pesos in Colombia. The Corporation's line of credit facilities are denominated in Colombian Pesos.

For the three months ended June 30, 2011, the Corporation incurred a net foreign exchange gain of \$2,231 (Q4-F2010 - loss of \$762). For the year ended June 30, 2011, the Corporation incurred a net exchange gain of \$2,976 (year ended June 30, 2010 - \$ 1,291). The foreign exchange gain for the three months ended June 30, 2011 is a result of the appreciation of the Canadian dollar relative to the US dollar, and the corresponding impact on the translation of the Brazilian operations from the Brazilian Real to U.S. Dollars.

Commodity Contracts

For the three months ended June 30, 2011, the Corporation had four commodity contracts in place. The WTI oil financial option collars have expiry dates in August through November 2011. The Corporation has not designated these derivatives as hedges and has therefore recorded the unrealized gain on the contract on the balance sheet with changes in its fair value recorded in the net earnings for the period. Refer to the Risk Factors section for specific details of the financial derivative contracts.

At June 30, 2011, the Corporation had a total net commodity contract liability of \$577 (June 30, 2010 - asset of \$227) relating to the oil financial option collars.

For the three months ended June 30, 2011, the Corporation had a net gain on commodity contracts of \$2,866 (Q4-F2010 - \$828) on its oil collar. For the year ended June 30, 2011, the Corporation had a net loss on commodity contracts of \$1,812 (year ended June 30, 2010 - gain of \$677). The Corporation had a realized net loss on its commodity contracts during the year ended June 30, 2011 due to higher realized oil prices.

Stock Based Compensation

For the three months ended June 30, 2011, a total of \$3,955 (Q4-F2010 - \$1,050) was expensed while for the year ended June 30, 2011, a total of \$12,202 was expensed (year ended June 30, 2010 - \$3,453). The year-over-year increase can primarily be attributed to a combination of the relative timing of options granted during the quarter, the vesting of previously granted options, and the assessed value of the options issued.

Overlifting Volumes

Included in overlifted volume payable is a provision, under a participation contract with Ecopetrol S.A. and approved by Ecopetrol, for repayment in barrels to Ecopetrol to replace volumes of crude oil sold for the Corporation's account due to the participant's pipeline transportation and storage constraints during the period. The market value of the liability of \$38,199 has been estimated as at June 30, 2011, based on the overlifted volume of 368,393 barrels.

During the year ended June 30, 2011, the Corporation had incurred \$4,024 (June 30, 2011 - nil) in transportation costs related to the delivery of overlifted volumes. Such costs are recorded as prepaid transportation on overlifted volumes and will be charged to earnings at the time the overlifted volumes are settled and the corresponding revenues are recognized.

During the year ended June 30, 2011, the Corporation recorded an unrealized loss on the payable on overlifted volumes of \$5,093 (June 30, 2010 - nil) related to the net change in the fair value of the liability recorded at June 30, 2011 compared to its previous carrying value.

Income Taxes

Canacol is subject to taxation in Canada, Brazil, and Colombia. The Corporation's pre-tax income is subject to Colombian income tax at a statutory rate of 33%. The Corporation is also subject to Colombian presumptive and equity taxes, both of which are based on capitalization level in Colombia. The effective tax rates are lower than the statutory rates due to the results of the deductions for the acquisition of certain capital assets.

The current income tax expense for three months ended June 30, 2011 was an expense of \$16,545 (Q4-F2010 - recovery of \$96), relating to Colombian income taxes. During the year ended June 30, 2011, current income tax expense was \$20,797 (year ended June 30, 2010 - \$1,159). Due to operating losses in Brazil and Canada, the Corporation was not subject to income taxes in these jurisdictions during the three and year ended June 30, 2011.

A future income tax asset is not recognized for the Corporation's Canadian net capital losses, non-capital loss, or other tax pool balances. Further, a future income tax asset has not been recognized on the Corporation's Brazilian tax losses or other tax pools. A valuation allowance for Canada and Brazil has conservatively been applied to the remainder of the future income tax assets in the entity due to uncertainty of realization.

As at June 30, 2011, the Company had a net deferred income tax asset of \$7,725. A majority of this balance relates to payables deferred income tax assets on overlifted volumes less deferred tax liability recorded on the book value in excess of the tax basis value on its petroleum and natural gas assets acquired through the acquisition of Canacol Energy Inc.

CASH FLOWS FROM OPERATING, FINANCING, AND INVESTING ACTIVITIES

Operating

For the three month period ending June 30, 2011, cash flow from operating activities before changes in non-cash working capital totalled an inflow of \$11,200 (Q4-F2010 - outflow of \$1,443) while for the year ended June 30, 2011, it totalled an inflow of \$38,405 (year ended June 30, 2010 - outflow of \$3,715).

Adjusted Operating

During the three months and year ended June 30, 2011, under a participation contract with Ecopetrol S.A., Ecopetrol was unable to take delivery of all production volumes it was entitled to. As a result, the Corporation sold such overlifted volumes and recorded a corresponding liability to Ecopetrol, which is contractually repayable in kind. The Corporation is currently discussing with Ecopetrol to repay the overlifting liability and to minimize its impact in future periods. The Corporation is

required to pay current year income taxes based on total volumes sold, rather than just volumes to which it is entitled to. Further, a tax deduction for the cost of the oil is not available for the liability provision until such overlifted volumes are returned in kind or repaid in cash. As a result, the Corporation has recorded additional current tax expense of \$10,388 related to such volumes, with a related future income tax recovery for the tax deduction available in future periods. Although this treatment has no impact on net loss, cash flows from operations for the three months and year ended June 30, 2011 are significantly affected. In the opinion of management, this treatment does not adequately reflect the ongoing operations of the Corporation.

Presented below is a reconciliation of cash flows from operating activities, before changes in working capital to adjusted cash flows from operating activities, before changes in working capital, after adjustment for the current tax matter described above. Adjusted cash flows from operating activities, before changes in working capital is not a recognized performance measure under GAAP and does not have a standardized meaning prescribed by GAAP. However, in the opinion of management, this measure better reflects the ongoing operations of Corporation and its related cash flow.

	For the three months ended June 30,		For the year ended June 30,	
	2011	2010	2011	2010
Adjusted cash flow from operations <i>(US\$000s)</i>				
Cash flow from operating activities, before changes in non-cash operating working capital	11,200	(1,443)	38,405	(3,715)
Add:				
Income tax on overlifted barrels, recoverable in future periods	10,388	-	10,388	-
Adjusted cash flow from operating activities, before changes in non-cash operating working capital	21,588	(1,443)	48,793	(3,715)

Financing

For the three months ended June 30, 2011, the Corporation recorded net cash outflow from financing activities of \$1,059 (Q4-F2010 -\$42,747). For the year ended June 30, 2011, the Corporation recorded net cash inflow from financing activities of \$98,289 (year ended June 30, 2010 - \$74,002). Cash inflow from financing activities for the three and year ended June 30, 2011 primarily relates to an equity financing that closed in February 2011 and the issuance of 8% convertible debentures.

Investing

For the three months ended June 30, 2011, cash flows from investing activities totalled an outflow of \$34,669 (Q4-F2010 - outflow of \$8,010). For the year ended June 30, 2011, cash flow from investing activities totalled an outflow of \$103,674 (year ended June 30, 2010 - \$17,321). For the year ended June 30, 2011, the Corporation incurred \$73,381 (year ended June 30, 2010 - \$25,489) in capital expenditures. A majority of the capital spent was related to the Corporation's Colombian and Guyana operations.

LIQUIDITY AND CAPITAL RESOURCES

Management believes that a combination of cash on hand, plus the cash generated from operating activities plus funding through debt or equity financing or potential farm-outs will enable the Corporation to execute its planned drilling programs and exploration commitments in Colombia, Guyana and Brazil.

Working Capital

Funding for the Corporation's expenditures during the three and year ended June 30, 2011 was provided by cash on hand, the issuance of 8% convertible debentures, equity financing and cash generated from operating activities. At June 30, 2011, the Corporation had positive working capital of \$91,548 (June 30, 2010 -\$34,315).

COMMITMENTS, GUARANTEES AND OFF-BALANCE SHEET ARRANGEMENTS

Minimum exploration program (Brazil)

As at June 30, 2011, the Corporation had minimum exploration program (“MEP”) work unit commitments to complete negotiated exploration work on its onshore blocks awarded by the Agência Nacional do Petróleo, Gás Natural e Biocombustível (“ANP”), Brazil’s National Petroleum Agency. MEP work units are satisfied through completion of exploration wells, seismic programs, and other exploration survey methods all of which have prescribed work units for completion. Therefore, although actual dollars spent on projects do not directly correlate to reducing the MEP work units, the financial guarantees related to non-performance are shown in the table below. The commitment is reduced as work is performed.

Bid Round	Basin/Block	Commitment Date	Extension	Gross Remaining MEP		Net Remaining MEP		Net Financial Guarantee ¹
				Work Units	Gross Financial Guarantee	Work Units	Gross Financial Guarantee	
					\$1,923			\$721
9	Recôncavo - Block 170 ²	June 5, 2010	(special extension)	1,000	BRL \$3,000	375	BRL \$1,125	\$231
9	Recôncavo - Block 169 ³	March 12, 2011	December 2, 2011	600	BRL \$1,800	120	BRL \$360	

¹ Net financial guarantee based on currently Canacol’s net working interest. Canacol acquired the operator’s interest and operatorship in the REC-T-170 contract in July 2011, which upon completion will give the Corporation a 75% operated working interest and an operatorship contract.

² ANP has granted a special extension to the Corporation on the agreement BT-REC-60, Block-T-170. Block 170 expires six months after permitting approval is received from the landowner to access the land. The negotiations are expected to commence shortly.

³ Block 169 will be relinquished to the ANP in October 2011. The Corporation will pay the MEP work units equivalent to \$231 (BRL \$360).

The round 9 (Reconcavo Basin) commitments are planned to be satisfied through a combination of the execution of an exploration drilling program and through financial settlement of MEP work units.

Work program commitments (Colombia)

Round 10

The Corporation has secured two Exploration and Production Contracts (“E&P Contracts”) in the Upper Magdalena Basin of Colombia via its wholly owned subsidiary Rancho Hermoso S.A.. Canacol secured 100% operated working interest in each of COR-11 and COR 39 E&P contracts which were awarded by the Agencia Nacional de Hidrocarburos (“ANH”). Each of the two blocks has a six year exploration term divided into two 36 month exploration phases. The Phase 1 work program commitments associated with each of these blocks are summarized below:

Bid Round	Basin	Commitment Date	Block	Working Interest	Work program commitments	Financial Guarantee ¹
10	Upper Magdalena Basin	July 1, 2013	COR -11	100%	155 kms of 2D seismic and 1 exploration well	\$ 12,200
10	Upper Magdalena Basin	July 1, 2013	COR-39	100%	90 kms of 2D seismic and 2 exploration wells	\$ 15,600

¹ The Corporation has placed a total of \$9,100 in letters of credit with ANH in July 2011 related to the Phase 1 work program commitments associated with each of the blocks above.

The Corporation signed three agreements with the ANH in February 2011 (Sangretoro, COR 11 and COR 39). The Sangretoro, E&P contract is located in the Putumayo - Caguan Basin of southern Colombia, and was previously part of the Pacarana Technical Evaluation Area (“TEA”) that was awarded in 2009 to the Corporation. The Phase 1 commitment associated with the Sangretoro block is summarized below:

Phase	Basin	Commitment Date	Working Interest	Work program commitments	Financial Guarantee
1	Putumayo-Caguan Basin	August 31, 2012	100%	300 kms of 2D seismic	\$ 6,000

Cedrela E&P Contract

On May 2010, the Corporation was awarded the Cedrela Exploration and Production Contract (“Cedrela E&P Contract”) by the ANH of Colombia. The Cedrela E&P contract is located in the Putumayo-Caguan Basin, and is approximately 50 kilometres directly southwest of the Ombu E&P contract which contains the Capella heavy oil discovery. The Corporation has a 100% working interest in the Cedrela E&P Contract, which is 129,418 hectares (319,799 acres) in size. The terms of the 6 year contract are as follows:

Phase	Basin	Commitment Date	Working Interest	Work program commitments	Financial Guarantee
1	Putumayo-Caguan Basin	December 31, 2011	100%	250 kms of 2D seismic	\$ 5,400
2	Putumayo-Caguan Basin	June 30, 2013	100%	Drill 1 exploration well	\$2,000
3	Putumayo-Caguan Basin	December 31, 2014	100%	60 kms of 3D seismic	\$3,000
4	Putumayo-Caguan Basin	June 30, 2016	100%	Drill 1 exploration well	\$2,000

Based on the results of the Phase 1 exploration activities, the Corporation has the option to proceed to the Phase 2 exploration period and associated activities or relinquish the contract. This option also applies to phase 3 and 4.

Other Commitments

In Guyana, the Corporation has work program commitments totalling approximately \$8,500 due within a year or less. The operator is currently in discussion with the Guyanese government to extend the current exploration phase to May, 2012 in order to drill the second commitment well.

In addition, the Corporation has commitments for leases and its office premises. As of June 30, 2011, the payments required in each of the next five calendar years on these lease are as follows:

Leases	\$
2011	276
2012	552
2013	440
2014	109
2015	65

The disposition of the Corporation’s non-core Brazil properties was approved by the Brazilian authorities and was closed subsequent to June 30, 2011. As adequate supporting financial documents have not been provided by the operator, the Corporation continues to record revenues, expenses and any amounts receivable from or payable to the operator using the Corporation’s best estimates as of June 30, 2011. Any adjustments required upon final settlement in the joint venture operation will be recorded in the first quarter of the fiscal year 2012.

PENDING LAND AUCTION AWARD TRANSACTIONS

Round 8 Land Auction

The Corporation qualified for and bid for onshore land blocks offered by the ANP, Brazil’s National Petroleum Agency in Brazil’s Round 8 land auction held on November 28th and 29th, 2006 (“Round 8 Bid”). Canacol was successful in winning and being awarded two separate blocks, each block totalling 180 square kilometres of exploration lands (“Round 8 Bid Lands”) in the Tucano Basin which lies

directly west of the Recôncavo Basin. However, the Round 8 Bid is the subject of a court injunction filed in Brasilia against the ANP. The premise for the injunction is that the restriction for any one E&P company to purchase more than four blocks of land in any one area, in any given bid round of land is not constitutional. As of this report date, the court injunction has been lifted in the superior court from one of two jurisdictions. Canacol has no information indicating that its successful Round 8 Bid Lands will not be retained by the Corporation.

No capital commitments are currently included in Canacol's capital budget for the round 8 lands.

SUBSEQUENT EVENTS

Discussed in relevant sections in this MD&A.

OUTLOOK

Canacol's goal is to build a significant oil production and exploration company in Latin America. The Corporation has established a production platform in its core operating areas in Colombia, along with large onshore appraisal and exploration positions in Colombia, Brazil, and Guyana. The Corporation is using its strong technical management team to realize the full production and reserves potential of its producing assets. In Colombia, the Corporation has identified a number of low risk opportunities within its operated fields that it intends to pursue, which are expected to result in significant increases in existing production and reserves. With current production levels increasing faster than originally expected due to better than anticipated performance from the recently drilled wells at Rancho Hermoso, the Corporation revised its guidance upward from previously disclosed average of 10,000 to 11,000 bbl/d to a new target of 10,500 to 11,500 bbl/d for calendar 2011.

On August 31, 2011, the Corporation announced that Canacol Energy Colombia S.A., a subsidiary of the Corporation, had been awarded a contract by Ecopetrol S.A. for a 100% working interest in the associated gas and gas liquids stream from the Rancho Hermoso Field, located in the Llanos Basin of Colombia. Under the terms of the contract, awarded to Canacol by Ecopetrol S.A. on August 31, 2011, the Corporation will purchase the produced gas from Ecopetrol S.A. at a price of US\$ 6.50 per thousand British Thermal Units (US\$ 15.48 per thousand standard cubic feet per day), which includes the associated liquids, those being naphtha, propane and butane. The gas is liquids rich, with 1 million standard cubic feet per day (mmscfpd) yielding approximately 160 barrels of naphtha, 126 barrels of propane, and 118 barrels of butane per day. In Colombia naphtha, propane, and butane all sell at a premium to West Texas Intermediate. The 5 year contract will be effective on January 1, 2012. Renewal of the contracts if economically attractive, would be negotiated at the end of the contract.

On the exploration side, the Corporation has met with success in its non-operated Ombu E&P contract in Colombia, with the discovery of the Capella oil field. This significant discovery, currently being appraised, is expected to yield near term production and reserves gains, and represents a long term development project with large heavy oil reserves upside.

The Corporation plans to drill a total 4 developments wells at its Rancho Hermoso field during the second half of calendar 2011, 5 wells on its 3 heavy oil exploration contracts in the Caguan (Sangretoro, Cedrela, and Tamarin) located close to Capella starting in the third calendar quarter of 2011 through to midyear 2012. The Corporation will also participate in the drilling of 3 exploration wells on the Coati and Andaquies E&P contracts located in the Putumayo Basin operated by C&C Energia in the fourth calendar quarter of 2011.

The Corporation is also planning to drill an exploratory well in the Rewa block in Guyana to fulfill its drilling commitments at an estimated cost of \$8,500 prior to May, 2012 pending approval of the current exploration phase by the Guyanese government.

SHARES OUTSTANDING (as at September 26, 2011)

There are an unlimited number of no par value common shares authorized for issuance. Details of the issued and outstanding shares are as follows:

Issued & Outstanding Share Capital

Number of shares issued and outstanding, June 30, 2011	511,636,603
Signing bonuses	69,999
Stock options exercised	405,000
Debentures converted	833,331
Interest on debentures paid through issuance of shares	8,519
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Number of shares issued and outstanding, September 26, 2011	512,953,452

OPTIONS OUTSTANDING (as at September 26, 2011)

The following are the outstanding stock options issued by the Corporation and their respective exercise prices and expiry dates. At September 26, 2011, vested options totalling 20,843,606 options were exercisable at a weighted average exercise price of \$0.65 per common share and a total of 41,895,437 options were issued and outstanding at a weighted average exercise price of \$0.84.

Stock Options Outstanding

	Number	Weighted Average Exercise Price	Expiry Date Range
Balance, June 30, 2011	34,167,937	\$0.81	
Option Grants	8,162,500	\$0.94	July 4- Sept 1, 2016
Cancelled & Expired Options	(30,000)	\$1.54	January 24, 2016
Exercised	(210,000)	\$0.10	January 6, 2014
	(70,000)	\$0.20	June 5, 2014
	(125,000)	\$0.91	July 20, 2015
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Balance, September 26, 2011	41,895,437	\$0.84	

WARRANTS OUTSTANDING (as at September 26, 2011)

As part of the May 14 and 28, 2009 private placements, 24,000,000 warrants were issued. Each warrant entitled the holder to acquire one common share at a price of \$0.18 (C\$0.20) until May 14, 2011 (first closing) and May 28, 2011 (second closing). All of these warrants have been exercised as of June 30, 2011.

On July 23, 2009, the Corporation issued 1,109,524 warrants in connection with a private placement at an exercise price of \$0.28 (C\$0.30). In addition, the Corporation issued 1,500,000 warrants in connection with the sale of a promissory note receivable at an exercise price of \$0.28 (C\$0.30) for 18 months. All of these warrants have been exercised as of June 30, 2011.

RISK FACTORS

The Corporation is subject to several risk factors including, but not limited to: the volatility of oil and natural gas prices; foreign exchange and currency risks; general risks related to foreign operations such as political, economic, regulatory and other uncertainties as they relate to both foreign investment policies and energy policies; governments exercising from time to time significant influence on the economy to control inflation; developing environmental regulations in foreign jurisdictions; discovery of new oil and natural gas reserves; concentration of oil sales receipts with a few major customers; substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the long-term for which additional financings may be required to implement Canacol's business plan.

As the Corporation has not experienced sufficient positive cash flow from operations to independently finance its growth and operations, it has been reliant on access to capital in the form of both debt and equity to fund on-going operations and to fund capital investments. Although periodic volatility of financial and capital markets may severely limit access to capital, the Corporation has been able to successfully attract the required investment capital.

The Corporation is exposed to foreign exchange and currency risk as a result of fluctuations in exchange rates through its cash deposits and investments denominated in the Colombian Peso (COP\$), the Brazil Real (BRL\$), and the Canadian dollar (C\$) as well as its debt balances which are denominated in US\$.

Much of the Corporation's revenue and exploration and development costs are expected to be received/paid in reference to US\$ denominated prices while a significant portion of its operating and general and administrative costs are denominated in Canadian dollars, the BRL\$, and the COP\$. As a result of ongoing adverse conditions, the Brazilian Real and the Colombian Peso have seen significant variation against the US\$ during 2010 and 2011 and it continues to have significant daily fluctuations making this particular currency risk more acute. The Corporation has not entered into any currency derivatives in order to reduce its exposure to fluctuations the US Dollar may incur.

The Corporation, through its wholly owned subsidiary Canacol Energy Colombia S.A. has revolving operating lines of credit. These lines of credit bear interest at the Depósitos a Término Fijo ("DTF") interest rate, a Colombian benchmark interest rate, plus spreads of 2% per annum on the balance outstanding resulting in an average rate of 6% for the year ended June 30, 2011 (June 30, 2010 - average of 9.5%). As at June 30, 2011, the Corporation has unsecured revolving lines of credit with an aggregate borrowing base of \$32,134 (COP\$ 57.2 billion). These lines of credit have interest rates ranging from 6% to 9%. The Corporation has not drawn any amounts under these lines of credit.

Fluctuations in energy prices will not only impact revenues of the Corporation but may also affect lending policies of the Corporation's lenders for existing and new borrowings. Crude oil prices are correlated with overall global economic growth and activity. The continuing volatility in the global economic environment has resulted in significant variation in crude oil prices over the last year. Any dramatic drop in crude oil prices will have a negative impact on the profitability of the Corporation which in turn will impact the operational cash flows of the Corporation as well as on its ability to finance capital expenditures. In absence of externally-sourced capital, this could limit growth prospects over the short run or may even require the Corporation to dispose of assets.

The Corporation entered into four oil price financial derivative collars with the following terms.

WTI crude oil financial option collar:

Period	Volume	Type	Price Range
Jan 2010 – Aug 2011	114 bbls/day	Financial WTI Oil Collar	US\$55.00 - US\$80.25
May 2010 – Aug 2011	500 bbls/day	Financial WTI Oil Collar	US\$70.00 - US\$100.45
Nov 2010 – Oct 2011	500 bbls/day	Financial WTI Oil Collar	US\$70.00 - US\$100.00
Dec 2010 – Nov 2011	500 bbls/day	Financial WTI Oil Collar	US\$70.00 - US\$100.00

The fair value of these transactions is based upon the estimated amounts that would have been paid to or received from counter parties in order to settle the transactions outstanding with reference to the forward prices as of the reporting date. The contracts have been transacted with a counter party with whom management has assessed credit risk and deemed no adjustment for credit risk is required in determining the estimated settlement price. In addition, the contracts are based on standard industry contracts and the Corporation does not feel that there is a liquidity risk associated with them and no adjustment has been recorded in computing their valuation. While commodity contract activities may have opportunity costs when realized prices exceed commodity contract pricing, such transactions are not meant to be speculative and are considered within the broader framework of financial stability and flexibility. Management continuously reviews the need to utilize such techniques.

The Corporation's policy is to enter into agreements with customers that are well established and well-financed entities in the oil and gas industry such that the level of risk associated with one or more of its customers facing financial difficulties are mitigated while balancing factors of economic dependence with profit maximizing. To date, the Corporation has not experienced any material credit loss in the collection of accounts receivable. All Brazilian oil sales made through the Joint Venture are to a single customer who is the government energy company (Petrobras), while in Colombia the majority of oil sales revenue and tariff oil revenue comes from three customers of which two are also government entities (Petrobras Colombia and Ecopetrol) and Hocol controlled by Ecopetrol.

The Corporation attempts to mitigate its business and operational risk exposures by maintaining comprehensive insurance coverage on its assets and operations, by employing or contracting competent technicians and professionals, by instituting and maintaining operational health, safety and environmental standards and procedures and by maintaining a prudent approach to exploration and development activities. The Corporation also addresses and regularly reports on the impact of risks to its shareholders, writing down the carrying values of assets that may not be recoverable.

CRITICAL ACCOUNTING ESTIMATES

Canacol's significant accounting policies are contained in Note 2 to the audited consolidated financial statements for the year ended June 30, 2011.

Currency translation

The accounts of the self-sustaining Canadian parent are translated using the current rate method, whereby assets and liabilities are translated at the period-end exchange rates and revenues and expenses are translated using average period exchange rates. Translation gains and losses relating to the self-sustaining operations are included as part of accumulated other comprehensive income. The Corporation continues to use the temporal method to translate the operations of its Brazilian subsidiaries as detailed in the Corporation's annual consolidated financial statements. Colombian subsidiaries are self-sustained and have U.S. dollar functional currencies. The Guyana subsidiary has a U.S. dollar functional currency.

Revenue recognition

The Corporation receives tariff revenue under a risk service contract with Ecopetrol in which a tariff price per barrel of tariff oil production is paid to the Corporation. Ecopetrol is a Mixed Economy Company, with a commercial orientation, organized as an "Anonymous Society" (equivalent to a Corporation), under the Ministry of Mines and governed by the Social Statutes. Ecopetrol S.A. carries out hydrocarbon exploration, production, and transportation activities in Colombia both directly and through participation agreements with other companies operating in Colombia. The Corporation recognizes revenue based on production of tariff oil and collection is reasonably assured.

All contracts that Canacol Energy Colombia S.A. ("CECSA") (formerly Rancho Hermoso S.A. ("RHSA")) has signed with Ecopetrol are "risk contracts" because CECSA makes all investments and is in charge of producing at its own cost and risk. CECSA takes the risk regardless of the outcome. However, there are differences depending how the contract rewards CECSA. There are two cases:

In the case of production from the Mirador formation in the RHSA field, it is a service contract because all of the crude belongs to Ecopetrol and CECSA gets paid through a tariff per barrel. CECSA provides the service for oil production. This is referred to as a Risk Service Contract.

In the other cases (such as Ubaque in Rancho Hermoso and all formations in Entrerrios), the contract is a participation contract because CECSA is entitled to a proportion of the production. Therefore, CECSA gets paid its share of the oil production sold in the market. This is referred to as a Risk Participation Contract.

Exploration contracts refer to activities that the Corporation performs to determine the existence and location of hydrocarbons in the subsurface, including but not limited to geophysical and geochemical methods, and other operations to determine whether the discovery is a commercial field.

With regards to the Corporation's accounting policies, certain policies are recognized as critical because in applying these policies management is required to make judgments, assumptions, and estimates that have a significant impact on the financial results of the Corporation. The estimates used in applying these critical accounting policies are regularly reviewed and have been discussed with the Audit Committee. These policies include:

Income taxes

The Corporation uses the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are based on the differences between asset and liability balances reported for financial accounting purposes and those reported for income tax. Future income tax assets and liabilities are measured using the substantively enacted tax rates expected to apply in the years in which the temporary differences are expected to be recovered or settled. Future income tax assets are recognized to the extent that they are more likely than not to be realized.

Property, plant, and equipment

Depletion and depreciation

Petroleum and natural gas properties are recorded in accordance with the Canadian Institute of Chartered Accountants' guideline on full cost accounting for the oil and gas industry whereby all costs relating to the exploration and development of petroleum and natural gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical costs, costs of drilling both productive and non-productive wells, production equipment, and overhead charges directly related to acquisition, exploration, and development activities. Gains or losses on disposal of properties are recognized only when crediting the proceeds to the recorded costs would result in a change of 20% or more in the depletion and depreciation rate.

Ceiling test and unproved properties

An impairment loss is recognized in net earnings when the carrying amount of a cost centre of petroleum and natural gas assets and properties is not recoverable and the carrying amount of the cost centre exceeds its fair value. The carrying amount of the cost centre is tested for recoverability

by determining if the carrying amount exceeds the sum of the undiscounted cash flow from proved reserves. If the sum of the cash flow is less than the carrying amount, the impairment loss is limited by the amount by which the carrying amount exceeds the sum of the fair value of the proved and probable reserves and the costs of unproved properties that are subject to a separate impairment test.

Certain costs related to unproved properties and major development projects are excluded from costs subject to depletion and depreciation until the earliest of a portion of the property becomes capable of production, development activity ceases, or impairment occurs. These properties are reviewed quarterly and are subject to a separate impairment test. Any impairment is transferred to the costs being depleted. If the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Asset retirement obligations

The fair value of the estimated asset retirement obligations is recognized in the consolidated balance sheet in the period which the liability is identified and incurred and a reasonable estimate of the fair value can be made. The obligations recognized are the legal obligations of the Corporation to retire and perform site restoration on tangible long-lived assets such as well sites. The obligations are discounted to their present value using the Corporation's credit adjusted risk-free interest rate. The corresponding amount increases the carrying amount of the related asset. The liability is accreted over time for changes in the fair value of the liability through charges to accretion expense. The amounts capitalized to the related assets are amortized to earnings over the expected remaining life of the underlying resources using the unit of production method. Actual costs incurred upon settlement of the asset retirement obligations are charged against the obligation to the extent of the liability recorded.

Stock based compensation plan

The Corporation records compensation expense in the consolidated financial statements for stock options granted to employees, directors, and consultants using the fair value method. Fair values are determined using the Black-Scholes option pricing model with compensation costs recognized over their vesting period. Any consideration paid to the Corporation on the exercise of stock options, along with amounts previously credited to Contributed Surplus, is credited to share capital.

Financial instruments

The Corporation's financial assets and liabilities consist of cash and cash equivalents, accounts receivable, accounts payable, accrued liabilities, convertible debentures, currency and commodity derivatives, and long-term debt. The fair value of these financial assets and liabilities approximates their carrying value, unless otherwise noted.

IMPACT OF NEW AND PROPOSED ACCOUNTING STANDARDS

International Financial Reporting Standards (IFRS)

Effective January 1, 2011, Canadian public companies are required to adopt International Financial Reporting Standards ("IFRS") which will include comparatives for 2010. Canacol's financial statements up to and including June 30, 2011 will continue to be reported in accordance with Canadian GAAP as it exists on each reporting date. Financial statements for the quarter ended September 30, 2011, including comparative amounts, will be prepared on an IFRS basis.

In order to transition to IFRS, management has established a project team. A transition plan has been developed to convert the financial statements to IFRS. External advisors have been retained and will continue to assist management with the project on an as needed basis. Training has been provided to key employees and staff training programs will continue as needed. The Company continues to assess the effect of the transition on information systems, internal controls over financial reporting and disclosure controls and procedures. Systems and controls are being updated as IFRS accounting

processes are implemented. Significant system and control changes are not anticipated. Calculations of the impact of changes in accounting policy are being prepared by management and will be approved by the Company's Board of Directors and the Company's auditors. The Company's auditors have been involved throughout the process to ensure the Company's policies are in accordance with the new standards.

There are significant accounting policy changes anticipated on adoption of IFRS which are described in more detail below. Most adjustments required on transition to IFRS will be made retrospectively against opening retained earnings as of the date of the first comparative balance sheet being July 1, 2010. In July 2009, the International Accounting Standards Board ("IASB") issued amendments to IFRS 1 "First time adoption of IFRS" allowing additional exemptions for first-time adopters. Under these amendments, full cost oil and gas companies can elect to use the recorded amount under a previous GAAP as the deemed cost for oil and gas assets on the transition date to IFRS. Canacol is planning to adopt this exemption.

IFRS Conversion Project Plan

The IFRS conversion project plan consists of three phases as identified below:

Phase 1 - Initial Scoping (Completed)

Canacol's Management team have undertaken a preliminary high-level scoping study to consider the potential impact of the implementation of IFRS on the Corporation's financial reporting. The initial scoping includes the identification of key differences between Canadian GAAP and IFRS, and high-level changes required in accounting policies, systems and processes.

Phase 2 - Detailed Assessment and Design (In progress)

Comprehensive documentation and analysis of changes in accounting standards, policies, processes and procedures identified on scoping from Phase 1.

Phase 3 - Implementation (In progress)

Implementation and execution of changes identified from Phase 2.

Potential Impact of IFRS Adoption

Significant differences that have been identified between Canadian GAAP and IFRS that will impact the Corporation's are:

- IFRS 1 - First -time adoption of IFRS;
- IAS 16 - Property, plant and equipment;
- IFRS 6 - Exploration and evaluation of mineral resources;
- IAS 36 - Impairment testing;
- IAS 37 - Provision, contingencies liabilities and contingencies assets (Decommissioning costs); and
- An increased level of disclosure requirements.

These differences have been identified based on the current IFRS standards issued and expected to be in effect on the date of transition. Certain IFRS standards may be modified, and as a result, the impact may be different than the Corporation's current expectations. Management is currently determining the financial statement impact of these standards. The impact on the consolidated financial statements is not reasonably determinable at this time.

IFRS 1 - First Time Adoption of IFRS

The transition to IFRS requires the Corporation to apply IFRS 1, which prescribes requirements for preparing IFRS compliant financial statements in the first reporting period after the changeover date (July 1, 2011). IFRS 1 includes a requirement for retrospective application of each IFRS standard as if they were always in effect. IFRS 1 also mandates certain exemptions for retrospective application and provides optional exemptions from retrospective application to ease the transition to IFRS in the transition year.

This standard will have a significant impact on Canacol's consolidated financial statements, at least from the perspective of reconciliation from Canadian GAAP to IFRS. However, this standard has the potential to be most complex to implement and have the greatest financial statement impact depending on policies choices made by Canacol.

IAS 16 - Property Plant and Equipment

This standard may have a high impact at Canacol. The most significant impact would occur should Canacol choose to account for some of its properties, plant and equipment using the revaluation model as many of the Corporation's capital assets are expected to have fair values that are significantly different than historical costs.

IFRS and Canadian GAAP contain the same basic principles of accounting for property, plant and equipment; however, differences in application do exist, specifically for oil and gas companies. IAS 16 requires costs recognized as property plant and equipment to be allocated to the significant parts of the asset and to amortize each significant component separately. This is a departure from Canadian GAAP for full cost oil and gas companies, and may increase the number of components to amortize separately, and could impact the amount of amortization expense.

The Corporation is currently evaluating the impact of this accounting standard.

IFRS 6 - Exploration and Evaluation Expenditures

IFRS 6 provides specific guidance with respect to recognition, measurement, presentation and disclosure requirements for costs incurred in the exploration phase. Unlike Canadian GAAP, IFRS requires the identification and presentation of exploration and evaluation expenditures to be separated from developed and producing assets. In addition, Canacol will be required to perform an impairment test on exploration and evaluation expenditures when there is a determination that the expenditures have resulted in a technically feasible and commercially viable project. At that time, the expenditures would be tested for impairment, and then transferred to the developed and producing assets category.

Canacol expects to be significantly impacted by this standard due to the highly specific accounting policies. The Corporation is currently evaluating its policy options and applicable impact of these policies under IFRS.

IAS 36 - Impairment of Assets

IAS 36 uses the concept of cash generating units to accumulate asset carrying costs to test and measure impairment.

Under IFRS, the Corporation will no longer test for asset impairment at the cost center level (country level) as permitted under the Canadian GAAP full cost guideline. IFRS will require impairment testing to be performed at the cash generating unit level, which is lower than the current cost center level.

In addition, IAS 36 uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of: value-in-use and fair value less costs to sell. Value-in-use is defined as the amount equal to the present value of future cash flows expected to be derived from the asset. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP, which uses undiscounted cash flows as an initial first step to test impairment.

Under IAS 36, impairment losses that were previously recognized may be reversed where circumstances change such that the impairment is reduced. This differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

The Corporation is currently evaluating the impact of this accounting standard.

IAS 37 - Decommissioning Costs

Under IFRS, the recognition criteria for contingent liabilities are much more explicit than Canadian GAAP and may potentially require the booking of additional liabilities associated with the asset retirement obligations of Canacol's oil and gas assets. Liabilities for decommissioning and restoration are recognized for both legal and constructive obligations. Under IFRS, the estimated liability is calculated at each reporting period using estimates of risk-adjusted future cash outflows, discounted using the risk free rate whereas under Canadian GAAP the estimated liability is estimated using a credit-adjusted rate, rather than a risk free rate.

Changes in the estimated timing of cash flows necessary to discharge the obligation are added to or deducted from the cost of the related asset and the adjusted amounts are amortized prospectively over the estimated useful life of the asset. The measurement of the present value of the estimate (arising due to different discount rates used) is likely to be higher under IFRS as compared to Canadian GAAP.

Information Systems

It is expected that the conversion to IFRS will have a minimal impact on the Canacol's information system.

MAINTENANCE OF DISCLOSURE CONTROLS AND PROCEDURES (DC&P) AND INTERNAL CONTROL OVER FINANCIAL REPORTING (ICFR)

Subsequent to the listing of the Corporation's stock on the Toronto Stock Exchange and the transition of the Corporation from a venture issuer status to a non-venture issuer, effective May 03, 2011, the Corporation has become subject to the full requirements of National Instrument ("NI") 52-109 as a non-venture issuer. Accordingly, commencing with the Corporation's first fiscal quarter (quarter ending September 30, 2011) following the quarter in which the Corporation became a non-venture issuer (quarter ended June 30, 2011), the certifying officers of the Corporation will be required to certify that they have designed and established DC&P and ICFR in accordance with an acceptable internal control framework. Furthermore, on an annual basis, effective June 30, 2012, the certifying officers of the Corporation will be required to certify that they have evaluated the effectiveness of the Corporation's DC&P and ICFR and have disclosed their conclusions about the effectiveness of such controls in the annual MD&A of the Corporation.

Under the provisions of NI 52-109, during the quarter that the venture issuers become a non-venture issuer, the certifying officers are not required to make any representations with respect to the design and maintenance of DC&P and ICFR. However, a Note to Reader must be provided to that effect in the basic certification issued for the quarter in which the Company becomes a non-venture issuer.

However, as indicated in the Form 52-109F1 - IPO/RTO Certification filed with the Corporation's Annual Information Form for the year ended June 30, 2011, management has established processes to ensure that they are provided with sufficient knowledge to support the representations made in the certificate that the annual filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, for the period covered by the annual filings and that the annual financial statements together with the other financial information included in the annual filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date of and for the periods presented in the annual filings.

Furthermore, management and the Board of Directors are committed to the promotion of investor confidence by ensuring that trading in the Corporation's securities takes place in an efficient, competitive, and informed market. In accordance with the continuous disclosure requirements under the securities commission rules, the Corporation has adopted a Corporate Disclosure Policy and has

procedures in place to ensure that any sensitive information is identified, reviewed by management, and disclosed in a timely manner to the regulatory authorities, shareholders, and the public.

In preparation for its full interim certification requirements as of September 30, 2011, management is in the process of documenting and assessing the design of its DC&P and ICFR.

ADDITIONAL INFORMATION

Additional information relating to the Corporation's regulatory filings can be found on SEDAR at www.sedar.com.

Corporate Information

Management Team

Charle Gamba – President & Chief Executive Officer
Mark Holliday – Chief Operating Officer
Mark Teare – Vice President, Exploration
Brian Hearst – Chief Financial Officer
Kevin Flick – Vice President, Capital Markets & Investor Relations
Luis Baena – Vice President, Business Development, Colombia

Board of Directors

Michael Hibberd, Chairman
Luis Baena
Alvaro Barrera
Jason Bednar
Charle Gamba
Stuart Hensman
David Winter

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Auditors

Deloitte & Touche LLP - Calgary, Alberta

Bankers

HSBC Bank Canada – Calgary, Canada
HSBC Bank Brasil - Rio de Janeiro, Brazil
Citibank - Bogotá, Colombia

Independent Reserve Engineers

DeGolyer and MacNaughton Canada Limited

Legal Counsel

Davis LLP - Canada
Schmidt, Valois, Miranda, Ferreira & Agel – Brazil
Salazar Asociados Abogados - Colombia

Stock Exchange Listings

Common shares:

Toronto Stock Exchange: CNE

BVC Colombia: CNE.C

8% Convertible Debentures:

Toronto Stock Exchange (Debentures): CNE.DB

Transfer Agent & Registrar

Olympia Trust Company
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Calgary, Alberta T2G 0P6

