CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE AND SIX MONTHS ENDED DECEMBER 31, 2014

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Petroleum and natural gas revenues, net of royalties	**36,404**	42,168	(14%)	**95,321**	90,390	5%
Adjusted petroleum and natural gas revenues, net of royalties, including revenues related to the Ecuador IPC (2)	**43,878**	47,101	(7%)	**111,234**	99,491	12%
Cash provided by operating activities	**31,743**	36,406	(13%)	**77,361**	56,130	38%
Per share – basic ($)	**0.29**	0.42	(31%)	**0.72**	0.65	11%
Per share – diluted ($)	**0.29**	0.41	(29%)	**0.71**	0.64	11%
Adjusted funds from operations (1) (2)	**22,952**	16,713	37%	**60,114**	41,759	44%
Per share – basic ($)	**0.21**	0.19	11%	**0.56**	0.48	17%
Per share –diluted ($)	**0.21**	0.19	11%	**0.55**	0.48	15%
Net income (loss)	**(45,970)**	(10,412)	342%	**(31,860)**	(7,431)	329%
Per share – basic and diluted ($)	**(0.43)**	(0.12)	258%	**(0.30)**	(0.09)	233%
Capital expenditures, net	**78,403**	22,749	245%	**125,925**	40,157	214%
Adjusted capital expenditures, net, including capital expenditures related to the Ecuador IPC (1)(2)	**87,228**	32,679	167%	**143,437**	56,422	154%
				December 31, 2014	June 30, 2014	Change
Cash and cash equivalents				**124,696**	163,729	(24%)
Restricted cash				**74,771**	66,827	12%
Working capital surplus, excluding the current portion of bank debt and non-cash items (1)				**78,824**	159,117	(50%)
Short-term and long-term bank debt				**244,580**	210,688	16%
Total assets				**757,948**	756,587	-
Common shares, end of period (000s)				**107,814**	107,736	-

Operating	Three months ended December 31,			Six months ended December 31,		
	2014	**2013**	Change	**2014**	**2013**	Change
Petroleum and natural gas **production**, before royalties (boepd)						
Petroleum (3)	**8,586**	6,998	23%	**9,254**	6,555	41%
Natural gas	**3,236**	3,097	4%	**3,285**	3,060	7%
Total (2)	**11,822**	10,095	17%	**12,539**	9,615	30%
Petroleum and natural gas **sales**, before royalties (boepd)						
Petroleum (3)	**8,187**	5,868	40%	**9,092**	6,088	49%
Natural gas	**3,216**	2,953	9%	**3,264**	3,003	9%
Total (2)	**11,403**	8,821	29%	**12,356**	9,091	36%
Realized sales prices ($/boe)						
LLA-23 (oil)	**58.62**	86.86	(33%)	**72.49**	89.81	(19%)
Esperanza (natural gas)	**25.12**	29.45	(15%)	**23.27**	29.56	(21%)
Ecuador (tariff oil) (2)	**38.54**	38.54	-	**38.54**	38.54	-
Total (2)	**45.55**	61.81	(26%)	**53.41**	63.64	(16%)
Operating netbacks ($/boe) (1)						
LLA-23 (oil)	**30.78**	64.68	(52%)	**43.50**	66.05	(34%)
Esperanza (natural gas)	**20.04**	24.56	(18%)	**18.41**	24.82	(26%)
Ecuador (tariff oil) (2)	**38.54**	38.54	-	**38.54**	38.54	-
Total (2)	**25.14**	38.44	(35%)	**31.89**	38.89	(18%)

(1) Non-IFRS measure – see "Non-IFRS Measures" section within MD&A.
(2) Inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section within MD&A.
(3) Includes tariff oil production and sales related to the Ecuador IPC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. and its subsidiaries ("Canacol" or the "Corporation") are primarily engaged in petroleum and natural gas exploration and development activities in Colombia and Ecuador, with non-core activities in Brazil and Peru. The Corporation's head office is located at 4500, 525 - 8th Avenue SW, Calgary, Alberta, T2P 1G1, Canada. The Corporation's shares are traded on the Toronto Stock Exchange under the symbol CNE, the OTCQX in the United States of America under the symbol CNNEF, and the Bolsa de Valores de Colombia under the symbol CNEC.

Advisories

The following management's discussion and analysis ("MD&A") is dated February 10, 2015 and is the Corporation's explanation of its financial performance for the period covered by the financial statements along with an analysis of the Corporation's financial position. Comments relate to and should be read in conjunction with the unaudited interim condensed consolidated financial statements of the Corporation for the three and six months ended December 31, 2014 and 2013 (the "financial statements"), and the audited consolidated financial statements and management's discussion and analysis for the year ended June 30, 2014. The financial statements have been prepared in accordance with International Accounting Standard 34, "Interim Financial Reporting", and all amounts herein are expressed in United States dollars, unless otherwise noted, and all tabular amounts are expressed in thousands of United States dollars, except per share amounts or as otherwise noted. Additional information for the Corporation, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

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

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

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

Non-IFRS Measures – *Due to the nature of the equity method of accounting the Corporation applies under IFRS 11 to its interest in the incremental production contract for the Libertador and Atacapi fields in Ecuador ("Ecuador IPC"), the Corporation does not record its proportionate share of revenues and expenditures as would be typical in oil and gas joint interest arrangements. Therefore, within this MD&A, management has provided supplemental measures of adjusted revenues and expenditures, which are inclusive of the Ecuador IPC, to supplement the IFRS disclosures of the Corporation's operations. Such supplemental measures should not be considered as an alternative to, or more meaningful than, the measures as determined in accordance with IFRS as an indicator of the Corporation's performance, and such measures may not be comparable to that reported by other companies.*

One of the benchmarks the Corporation uses to evaluate its performance is adjusted funds from operations. Adjusted funds from operations is a measure not defined in IFRS. It represents cash provided by operating activities before changes in non-cash working capital and decommissioning obligation expenditures, and includes the Corporation's proportionate interest of those items that would otherwise have contributed to funds from operations from the Ecuador IPC had it been accounted for under the proportionate consolidation method of accounting. The Corporation considers adjusted funds from operations a key measure as it demonstrates the ability of the business to generate the cash flow necessary to fund future growth through capital investment and to repay debt. Adjusted funds from operations should not be considered as an alternative to, or more meaningful than, cash provided by operating activities as determined in accordance with IFRS as an indicator of the Corporation's performance. The Corporation's determination of adjusted funds from operations may not be comparable to that reported by other companies. The Corporation also presents adjusted funds from operations per share, whereby per share amounts are calculated using weighted-average shares outstanding consistent with the calculation of earnings per share. The following table reconciles the Corporation's cash provided by operating activities to adjusted funds from operations:

	Three months ended December 31,		Six months ended December 31,	
	2014	2013	**2014**	2013
Cash provided by operating activities	**$ 31,743**	$ 36,406	**$ 77,361**	$ 56,130
Changes in non-cash working capital	**(15,712)**	(24,626)	**(31,962)**	(23,472)
Ecuador IPC revenue, net of current income tax	**6,921**	4,933	**14,715**	9,101
Adjusted funds from operations	**$ 22,952**	$ 16,713	**$ 60,114**	$ 41,759

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, excluding non-cash items such as the current portion of commodity contracts, the current portion of convertible debentures, the current portion of warrants, and the current portion of any embedded derivatives asset/liability, and is used to evaluate the Corporation's financial leverage. Operating netback is a benchmark common in the oil and gas industry and is calculated as total petroleum and natural gas sales, less royalties, less production and transportation expenses, calculated on a per barrel equivalent ("boe") basis of sales volumes using a conversion. Operating netback is an important measure in evaluating operational performance as it demonstrates field level profitability relative to current commodity prices.

Working capital and operating netback as presented do not have any standardized meaning prescribed by IFRS and therefore may not be comparable with the calculation of similar measures for other entities.

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

RESULTS OF OPERATIONS

For the three months ended December 31, 2014, the Corporation's production primarily consisted of crude oil from its Leono, Labrador, Pantro and Tigro fields in the Llanos Basin in Colombia, natural gas from its Nelson field in the Lower Magdalena Basin in Colombia, tariff oil from the Ecuador IPC, and, to a lesser extent, crude oil from its Rancho Hermoso, Capella, VMM-2 and Santa Isabel properties in Colombia.

During the three months ended December 31, 2014, the Corporation acquired a 100% interest in the VIM-5 and VIM-19 Exploration and Production ("E&P") contracts from OGX Petroleo E Gas S.A. Both contracts are located in the vicinity of the Esperanza block in the Lower Magdalena Basin of Colombia. The first well drilled in the VIM-5 E&P contract in November 2014, Clarinete-1, encountered 149 feet of potential gas pay in the primary Cienaga de Oro sandstone reservoir, the same reservoir that the Corporation produces from its Nelson and Palmer gas fields on the adjacent Esperanza contract and has tested at a combined gross rate of 45.3 million standard cubic feet per day ("MMcfpd") (7,947 barrels of oil equivalent per day "boepd") of dry gas with no water in the two planned production tests over two separate reservoir intervals. The gross unrisked pre drill best estimate for the Clarinete prospect as per the Gaffney Cline and Associates ("GCA") prospective resource report is 540 billion cubic feet ("bcf") of gas. Ten additional prospects and leads identified within the VIM-5 and VIM-19 E&P contracts contain a significant volume of prospective resource assuming all prospects are drilled according to a July 2014 NI 51-101 compliant report from GCA. In addition, Pursuant to an existing agreement, and subject to approval from the ANH, an industry joint venture partner has the ability to earn up to 25% of the Corporation's 100% interest in exchange for fulfilling certain financial commitments.

In February 2015, the Corporation executed a new 15 year take or pay contract for the sale of 35 million British thermal units ("MMbtu") (6,140 boepd) of gas to Altenesol Colombia S.A.S ("Altenesol") commencing in the third quarter of calendar 2016. Under the terms of the contract, Altenesol will pay $4.90/MMbtu ($27.93/boe), escalated at 2% per year across the term of the contract. In addition, Canacol and Altenesol executed an agreement pursuant to which Canacol has the option, valid for six months from the agreement date, to participate in the revenues generated by the sale of the Liquefied Natural Gas ("LNG") through an equity ownership position in Altenesol of approximately 26% in exchange for investing $13 million in the project. Altenesol will use the gas to produce approximately 360,000 gallons of LNG per day at a dedicated liquefaction facility to be located close to Canacol's operated Jobo gas processing facility. Altenesol has recently executed a 15 year take or pay contract to sell the LNG to be produced by the facility to a large international distributor for export to markets in the Caribbean at a sales price of approximately $11/MMbtu ($62.70/boe) at the sales point of Cartagena in Colombia. Canacol, through its beneficial ownership of Altenesol, will also derive revenues from the sale of the LNG of approximately $1.25/MMbtu ($7.12/boe). As such, total revenues from the gas sales contract and Canacol's beneficial ownership in Altenesol are expected to be approximately $6.25/MMbtu ($35.63/boe) escalated at 2% per year across the 15 year tenure of the take or pay contract. The gas for the contract is expected to come from the recently discovered Clarinete gas field located on the VIM 5 E&P Contract.

The Esperanza block, located in the Lower Magdalena Basin in Colombia, produces dry natural gas for sale to local customers under long-term contracts. As previously disclosed, the Corporation has executed three new gas sales contracts for a combined 65 MMcfpd which will take Canacol's current daily gas production of approximately 20 MMcfpd (3,509 boepd) to 83 MMcfpd (14,561 boepd) in late calendar 2015. The new contracts each have a five year term, with pricing of $ 5.40/MMbtu escalated at 2% per year for two of the contracts totalling 35 MMcfpd, and $8.00/MMbtu escalated at approximately 3% per year for the third contract of 30 MMcfpd. Canacol currently sells approximately 18 MMcfpd (3,158 boepd) of gas from the Nelson Field to a local ferronickel producer under a 10 year contract that expires in 2021. That contract was linked to the Guajira price index, which changed effective October 29, 2014 from $3.97/MMbtu ($22.63/boe) to $5.08/MMbtu ($28.96/boe). Nevertheless, as mentioned above, the Corporation has diversified its future gas sales with the addition of three new fixed-price gas contracts commencing in December 2015. The Corporation has also completed the drilling of a second gas exploration well on the Esperanza contract, Corozo-1, in early October 2014, which has been cased and is awaiting production testing. Upon making the Clarinete-1 and Corozo-1 gas discoveries in November 2014, and more importantly based upon the significant gas resource potential of the Clarinete discovery, the Corporation decided to defer the drilling of the Canandonga-1 exploration well, and instead drilled the Nelson-5 development well at its operated Nelson gas field. The Nelson-5 well encountered 117 feet of net gas pay within the Cienaga de Oro sandstone, the main producing reservoir within the Nelson gas field, with an average porosity of 22%. The Nelson-5 well is currently being tied in to the gas gathering system at the Nelson field. The existing Nelson and Palmer wells are expected to have sufficient productive capacity to deliver the 83 MMcfpd of contracted gas by the end of calendar 2015.

The Corporation, through a consortium, participates in an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation receives a tariff price of $38.54/bbl for each incremental barrel of oil produced over a pre-determined production base curve. Such incremental production volumes are reported as production in this MD&A. As further described above, as required under IFRS 11, the Ecuador IPC is being accounted for under the equity method of accounting versus the proportionate consolidation method of accounting. For purposes of this MD&A, management has provided supplemental measures for adjusted revenues and expenditures, which are inclusive of the Ecuador IPC, to supplement the IFRS disclosures of the Corporation's operations. During the quarter ended December 31, 2014, the Corporation participated in the drilling of two new development wells and the work over of three existing wells to add new production.

Both gas sales from Esperanza (currently sold based on Guajira price index of $5.08/MMbtu or $28.96/boe) and tariff oil from Ecuador ($38.54/bbl), together comprising approximately 44% of production in the three months ended December 31, 2014, are insensitive to world oil prices, offering the Corporation a significant degree of protection from the effects of low benchmark oil prices.

Over the past two years the Corporation has made five key light oil discoveries on its LLA-23 block located in the Llanos basin, those being Labrador in December 2012, Leono in December 2013, Pantro in April 2014, Tigro in August 2014, and most recently Maltes in January 2015. These discoveries are currently producing just under half of the Corporation's current production. The Corporation completed the Labrador-6 and Tigro-3 development wells and the drilling and testing of the Maltes-1 discovery well during the quarter ended December 31, 2014. The Maltes-1 discovery well tested a gross rate of 1,555 barrels of oil per day ("bopd") of 32° API light oil (1,400 bopd net) from the C7 sandstone reservoir with a water cut of less than 1% using an electrical submersible pump operating at a frequency of 38 Hz at the end of a six day flow test. The Maltes-1 discovery well will be left on long term production, subject to the approval of the ANH. The Corporation is also moving along with the acquisition of a 400 square kilometer 3D seismic program which commenced in August 2014. The objective of the 3D seismic program is to firm up the portfolio of 12 currently identified exploration leads into prospects for drilling in calendar 2015 and 2016.

For the three months ended December 31, 2014, the Corporation also had other crude oil production from its Rancho Hermoso, Capella, VMM-2 and Santa Isabel properties in Colombia. Rancho Hermoso is a mature field and its production and netbacks have become immaterial to the consolidated results overall. At VMM-2, the Corporation and its partner have completed the drilling of the Mono Arana-9 appraisal well into the shallow Lisama discovery during the quarter ended December 31, 2014, which is awaiting production testing. The Corporation's Rancho Hermoso, Capella, VMM-2 and Santa Isabel properties individually contributed only a minor amount to total production in the quarter ended December 31, 2014 and, therefore, they were aggregated into a single group for analysis purposes in this MD&A. These properties are susceptible to negative cash flows in a low oil price environment and the Corporation plans to shut-in any wells under its control that are uneconomic.

In addition to its producing fields, the Corporation has interests in a number of exploration blocks in Colombia and Peru.

Average Daily Petroleum and Natural Gas Production and Sales Volumes

Production and sales volumes in this MD&A are reported before royalties.

	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Production (boepd)						
LLA-23 (oil)	**4,953**	3,705	34%	**5,314**	3,365	58%
Esperanza (gas)	**3,236**	3,097	4%	**3,285**	3,060	7%
Ecuador (tariff oil)	**1,967**	1,077	83%	**2,120**	1,018	108%
Rancho Hermoso and other (oil and liquids)	**1,666**	2,216	(25%)	**1,820**	2,172	(16%)
Total production	**11,822**	10,095	17%	**12,539**	9,615	30%
Inventory movements, power generation and other	**(419)**	(1,274)	(67%)	**(183)**	(524)	(65%)
Total sales	**11,403**	8,821	29%	**12,356**	9,091	36%
Sales (boepd)						
LLA-23 (oil)	**4,744**	2,874	65%	**5,240**	3,089	70%
Esperanza (gas)	**3,216**	2,953	9%	**3,264**	3,003	9%
Ecuador (tariff oil)	**1,967**	1,077	83%	**2,120**	1,018	108%
Rancho Hermoso and other (oil and liquids)	**1,476**	1,917	(23%)	**1,732**	1,981	(13%)
Total sales	**11,403**	8,821	29%	**12,356**	9,091	36%

The overall increase in production volumes in the three and six months ended December 31, 2014 compared to the same periods in 2013 is primarily due to new production from the Labrador, Leono, Pantro and Tigro discoveries on the LLA-23 block, production increases from the Libertador and Atacapi fields in Ecuador, and new production from the Oso Pardo and Morsa discoveries on the Santa Isabel block.

Petroleum and Natural Gas Revenues

	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
LLA-23	**$ 25,584**	$ 22,967	11%	**$ 69,888**	$ 51,045	37%
Esperanza	**7,431**	8,002	(7%)	**13,973**	16,332	(14%)
Rancho Hermoso and other	**7,794**	15,375	(49%)	**22,531**	31,858	(29%)
Petroleum and natural gas revenues, before royalties	**40,809**	46,344	(12%)	**106,392**	99,235	7%
Royalties	**(4,405)**	(4,176)	5%	**(11,071)**	(8,845)	25%
Petroleum and natural gas revenues, after royalties, as reported	**36,404**	42,168	(14%)	**95,321**	90,390	5%
Ecuador tariff and other revenues	**7,474**	4,933	52%	**15,913**	9,101	75%
Adjusted petroleum and natural gas revenues, after royalties [(1)]	**$ 43,878**	$ 47,101	(7%)	**$ 111,234**	$ 99,491	12%

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see “Non-IFRS Measures” section above.

The decrease in adjusted petroleum and natural gas revenues in the three months ended December 31, 2014 compared to the same period in 2013 is primarily the result of the increased overall sales of 29% by volume, offset by the impact of lower realized average prices during the quarter as a result of declines in benchmark crude oil prices. The increase in adjusted petroleum and natural gas revenues in the six months ended December 31, 2014 compared to the same period in 2013 is primarily the result of the increased overall sales of 36% by volume, offset by the impact of lower realized average prices during the quarter.

Average Benchmark and Realized Sales Prices

	Three months ended December 31,					Six months ended December 31,				
		2014		2013	Change		**2014**		2013	Change
Brent ($/bbl)	**$**	**76.43**	$	109.23	(30%)	**$**	**89.16**	$	109.73	(19%)
West Texas Intermediate ($/bbl)	**$**	**73.21**	$	97.50	(25%)	**$**	**85.54**	$	101.66	(16%)
LLA-23 ($/bbl)	**$**	**58.62**	$	86.86	(33%)	**$**	**72.49**	$	89.81	(19%)
Esperanza ($/boe)		**25.12**		29.45	(15%)		**23.27**		29.56	(21%)
Ecuador ($/bbl)		**38.54**		38.54	-		**38.54**		38.54	-
Rancho Hermoso and other ($/bbl)		**57.40**		87.18	(34%)		**70.68**		87.40	(19%)
Average realized sales price ($/boe) (1)	**$**	**45.55**	$	61.81	(26%)	**$**	**53.41**	$	63.64	(16%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

In January 2014, the Guajira Index, the natural gas reference price used as a basis for the calculation of the Corporation's current Esperanza sales contracts, was reduced to $3.97/MMbtu ($22.63/boe) by decree of the "Comision de Regulacion de Energia y Gas" ("CREG") of Colombia. The decree was made by the CREG as part of temporary measures involved in bridging the time from January 1, 2014, when certain amendments to the applicable legislation in Colombia came into force, and the establishment of a "market regulator" that will be in charge of calculating and publishing a Guarjira average price as mandated by such legislation.

As of October 29, 2014, the market regulator has been established and the Guajira Index has been revised up to $5.08/MMbtu ($28.96/boe). Nevertheless, the Corporation has diversified its future gas sales with the addition of three new fixed-price gas contracts commencing in December 2015 for 65 MMcfpd (11,404 boepd) for a five year period at a fixed price of $5.40/MMbtu (escalated at approximately 2% per year) for 35 MMcfpd, under contracts executed in December 2013, and $8.00/MMbtu (escalated at approximately 3% per year) for 30 MMcfpd under the most recent contract executed in September 2014.

Royalties

	Three months ended December 31,				Six months ended December 31,			
		2014		2013		**2014**		2013
LLA-23	**$**	**3,117**	$	2,254	**$**	**8,025**	$	4,963
Esperanza		**605**		709		**1,167**		1,371
Rancho Hermoso and other		**683**		1,213		**1,879**		2,511
Total royalties	**$**	**4,405**	$	4,176	**$**	**11,071**	$	8,845

In Colombia, crude oil royalties are generally at a rate of 8% until net field production reaches 5,000 boepd, then increase on a sliding scale to 20% up to field production of 125,000 boepd. Crude oil royalties in Labrador and Rancho Hermoso are taken in kind. The Corporation's LLA-23 and VMM-2 blocks are subject to an additional x-factor royalty of 3% (effectively 2.76%). Crude oil royalties in LLA-23 and VMM-2 are calculated from crude oil revenue net of transportation expenses. The Corporation's Capella heavy oil field is subject to a 6% royalty. There are no royalties on tariff production in Ecuador. Natural gas royalties are calculated from natural gas revenue, generally at a rate of 6.4%. In addition, the Corporation's natural gas production is subject to an additional overriding royalty of 2%.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended December 31,					Six months ended December 31,				
		2014		2013	Change		**2014**		2013	Change
Production expenses	**$**	**15,342**	$	11,308	36%	**$**	**33,578**	$	24,308	38%
Transportation expenses		**1,667**		3,482	(52%)		**4,263**		8,243	(48%)
Total production and transportation expenses	**$**	**17,009**	$	14,790	15%	**$**	**37,841**	$	32,551	16%
$/boe	**$**	**16.21**	$	18.22	(11%)	**$**	**16.65**	$	19.46	(14%)

An analysis of production expenses is provided below:

	Three months ended December 31,					Six months ended December 31,				
		2014		2013	Change		**2014**		2013	Change
LLA-23	**$**	**8,365**	$	1,880	345%	**$**	**17,371**	$	5,027	246%
Esperanza		**900**		619	45%		**1,754**		1,249	40%
Rancho Hermoso and other		**6,077**		8,809	(31%)		**14,453**		18,032	(20%)
Total production expenses	**$**	**15,342**	$	11,308	36%	**$**	**33,578**	$	24,308	38%
$/boe										
LLA-23	**$**	**19.17**	$	7.11	170%	**$**	**18.02**	$	8.84	104%
Esperanza	**$**	**3.04**	$	2.28	33%	**$**	**2.92**	$	2.26	29%
Total	**$**	**14.62**	$	13.93	5%	**$**	**14.77**	$	14.53	2%

Production expenses at LLA-23 increased 345% and 246% in the three and six months ended December 31, 2014, respectively, compared to the same periods in 2013. The increase is primarily due to new production from the Labrador, Leono, Pantro and Tigro discoveries.

Production expenses at Esperanza increased 45% and 40% in the three and six months ended December 31, 2014, respectively, compared to the same periods in 2013, primarily due to increased production and higher labour and electricity generation costs.

Production expenses at Rancho Hermoso and other decreased 31% and 20% in the three and six months ended December 31, 2014, respectively, compared to the same periods in 2013. The decrease is primarily the result of decreased production in the Rancho Hermoso field. Under its contract with Ecopetrol, the Corporation pays 100% of the production expenses at Rancho Hermoso while only recognizing non-tariff production before royalties of approximately 24-25% of gross non-tariff production. As a result, production expenses for Rancho Hermoso oil are higher than a similar operation that is subject to an ANH contract, such as LLA-23, Capella, VMM-2 and Santa Isabel.

In light of the weakness in benchmark crude oil prices, the Corporation will focus its efforts to reduce production expenses in order to maintain profitability in its operations. The Corporation has successfully renegotiated some tariffs with its major service providers to reduce production expenses. Further, the Corporation is centralizing its production, loading, and water disposal operations from the different fields within the LLA-23 block to the Pointer platform; by doing so reducing operating expenses, transportation expenses and water handling costs via reinjection. In Rancho Hermoso, the Corporation continues to shut-in wells with high water cut which helps reduce overall power generation and water handling costs. The Corporation will continue to monitor its non-operated fields at VMM-2 and Capella and work with the operators to optimize profitability.

The Corporation does not pay production expenses in Ecuador.

An analysis of transportation expenses is provided below:

	Three months ended December 31,					Six months ended December 31,				
		2014		2013	Change		**2014**		2013	Change
LLA-23	**$**	**666**	$	1,733	(62%)	**$**	**2,551**	$	3,515	(27%)
Rancho Hermoso and other		**1,001**		1,749	(43%)		**1,712**		4,728	(64%)
Total transportation expenses	**$**	**1,667**	$	3,482	(52%)	**$**	**4,263**	$	8,243	(48%)
$/boe										
LLA-23	**$**	**1.53**	$	6.55	(77%)	**$**	**2.65**	$	6.18	(57%)
Total	**$**	**1.59**	$	4.29	(63%)	**$**	**1.88**	$	4.93	(62%)

Total transportation expenses have decreased by 52% and 48% in the three and six months ended December 31, 2014, respectively, compared to the same periods in 2013 mainly due to lower transportation rates, decreased sales volumes at Rancho Hermoso and other, and more delivery of crude oil at the field. The Corporation does not pay transportation costs at Esperanza or in Ecuador.

Operating Netbacks

$/boe	Three months ended December 31, 2014	2013	Change	Six months ended December 31, 2014	2013	Change
Petroleum and natural gas revenues	$ 45.55	$ 61.81	(26%)	$ 53.41	$ 63.64	(16%)
Royalties	(4.20)	(5.15)	(18%)	(4.87)	(5.29)	(8%)
Production and transportation expenses	(16.21)	(18.22)	(11%)	(16.65)	(19.46)	(14%)
Operating netback [(1)]	$ 25.14	$ 38.44	(35%)	$ 31.89	$ 38.89	(18%)

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

Operating netbacks by major production categories were as follows:

$/boe	Three months ended December 31, 2014	2013	Change	Six months ended December 31, 2014	2013	Change
LLA-23						
Crude oil revenues	$ 58.62	$ 86.86	(33%)	$ 72.49	$ 89.81	(19%)
Royalties	(7.14)	(8.52)	(16%)	(8.32)	(8.73)	(5%)
Production and transportation expenses	(20.70)	(13.66)	52%	(20.67)	(15.03)	38%
Operating netback	$ 30.78	$ 64.68	(52%)	$ 43.50	$ 66.05	(34%)
Esperanza						
Natural gas revenues	$ 25.12	$ 29.45	(15%)	$ 23.27	$ 29.56	(21%)
Royalties	(2.04)	(2.61)	(22%)	(1.94)	(2.48)	(22%)
Production expenses	(3.04)	(2.28)	33%	(2.92)	(2.26)	29%
Operating netback	$ 20.04	$ 24.56	(18%)	$ 18.41	$ 24.82	(26%)
Ecuador						
Tariff revenues [(1)]	$ 38.54	$ 38.54	-	$ 38.54	$ 38.54	-
Operating netback [(1)]	$ 38.54	$ 38.54	-	$ 38.54	$ 38.54	-

(1) Revenues related to the Ecuador IPC are not included in Petroleum and Natural Gas Revenues as reported under IFRS – see "Non-IFRS Measures" section above.

General and Administrative Expenses

	Three months ended December 31, 2014	2013	Change	Six months ended December 31, 2014	2013	Change
Gross costs	$ 8,440	$ 10,155	(17%)	$ 15,271	$ 16,054	(5%)
Less: capitalized amounts / reversal	(684)	(1,175)	(42%)	(1,617)	(1,663)	(3%)
General and administrative expenses	$ 7,756	$ 8,980	(14%)	$ 13,654	$ 14,391	(5%)
$/boe	$ 7.39	$ 11.07	(33%)	$ 6.01	$ 8.60	(30%)

Gross general and administrative expenses decreased 17% and 5% in the three and six months ended December 31, 2014, respectively, compared to same periods in 2013 primarily due to the Corporation's efforts to manage its general and administrative expenses in light of the recent weakness in benchmark crude oil prices. Accrued annual bonuses were included in general and administrative expenses for the three months ended December 31, 2014 and 2013 as compared to other quarters.

Net Finance Income and Expense

	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Net financing paid	**$ 4,007**	$ 1,579	154%	**$ 6,149**	$ 2,905	112%
Non-cash financing costs	**1,475**	627	135%	**2,721**	1,244	119%
Net finance expense	**$ 5,482**	$ 2,206	149%	**$ 8,870**	$ 4,149	114%

Net finance expense increased by 154% and 112% in the three and six months ended December 31, 2014, respectively, compared the same periods in 2013 primarily due to increased interest and financing costs incurred on the $220 million (2013 – $140 million) Senior Term Loan and the $50 million Senior Note (2013 – $ nil).

Commodity Contracts

During the three and six months ending December 31, 2014, the Corporation had one financial oil collars outstanding under the following terms:

Period	Volume	Type	Price Range
Jan 2014 – Dec 2014	500 bbls/day	Financial Brent Oil Collar	$75.00 – $123.50

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

	Three months ended December 31,		Six months ended December 31,	
	2014	2013	**2014**	2013
Unrealized change in fair value	**$ -**	$ (156)	**$ (38)**	$ (195)
Realized cash settlement	**(182)**	201	**(182)**	432
Total loss (gain)	**$ (182)**	$ 45	**$ (220)**	$ 237

Stock-Based Compensation Expense

	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Gross costs	**$ 2,523**	$ 778	224%	**$ 4,354**	$ 1,383	215%
Less: capitalized amounts	**(466)**	(259)	80%	**(1,029)**	(633)	63%
Stock-based compensation expense	**$ 2,057**	$ 519	296%	**$ 3,325**	$ 750	343%

Stock-based compensation expense is a non-cash expense that is based on the fair value of stock options granted. The fair value is calculated on grant date and amortized over the vesting period. On October 6, 2014, the board of directors approved the cancellation of 2,211,500 stock options granted on May 30, 2014 at a $7.21 exercise price to be re-priced. The options were re-priced on January 5, 2015 with an exercise price of C$2.21 with an additional 95,000 stock options granted to new employees.

Restricted Share Units

	Number	Amount
	(000s)	
Balance at June 30, 2014	62	$ 404
Granted	235	1,010
Settled	(8)	(38)
Unrealized gain	-	(693)
Foreign exchange gain	-	(66)
Balance at September 30, 2014	**289**	**$ 617**

On October 2, 2014, the Corporation granted 234,781 restricted share units ("RSUs") to certain directors and officers, with a reference price of C$4.80 per share. The RSUs vested as to one-half in six months and one-half in twelve months from the grant date, and will be settled in cash.

Depletion and Depreciation Expense

	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Depletion and depreciation expense	**$ 16,818**	$ 7,530	123%	**$ 36,311**	$ 14,828	145%
$/boe	**$ 16.03**	$ 9.28	73%	**$ 15.97**	$ 8.86	80%

Depletion and depreciation expense increased 123% and 145% in the three and six months ended December 31, 2014, respectively, compared to 2013 primarily as a result of the higher depletable base at LLA-23, Esperanza and Santa Isabel.

Impairment on Development Assets

	Three months ended December 31,		Six months ended December 31,	
	2014	2013	**2014**	2013
Impairment on development assets	**$ 27,396**	$ -	**$ 27,396**	$ -

In light of recent weakness in benchmark crude oil prices, impairment tests were carried out at December 31, 2014 using revised forecasted crude oil price estimates. The impairment tests resulted in a write-down primarily related to the Rancho Hermoso assets totalling $27.4 million as at December 31, 2014. The Corporation's core producing assets at Esperanza and LLA-23 were unaffected.

Income Tax Expense

	Three months ended December 31,		Six months ended December 31,	
	2014	2013	**2014**	2013
Current income tax expense (recovery)	**$ (1,403)**	$ 5,548	**$ 2,223**	$ 7,170
Deferred income tax expense (recovery)	**4,880**	(2,545)	**64**	(2,951)
Income tax expense (recovery)	**$ 3,477**	$ 3,003	**$ 2,287**	$ 4,219

The Corporation's pre-tax income is subject to the Colombian statutory income tax rate of 34%. The deferred income tax expenses of $4.9 million and $0.1 million in the three and six months ended December 31, 2014, respectively, was primarily attributable to the devaluation of the Colombian peso versus the United States dollar, offset by a deferred income tax recovery related to the impairment charge on certain development assets.

Cash and Funds from Operations and Net Income (Loss)

	Three months ended December 31,			Six months ended December 31,		
	2014	2013	Change	**2014**	2013	Change
Cash provided by operating activities	**$ 31,743**	$ 36,406	(13%)	**$ 77,361**	$ 56,130	38%
Per share – basic ($)	**$ 0.29**	$ 0.42	(31%)	**$ 0.72**	$ 0.65	11%
Per share – diluted ($)	**$ 0.29**	$ 0.41	(29%)	**$ 0.71**	$ 0.64	11%
Adjusted funds from operations (1)	**$ 22,952**	$ 16,713	37%	**$ 60,114**	$ 41,759	44%
Per share – basic ($)	**$ 0.21**	$ 0.19	11%	**$ 0.56**	$ 0.48	17%
Per share – diluted ($)	**$ 0.21**	$ 0.19	11%	**$ 0.55**	$ 0.48	15%
Net loss	**$ (45,970)**	$ (10,412)	342%	**$ (31,860)**	$ (7,431)	329%
Per share – basic and diluted ($)	**$ (0.43)**	$ (0.12)	258%	**$ (0.30)**	$ (0.09)	233%

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

The net loss of $46.0 million for the three months ended December 31, 2014 was driven by several non-cash items that did not affect the core business of the Corporation. In particular, significant devaluation of the Colombian peso versus the United States dollar in the quarter resulted in a non-cash deferred tax expense impact of approximately $22.4 million, while an impairment charge, primarily related to the mature and immaterial Rancho Hermoso property due to lower forecast crude oil prices, as well as losses on disposition of minor non-core assets resulted in a net loss impact of approximately $22.3 million.

Capital Expenditures

	Three months ended December 31,				Six months ended December 31,			
		2014		2013		2014		2013
Drilling and completions	$	41,163	$	17,304	$	77,028	$	28,172
Facilities, work overs and infrastructure		5,827		2,980		11,203		4,929
Seismic, capitalized general and administrative expenses, capitalized borrowing costs and other		12,987		2,465		19,268		7,056
Property acquisitions		37,609		-		37,609		-
Dispositions and farm-outs		(19,183)		-		(19,183)		-
Net capital expenditures		78,403		22,749		125,925		40,157
Ecuador		8,825		9,930		17,512		16,265
Adjusted net capital expenditures (1)	$	87,228	$	32,679	$	143,437	$	56,422
Net capital expenditures recorded as:								
Expenditures on exploration and evaluation assets	$	67,289	$	4,077	$	94,391	$	11,113
Expenditures on property, plant and equipment		30,297		18,672		50,717		29,044
Disposition and farm-outs		(19,183)		-		(19,183)		-
Net capital expenditures	$	78,403	$	22,749	$	125,925	$	40,157

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.

Capital expenditures in fiscal Q2 2015 primarily related to:

- Drilling, completion, facilities and seismic costs at LLA-23;
- Drilling, completion and facilities costs at Esperanza;
- Drilling and completion costs at VMM-2 (non-operated);
- Drilling, completion and facilities costs at Capella (non-operated);
- Acquisition costs at VIM-5, VIM-19, COR-4 and COR-12; and
- Drilling, completion and recompletion costs related to the Ecuador IPC (accounted for under the equity method of accounting)

LIQUIDITY AND CAPITAL RESOURCES

Capital Management

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

The Corporation monitors leverage and adjusts its capital structure based on the ratio of net debt to adjusted funds from operations. This ratio is calculated as net debt, defined as the principal amount of its outstanding bank debt plus the principal amount of its convertible debentures, unless the debentures are in-the-money or may otherwise be settled in common shares at the option of the Corporation, less working capital, as defined above and less the current portion of bank debt, convertible debentures and warrants included above, divided by adjusted funds from operations. The Corporation uses the ratio of net debt to adjusted funds from operations as a key indicator of the Corporation's leverage and to monitor the strength of its financial position.

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

Due to the weakness in crude oil prices over recent months and the resulting impact on cash flow, the Corporation's net debt leverage ratio has increased. As a result, the Corporation took immediate steps to reduce capital spending and preserve liquidity which, at December 31, 2014, had left the Corporation with $124.7 million in cash and cash equivalents and $74.8 million in restricted cash. Further, the Corporation has available an additional $50 million in committed debt facilities that it can draw down at any time up to April 2016 at the sole discretion of the Corporation, subject only to customary closing conditions. While crude oil prices are expected to remain weak for the remainder of 2015, the higher than normal leverage ratio is considered temporary since new gas deliveries for an additional 65 MMcfpd of firm contracted volumes at an average price of $6.60/MMbtu are expected to commence on December 1, 2015, thereby materially increasing revenues and funds from operations by the end of calendar 2015 and significantly reducing the net debt leverage ratio. In the meantime, the Corporation will maintain a prudent capital spending program and will focus on cost reductions to maximize profitability of the existing producing assets.

		December 31, 2014
Bank debt (current and long-term) – principal	$	255,333
Working capital surplus, excluding the current portion of bank debt and derivatives		(78,824)
Net debt	$	176,509
Annualized current quarter adjusted funds from operations [(1)]	$	91,808
Trailing 12 months adjusted funds from operations [(1)]	$	117,270
Net debt to current quarter annualized adjusted funds from operations		1.9
Net debt to trailing 12 months adjusted funds from operations		1.5

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above. Calculated as adjusted funds from operations for the three months ended December 31, 2014, annualized.

Credit Facilities and Debt

Senior Secured Term Loan

On April 3, 2013, the Corporation entered into a credit agreement for a $140 million senior secured term loan with a syndicate of banks. The Senior Secured Term Loan was for a five-year term, with interest payable quarterly and principal repayable in 15 equal quarterly instalments starting in October 2014, following an initial 18 month grace period. The Senior Secured Term Loan carried interest at LIBOR plus 4.50% and was secured by all of the material assets of the Corporation.

On April 24, 2014, the Corporation completed an upsizing of its existing Senior Secured Term Loan, from $140 million to $220 million, with no changes to the terms of the Senior Secured Term Loan or the repayment schedule. The revised term loan carries interest at LIBOR plus 4.50-5.00%, depending on agreed leverage ratios, and is secured by all of the material assets of the Corporation. The carrying value of the Senior Secured Term Loan included $7.1 million of transaction costs netted against the principal amount as at December 31, 2014.

The Senior Secured Term Loan includes various non-financial covenants relating to future acquisitions, indebtedness, operations, investments, capital expenditures and other standard operating business convents. The Senior Secured Term Loan also includes various financial covenants, including a maximum consolidated leverage ratio ("Consolidated Leverage Ratio"), a minimum consolidated interest coverage ratio ("Consolidated Interest Coverage Ratio"), a minimum debt service coverage ratio ("Debt Service Coverage Ratio"), a minimum consolidated current assets to consolidated current liabilities ratio ("Consolidated Current Assets to Consolidated Current Liabilities Ratio") and other standard financial covenants.

The Consolidated Leverage Ratio is calculated on a quarterly basis as consolidated total debt ("Consolidated Total Debt") divided by consolidated EBITDAX ("Consolidated EBITDAX"). The maximum allowable Consolidated Leverage Ratio is 2.75:1.00. Consolidated Total Debt includes the principal amount of all indebtedness, which currently includes bank debt, office lease commitments, and net hedging liabilities, if any, and specifically excludes amounts with respect to the Corporation's convertible debentures or warrants; additionally, restricted cash maintained in the debt service reserve account related to the Senior Secured Term Loan is deductible against Consolidated Total Debt. Consolidated EBITDAX is calculated on a rolling 12-month basis and is defined as consolidated net income adjusted for interest, income taxes, depreciation, depletion, amortization, exploration expenses, share of joint venture profit/loss and other similar non-recurring or non-cash charges. Consolidated EBITDAX is further adjusted for the contribution to adjusted funds from operations, before taxes, of the results of the Ecuador IPC as disclosed in the calculation of Adjusted Funds from Operations in the Corporation's management's discussion and analysis. The purpose of including this last amount is to capture the funds from operations of the Corporation's joint venture in Ecuador into the calculation as it is accounted for on an equity consolidation basis in the Corporation’s consolidated financial statements. Consolidated Total Debt and Consolidated EBITDAX are calculated as follows:

Consolidated Total Debt		**December 31, 2014**
Bank debt (current and long-term) – principal	$	255,333
Office lease commitments		5,701
Total		261,034
Debt service reserve account balance		(17,495)
Consolidated Total Debt	$	243,539

Consolidated EBITDAX	**Q3 F2014**	**Q4 F2014**	**Q1 F2015**	**Q2 F2015**	**Rolling**
Consolidated net income (loss)	19,438	(2,070)	14,110	(45,970)	(14,492)
(+) Interest expense	2,664	3,926	4,336	6,137	17,063
(+/-) Income taxes (recovery)	12,882	4,915	(1,190)	3,477	20,084
(+) Depletion and depreciation	9,015	14,897	19,493	16,818	60,223
(+) Exploration expenses	3,405	(2,482)	90	4,310	5,323
(-) Share of joint venture profit	(1,599)	(740)	(2,327)	(1,479)	(6,145)
(+/-) Other non-cash expenses (income) and non-recurring items	(11,921)	19,659	(358)	30,701	38,081
(+) Contribution of Ecuador IPC	6,784	7,231	8,439	7,474	29,928
Consolidated EBITDAX	40,668	45,336	42,593	21,468	150,065

Consolidated Leverage Ratio		**December 31, 2014**
Consolidated Total Debt	$	243,539
Consolidated EBITDAX		150,065
Consolidated Leverage Ratio		1.62

The Consolidated Interest Coverage Ratio is calculated on a quarterly basis as Consolidated EBITDAX divided by consolidated interest expense ("Consolidated Interest Expense"). The minimum Consolidated Interest Coverage Ratio required is 3.50:1.00. Consolidated EBITDAX is calculated on a rolling 12-month basis as described in the above paragraph. Consolidated Interest Expense is calculated on a rolling 12-month basis and includes interest expense, amortization of upfront fees, and capitalized interest.

Consolidated Interest Coverage Ratio		**December 31, 2014**
Interest expense and amortization of upfront fees	$	17,063
Capitalized interest		1,772
Consolidated Interest Expense	$	18,835
Consolidated EBITDAX	$	150,065
Consolidated Interest Coverage Ratio		7.97

The Debt Service Coverage Ratio is calculated on a quarterly basis as actual cash collections deposited by customers in the Corporation's collection accounts divided by the debt service amount ("Debt Service Amount"). The minimum Debt Service Coverage Ratio required is 1.50:1.00. The Debt Service Amount is defined as the sum of all amounts in respect of principal, interest, and fees payable on the interest payment date succeeding the date of the calculation. The Debt Service Coverage Ratio is calculated as follows:

Debt Service Coverage Ratio		December 31, 2014
Cash received in Collection Accounts – Q2 F2015	$	46,872
Debt Service Amount		17,204
Debt service Coverage Ratio		2.72

The Consolidated Current Assets to Consolidated Current Liabilities Ratio is calculated on a quarterly basis as consolidated current assets divided by consolidated current liabilities, excluding the current portion of any long-term indebtedness. The minimum Consolidated Current Assets to Consolidated Current Liabilities Ratio required is 1.00:1.00.

The Corporation was in compliance with its covenants as at December 31, 2014.

Senior Notes

On October 29, 2014, the Corporation entered into the $100 million unsecured floating rate senior note indenture agreement with Apollo Investment Corporation, with $50 million drawn and funded on October 29, 2014, and a further $50 million committed and available to be drawn at any time within 18 months at the sole discretion of the Corporation, subject only to customary closing conditions. The Senior Notes are repayable in full on their maturity date of December 31, 2019 and carry interest at LIBOR plus 8.5% per annum (subject to a LIBOR floor of 1.00%), payable quarterly. The Senior Notes may be repaid at any time prior to maturity and are subject to customary financial, performance and legal covenants which are consistent with the covenants under the Senior Secured Term Loan. Standby fees on the undrawn portion of the Senior Notes are calculated at 1% per annum.

Other Colombian Credit Facilities

The Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $33.5 million (COP$ 73.9 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. The facilities were undrawn as at December 31, 2014.

Letters of Credit

At December 31, 2014, the Corporation had letters of credit outstanding totaling $27 million to guarantee work commitments on exploration blocks and to guarantee other contractual commitments. The total of these letters of credit, net of amounts counter-guaranteed by other financial institutions, reduce the amounts available under the Colombian revolving lines of credit by $10 million.

Convertible Debentures

The Corporation has convertible debentures outstanding with a face value of $22 million (fair value – $21.9 million) that mature on June 30, 2015, and bear an annual coupon rate of 8%, payable semi-annually. The debentures are convertible into common shares of the Corporation at the option of the holder at a conversion price of C$10.526 per share, being the ratio of 95 common shares per C$1,000 principal amount of the debentures. On the maturity date, the Corporation has a right to repay the outstanding principal amount and any accrued interest in common shares of the Corporation, subject to certain conditions, including customary regulatory approvals.

Share Capital

At February 10, 2015, the Corporation had 107.8 million common shares, 2.4 million warrants, 10.5 million stock options, and 0.3 million cash-settled restricted share units outstanding.

Contractual Obligations

The following table provides a summary of the Corporation's cash requirements to meet its financial liabilities and contractual obligations existing at December 31, 2014:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	$ 58,667	$ 146,666	$ 50,000	$ 255,333
Trade and other payables	83,682	-	-	83,682
Crude oil payable in kind	1,616	-	-	1,616
Taxes payable	15,332	-	-	15,332
Deferred income	-	3,731	-	3,731
Other long term obligations	-	-	219	219
Convertible debentures – principal	21,997	-	-	21,997
Warrants	130	56	-	186
Restricted share units	317	300	-	617
Exploration and production contracts	16,553	48,183	-	64,736
Office leases	943	1,617	3,141	5,701

Exploration and Production Contracts

The Corporation has entered into a number of exploration contracts in Colombia and Peru which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at December 31, 2014 of $64.7 million and has issued $25.7 million in financial guarantees related thereto. These commitments are planned to be satisfied by means of seismic work, exploration drilling and farm-outs.

Oleoducto Bicentenario de Colombia ("OBC") Pipeline

The Corporation owns a 0.5% interest in OBC, which owns a pipeline system that will link Llanos basin oil production to the Cano Limon oil pipeline system. Under the terms of the OBC agreement, the Corporation may be required to provide financial support or guarantees for its proportionate equity interest in any future debt financings undertaken by OBC. The Corporation has also entered into ship-or-pay arrangements with OBC to guarantee pipeline revenues.

Ecuador Incremental Production Contract

In addition to the contractual obligations described above, the Corporation has a non-operated 25% equity participation interest (27.9% capital participation interest) in a joint-venture consortium which in 2012 was awarded an incremental production contract for the Libertador and Atacapi mature oil fields in Ecuador. The consortium plans to incur project expenditures estimated for a total of $397 million ($107.6 million net to the Corporation) over the 15 year term of the contract. As at December 31, 2014, the Corporation had incurred $73.1 million of expenditures in connection with its Ecuador IPC commitment.

OUTLOOK

In light of continued weakness in benchmark crude oil prices, the Corporation will focus its efforts in calendar 2015 on: 1) development activity and infrastructure spending at its Esperanza and VIM-5 gas contracts to bring total production up to 83 MMcfpd (14,561 boepd) from the current 20 MMcfpd (3,509 boepd) by calendar year end 2015; 2) negotiation of additional gas contracts related to the Clarinete gas discovery and initiation of field development to commercialize the discovery; 3) infrastructure spending and seismic acquisition on the LLA-23 light oil contract with a focus on continued cost reductions and firming up future exploration leads; and 4) tariff oil production operations in Ecuador, which are insensitive to crude oil prices.

Two production tests at Clarinete-1 were completed and announced in January and February 2015. The lower part of the Cienaga de Oro sandstone reservoir was perforated in various intervals between 6,919 and 7,230 feet measured depth. This interval flowed naturally at a stable gross rate of 20.6 MMcfpd (3,606 boepd) using a 36/64 inch choke with a tubing head pressure of 2,528 pounds per square inch with no water, at the end of a 72 hour flow period. The upper part of the Cienaga de Oro sandstone reservoir was perforated in various intervals between 6,409 and 6,568 feet measured depth. This interval achieved a final rate of 24.7 MMcfpd (4,333 boepd) using a 42/64 inch choke with a tubing head pressure of 2,274 pounds per square inch with no water, at the end of a 16 hour flow period. The combined gross deliverability of the Clarinete-1 well from both intervals is approximately 45.3 MMcfpd (7,947 boepd). Meanwhile the Corporation is preparing to lay a flowline to tie the Clarinete-1 well into its operated gas processing facility at the Jobo station. The Corporation has identified ten prospects and leads within the recently acquired VIM-5 and VIM-19 that contain a significant volume of prospective resource assuming all prospects are drilled according to a July 2014 NI 51-101 compliant report from Gaffney Cline and Associates ("GCA"). The gross unrisked pre drill best estimate for the Clarinete prospect as per the GCA prospective resource report is 540 bcf of gas. Pursuant to an existing agreement, and subject to approval from the ANH, an industry joint venture partner has the ability to earn up to 25% of the Corporation's 100% interest in exchange for fulfilling certain financial commitments. The Corporation plans to negotiate additional new gas sales contracts associated with the Clarinete discovery, and has already executed one new contract described below.

In February 2015, the Corporation executed a new 15 year take or pay contract for the sale of 35 MMcfpd (6,140 boepd) of gas to Altenesol commencing in the third quarter of calendar 2016. Under the terms of the contract, Altenesol will pay \$4.90/MMbtu (\$27.93/boe), escalated at 2% per year across the term of the contract. In addition, Canacol and Altenesol executed an agreement pursuant to which Canacol has the option, valid for six months from the agreement date, to participate in the revenues generated by the sale of the LNG through an equity ownership position in Altenesol of approximately 26% in exchange for investing \$13 million in the project. Altenesol will use the gas to produce approximately 360,000 gallons of LNG per day at a dedicated liquefaction facility to be located close to Canacol's operated Jobo gas processing facility. Altenesol has recently executed a 15 year take or pay contract to sell the LNG to be produced by the facility to a large international distributor for export to markets in the Caribbean at a sales price of approximately \$11/MMbtu (\$62.70/boe) at the sales point of Cartagena in Colombia. Canacol, through its beneficial ownership of Altenesol, will also derive revenues from the sale of the LNG of approximately \$1.25/MMbtu (\$7.12/boe). As such, total revenues from the gas sales contract and Canacol's beneficial ownership in Altenesol are expected to be approximately \$6.25/MMbtu (\$35.63/boe) escalated at 2% per year across the 15 year tenure of the take or pay contract. The gas for the contract is expected to come from the recently discovered Clarinete gas field described above.

On the Esperanza contract, the Corporation plans to test the Corozo-1 well, subject to ANH approval, using the same rig from Clarinete-1 once operations there are completed. Based upon the significant gas resource potential of the Clarinete discovery, the Corporation decided to defer the drilling of the Canandonga-1 exploration well on the Esperanza contract, and instead drilled the Nelson-5 development well at its operated Nelson gas field, which is currently being tied in. Otherwise, the Corporation is in the process of various infrastructure spending at Esperanza to install flow lines and expand the Jobo station in order to deliver the 83 MMcfpd of contracted gas by the end of calendar 2015. The Corporation has already executed three new gas sales contracts for a combined 65 MMcfpd which is expected to take Canacol's current daily gas production of approximately 20 MMcfpd (3,509 boepd) to 83 MMcfpd (14,561 boepd) in late calendar 2015. The new contracts each have a five year term, with pricing of \$ 5.40/MMbtu escalated at 2% per year for two of the contracts totalling 35 MMcfpd, and \$8.00/MMbtu escalated at approximately 3% per year for the third contract of 30 MMcfpd. Canacol currently sells approximately 18 MMcfpd (3,158 boepd) of gas from the Nelson Field to a local ferronickel producer under a 10 year contract that expires in 2021. That contract was linked to the Guajira price index, which changed effective October 29, 2014 from \$3.97/MMbtu (\$22.63/boe) to

$5.08/MMbtu ($28.96/boe). Nevertheless, as mentioned above, the Corporation has diversified its future gas sales with the addition of three new fixed-price gas contracts commencing in December 2015.

Despite low crude oil prices, production from the LLA-23 block remains profitable due to the high deliverability of the reservoirs and the effective cost structure. The Corporation will continue with spending on facilities upgrades and water injection that commenced in 2014 and expects to realize lower operating costs by mid-2015. The Corporation is also in the process of acquiring 400 square kilometer 3D seismic on the block with the objective of firming up the portfolio of 12 currently identified exploration leads into prospects for drilling in calendar 2015 and 2016. No immediate exploration drilling on the LLA-23 block is planned at the present time.

In Ecuador, the consortium plans to drill one new development well and work over four existing producing wells. Further, the consortium plans to complete five waterflood pilots and spend capital on waterflood facilities and other infrastructure.

In other areas of Colombia, the Corporation and its partner expect to drill up to two additional appraisal wells into the shallow Lisama discovery on the VMM-2 block in calendar 2015. The operator of the Capella property is expected to continue its development program for the field through calendar 2015. The operator of the VMM-3 block drilled the Pico Plata-1 exploration well in early October 2014 targeting the shale of the Cretaceous La Luna formation and is currently coring the well. No material calendar 2015 capital expenditures are planned on any of the Corporation's other oil properties at the present time.

SUMMARY OF QUARTERLY RESULTS

	2015		2014				2013	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial								
Petroleum and natural gas revenues, net of royalties	**36,404**	58,917	61,744	55,653	42,168	48,222	38,961	34,602
Adjusted petroleum and natural gas revenues, net of royalties, including revenues relate to the Ecuador IPC (1)	**43,878**	66,978	68,975	62,437	47,101	52,391	42,430	36,725
Cash provided by operating activities	**31,743**	45,618	8,715	13,099	36,406	19,724	13,829	(8,520)
Per share – basic	**0.29**	0.42	0.09	0.15	0.42	0.23	0.16	(0.10)
Per share – diluted	**0.29**	0.42	0.09	0.15	0.41	0.23	0.16	(0.10)
Adjusted funds from operations (1)	**22,952**	37,162	23,995	33,161	16,713	25,047	19,737	15,578
Per share – basic (1)	**0.21**	0.34	0.25	0.37	0.19	0.29	0.23	0.18
Per share – diluted (1)	**0.21**	0.34	0.24	0.36	0.19	0.29	0.23	0.18
Net income (loss)	**(45,970)**	14,110	(2,070)	19,438	(10,412)	2,981	(119,046)	(3,425)
Per share – basic	**(0.43)**	0.13	(0.02)	0.22	(0.12)	0.03	(1.38)	(0.04)
Per share – diluted	**(0.43)**	0.13	(0.02)	0.21	(0.12)	0.03	(1.38)	(0.04)
Capital expenditures, net	**78,403**	47,522	77,093	35,915	22,749	17,408	13,099	3,021
Adjusted capital expenditures, net, including capital expenditures related to the Ecuador IPC (1)	**87,228**	56,209	87,584	44,103	32,679	23,743	15,758	10,434
Operations (boepd)								
Petroleum and natural gas **production**, before royalties								
Petroleum (2)	**8,586**	9,922	9,271	8,260	6,998	6,110	5,390	4,785
Natural gas	**3,236**	3,334	2,941	2,633	3,097	3,022	2,879	2,874
Total (2)	**11,822**	13,256	12,212	10,893	10,095	9,132	8,269	7,659
Petroleum and natural gas **sales**, before royalties								
Petroleum (2)	**8,187**	9,997	9,386	8,792	5,868	6,307	5,372	4,267
Natural gas	**3,216**	3,311	2,937	2,626	2,953	3,052	2,914	2,874
Total (2)	**11,403**	13,308	12,323	11,418	8,821	9,359	8,286	7,141

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Includes tariff oil production related to the Ecuador IPC.

RISKS AND UNCERTAINTIES

There have been no significant changes in the three and six months ended December 31, 2014 to the risks and uncertainties as identified in the MD&A for the year ended June 30, 2014.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgements, assumptions and estimates in the preparation of the financial statements. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and the Corporation's significant accounting policies can be found in the notes to the financial statements.

CHANGES IN ACCOUNTING POLICIES

The Corporation is currently reviewing a number of new and revised IFRSs that have been issued but are not yet effective. Detailed discussions of new accounting policies that may affect the Corporation are provided in the unaudited interim condensed consolidated financial statements of the Corporation as at and for the three and six months ended December 31, 2014 and the audited consolidated financial statements as at and for the year ended June 30, 2014.

REGULATORY POLICIES

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("DC&P") are designed to provide reasonable assurance that all relevant information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure. The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), along with other members of management, have designed, or caused to be designed, under the CEO and CFO's supervision, disclosure controls and procedures and established processes to ensure that they are provided with sufficient knowledge to support the representations made in the interim certificates required to be filed under National Instrument 52-109.

Internal Controls over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate Internal Control over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial statements prepared in accordance with IFRS.

During the quarter ended December 31, 2014, there has been no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Limitations of Controls and Procedures

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