CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
SIX MONTHS ENDED DECEMBER 31, 2015

FINANCIAL & OPERATING HIGHLIGHTS

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

Financial	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Petroleum and natural gas revenues, net of royalties	**16,472**	36,404	(55%)	**38,430**	149,047	(74%)
Adjusted petroleum and natural gas revenues, net of royalties (2)	**23,953**	43,878	(45%)	**53,852**	177,937	(70%)
Cash provided by operating activities	**4,974**	31,743	(84%)	**19,276**	64,445	(70%)
Per share – basic ($)	**0.03**	0.29	(90%)	**0.14**	0.58	(76%)
Per share – diluted ($)	**0.03**	0.29	(90%)	**0.13**	0.58	(78%)
Adjusted funds from operations (1) (2)	**8,473**	22,952	(62%)	**23,690**	87,395	(73%)
Per share – basic ($)	**0.05**	0.21	(76%)	**0.17**	0.79	(78%)
Per share –diluted ($)	**0.05**	0.21	(76%)	**0.16**	0.78	(79%)
Comprehensive loss	**(84,466)**	(45,970)	84%	**(103,495)**	(106,022)	(2%)
Per share – basic ($)	**(0.54)**	(0.43)	26%	**(0.72)**	(0.96)	(25%)
Per share – diluted ($)	**(0.54)**	(0.43)	26%	**(0.72)**	(0.96)	(25%)
Capital expenditures, net, including acquisitions	**22,394**	78,403	(71%)	**44,693**	217,342	(79%)
Adjusted capital expenditures, net, including acquisitions (1)(2)	**22,867**	87,228	(74%)	**48,947**	243,108	(80%)
				December 31, 2015	June 30, 2015	Change
Cash				**43,257**	45,765	(5%)
Restricted cash				**61,721**	61,772	-
Working capital surplus, excluding non-cash items (1)				**46,310**	62,883	(26%)
Long-term bank debt				**248,228**	267,023	(7%)
Total assets				**668,349**	669,742	-
Common shares, end of period (000s)				**159,266**	126,434	26%

Operating	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Petroleum and natural gas **production**, before royalties (boepd)						
Petroleum (3)	**5,523**	8,586	(36%)	**6,253**	7,999	(22%)
Natural gas	**3,541**	3,236	9%	**3,507**	3,505	-
Total (2)	**9,064**	11,822	(23%)	**9,760**	11,504	(15%)
Petroleum and natural gas **sales**, before royalties (boepd)						
Petroleum (3)	**5,468**	8,187	(33%)	**6,370**	8,010	(20%)
Natural gas	**3,542**	3,216	10%	**3,499**	3,512	-
Total (2)	**9,010**	11,403	(21%)	**9,869**	11,522	(14%)
Realized sales prices ($/boe)						
LLA-23 (oil)	**28.56**	58.62	(51%)	**31.89**	59.91	(47%)
Esperanza (natural gas)	**28.77**	25.12	15%	**27.67**	25.04	11%
Clarinete (natural gas)	**31.37**	-	n/a	**31.37**	-	n/a
Ecuador (tariff oil) (2)	**38.54**	38.54	-	**38.54**	38.54	-
Total (2)	**31.20**	45.55	(32%)	**32.18**	45.76	(30%)
Operating netbacks ($/boe) (1)						
LLA-23 (oil)	**12.02**	30.78	(61%)	**16.74**	34.91	(52%)
Esperanza (natural gas)	**24.03**	20.04	20%	**23.27**	20.62	13%
Clarinete (natural gas)	**20.78**	-	n/a	**20.78**	-	n/a
Ecuador (tariff oil) (2)	**38.54**	38.54	-	**38.54**	38.54	-
Total (2)	**21.96**	25.14	(13%)	**22.38**	28.05	(20%)

(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. 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 March 22, 2016 and is the Corporation's explanation of its financial performance for the year covered by its financial statements along with an analysis of the Corporation's financial position. Comments relate to and should be read in conjunction with the audited consolidated financial statements of the Corporation for the six months ended December 31, 2015 and twelve months ended June 30, 2015 (the "financial statements"). The financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS"), 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. The financial year end of the Corporation was changed from June 30 to December 31. Accordingly, the fiscal year-to-date comparative figures for the following MD&A are for the twelve month period ended June 30, 2015.

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, that the Ecuadorian government will not renegotiate tariff prices on certain fixed priced contracts during low oil price environment, 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, 2015	Three months ended December 31, 2014	**Six months ended December 31, 2015**	Twelve months Ended June 30, 2015
Cash provided by operating activities	**$ 4,974**	$ 31,743	**$ 19,276**	$ 64,445
Changes in non-cash working capital	**(3,982)**	(15,712)	**(11,007)**	(4,742)
Ecuador IPC revenue, net of current income tax	**7,481**	6,921	**15,421**	27,692
Adjusted funds from operations	**$ 8,473**	$ 22,952	**$ 23,690**	$ 87,395

In addition to the above, management uses working capital and operating netback measures. Working capital is calculated as current assets less current liabilities, excluding any non-cash items, 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, 2015, the Corporation's production primarily consisted of natural gas from from its Nelson, Palmer and Clarinete fields in the Lower Magdalena Basin in Colombia, crude oil from its Leono, Labrador, Pantro, Tigro and Maltes fields in the Llanos Basin in Colombia, tariff oil from the Ecuador IPC, and, to a lesser extent, crude oil from its Rancho Hermoso, VMM-2 and Santa Isabel properties in Colombia.

Producing Properties

The Nelson and Palmer fields at the Esperanza block and the Clarinete field at the VIM-5 block, located in the Lower Magdalena Basin in Colombia, produce dry natural gas for sale to local customers under long-term contracts. On July 13, 2015, the Corporation announced that the Autoridad Nacional de Licencias Ambientales has approved the environmental permit enabling Promigas S.A. E.S.P. ("Promigas") to commence construction necessary to increase capacity of the existing Jobo to Cartagena natural gas pipeline. This expansion allows Canacol to increase net gas production by an additional 65 million standard cubic feet per day ("MMscfpd") (11,400 boe per day ("boepd")). The pipeline is currently anticipated to be completed by March 31, 2016. Upon completion of this pipeline expansion, the Corporation's net natural gas shipping capacity will increase to approximately 90 MMscfpd (15,789 boepd). During the majority of 2015, Canacol sold approximately 18 MMscfpd (3,158 boepd) of gas from the Nelson Field to a local ferronickel producer under a 10 year contract that expires in 2021. The existing Nelson, Palmer and Clarinete fields are expected to have sufficient productive capacity to deliver the contracted gas by March 31, 2016.

On January 19, 2016, the Corporation spud the Oboe-1 gas exploration well on the VIM-5 block. The Oboe-1 well reached a total depth of 9,750 feet measured depth ("ft md") on February 7, 2016, which encountered 158 feet of net gas pay with average porosity of 23% within multiple stacked sandstone reservoirs in the primary Cienaga de Oro target, representing the thickest gas pay encountered in the Cienaga de Oro in the Clarinete discovery thus far. Three separate reservoir intervals have been successfully tested during February and March 2016: the first interval between 8,116 and 8,683 ft md flowed 26 MMscfpd (4,561 boepd) of dry gas, the second interval between 7,309 and 8,106 ft md flowed 27 MMscfpd (4,737 boepd) of dry gas, and the third interval between 6,556 and 7,270 ft md flowed 13 MMscfpd (2,281 boepd) of dry gas.

The Corporation, through a consortium, participates in an incremental production contract for the Libertador and Atacapi fields in Ecuador whereby the Corporation is entitled to 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. 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.

Both gas sales from Esperanza and Clarinete and tariff oil from Ecuador ($38.54/bbl), together comprising approximately 62% of production in the three months ended December 31, 2015, are insensitive to world oil prices, offering the Corporation a significant degree of protection from the effects of low benchmark oil prices. Despite the further drop in crude oil average realized prices during the three months ended December 31, 2015, the Corporation's primary oil producing fields located on the LLA-23 block achieved over $12/bbl operating netbacks as a result of cost-cutting initiatives such as centralizing the production, loading, and water disposal operations from the different fields within the LLA-23 block to the Pointer platform, thereby reducing operating expenses, transportation expenses and water handling costs via reinjection.

For the three months ended December 31, 2015, the Corporation also had other crude oil production from its Rancho Hermoso, 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. The Corporation's Rancho Hermoso, VMM-2 and Santa Isabel properties individually contributed only a minor amount to total production in the three months ended December 31, 2015 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. As of the date of this MD&A, all wells at the Capella and VMM-2 fields have been shut-in.

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

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, 2015	Three months ended December 31, 2014	Change	**Six months ended December 31, 2015**	Twelve months ended June 30, 2015	Change
Production (boepd)						
LLA-23 (oil)	**2,745**	4,953	(45%)	**3,429**	4,657	(26%)
Esperanza (gas)	**3,350**	3,236	4%	**3,411**	3,505	(3%)
Clarinete (gas)	**191**	-	n/a	**96**	-	n/a
Ecuador (tariff oil)	**2,078**	1,967	6%	**2,117**	1,927	10%
Rancho Hermoso and other (oil)	**700**	1,666	(58%)	**707**	1,415	(50%)
Total production	**9,064**	11,822	(23%)	**9,760**	11,504	(15%)
Inventory movements and other	**(54)**	(419)	(87%)	**109**	18	522%
Total sales	**9,010**	11,403	(21%)	**9,869**	11,522	(14%)
Sales (boepd)						
LLA-23 (oil)	**2,745**	4,744	(42%)	**3,523**	4,668	(25%)
Esperanza (gas)	**3,349**	3,216	4%	**3,402**	3,512	(3%)
Clarinete (gas)	**193**	-	n/a	**97**	-	n/a
Ecuador (tariff oil)	**2,078**	1,967	6%	**2,117**	1,927	10%
Rancho Hermoso and other (oil)	**645**	1,476	(56%)	**730**	1,415	(48%)
Total sales	**9,010**	11,403	(21%)	**9,869**	11,522	(14%)

The overall decrease in production volumes in the three months ended December 31, 2015 compared to the same period in 2014 is primarily due to production declines from LLA-23 and Rancho Hermoso and other, as well as decreased gas production due to pipeline capacity being down for further construction, offset by increases in tariff oil production from Ecuador. The overall decrease in production volumes in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 is primarily due to production declines from LLA-23 and Rancho Hermoso and other, as well as decreased gas production due to pipeline capacity being down for further construction, offset by increases in tariff oil production. LLA-23 oil production decreased in the three months ended December 31, 2015 compared to the three months ended September 30, 2015 as the prior quarter included flush production associated with the workovers performed during the quarter.

Petroleum and Natural Gas Revenues

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	**Six months ended December 31, 2015**	Twelve months ended June 30, 2015	Change
LLA-23	**$ 7,213**	$ 25,584	(72%)	**$ 20,672**	$ 102,076	(80%)
Esperanza	**8,864**	7,431	19%	**17,323**	32,093	(46%)
Clarinete	**557**	-	n/a	**557**	-	n/a
Rancho Hermoso and other	**1,858**	7,794	(76%)	**4,867**	31,144	(84%)
Petroleum and natural gas revenues, before royalties	**18,492**	40,809	(55%)	**43,419**	165,313	(74%)
Royalties	**(2,020)**	(4,405)	(54%)	**(4,989)**	(16,266)	(69%)
Petroleum and natural gas revenues, after royalties, as reported	**16,472**	36,404	(55%)	**38,430**	149,047	(74%)
Ecuador tariff and other revenues	**7,481**	7,474	-	**15,422**	28,890	(47%)
Adjusted petroleum and natural gas revenues, after royalties [(1)]	**$ 23,953**	$ 43,878	(45%)	**$ 53,852**	$ 177,937	(70%)

(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, 2015 compared to the same period in 2014 is primarily the result of the decreased overall sales of 21% by volume and the impact of lower realized average prices during the quarter as a result of declines in benchmark crude oil prices. The decrease in adjusted petroleum and natural gas revenues in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 is primarily the result of the fact that a comparison is being made between a six month period versus a twelve month period, as well as the impact of lower realized average prices during the period.

Average Benchmark and Realized Sales Prices

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	**Six months ended December 31, 2015**	Twelve months ended June 30, 2015	Change
Brent ($/bbl)	**$ 43.56**	$ 76.43	(43%)	**$ 47.00**	$ 73.51	(36%)
West Texas Intermediate ($/bbl)	**$ 41.94**	$ 73.21	(43%)	**$ 44.31**	$ 69.46	(36%)
LLA-23 ($/bbl)	**$ 28.56**	$ 58.62	(51%)	**$ 31.89**	$ 59.91	(47%)
Esperanza ($/boe)	**28.77**	25.12	15%	**27.67**	25.04	11%
Clarinete ($/boe)	**31.37**	-	n/a	**31.37**	-	n/a
Ecuador ($/bbl)	**38.54**	38.54	-	**38.54**	38.54	-
Rancho Hermoso and other ($/bbl)	**31.31**	57.40	(45%)	**36.23**	60.31	(40%)
Average realized sales price ($/boe) [(1)]	**$ 31.20**	$ 45.55	(32%)	**$ 32.18**	$ 45.76	(30%)

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

The decrease in average realized crude oil sales prices in the three months ended December 31, 2015 compared to the same period in 2014 is mainly due to decreased benchmark crude oil prices. The decrease in average realized crude oil sales prices in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 is mainly due to decreased benchmark crude oil prices and increased delivery of crude oil at the well head, thereby reducing average realized crude oil sales prices as well as transportation expenses.

The increase in average realized natural gas sales prices in the three months ended December 31, 2015 compared to the same period in 2014 and the increase in average realized natural gas sales prices in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 are due to a) the increase in the Guajira price in October 2014, from $3.97/MMbtu to $5.08/MMbtu, and further increased to $6.17/MMbtu in December 2015, and b) the Corporation's intermittent sales of natural gas on the spot market at prices higher than the Guajira price.

The Corporation estimates that total gas sales from Esperanza and VIM-5 (Clarinete and Oboe fields) will average approximately 80 MMscfpd (14,035 boepd) for calendar 2016 (including approximately 90 MMscfpd for the last three quarters of calendar 2016) at an anticipated average realized price of $5.60/Mcf ($31.92/boe), which is expected to generate approximately $163 million of revenues before royalties.

The tariff price for Ecuador tariff oil production is fixed at $38.54/bbl.

Royalties

	Three months ended December 31, 2015	Three months ended December 31, 2014	**Six months ended December 31, 2015**	Twelve months Ended June 30, 2015
LLA-23	**$ 989**	$ 3,117	**$ 3,057**	$ 11,018
Esperanza	**736**	605	**1,382**	2,669
Clarinete	**119**	-	**119**	-
Rancho Hermoso and other	**176**	683	**431**	2,579
Total royalties	**$ 2,020**	$ 4,405	**$ 4,989**	$ 16,266

In Colombia, light crude oil and natural gas royalties are generally at a rate of 8% and 6.4%, respectively, until net field production reaches 5,000 boepd, at which time they increase on a sliding scale to 20% up to field production of 125,000 boepd. 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. Crude oil royalties in Labrador, Rancho Hermoso and Capella are taken in kind. There are no royalties on tariff production in Ecuador. The Corporation's Esperanza natural gas production is subject to an additional overriding royalty of 2% and the

Corporation's Clarinete natural gas production is subject to an additional x-factor royalty of 13% and an overriding royalty of 3%.

Production and Transportation Expenses

Total production and transportation expenses were as follows:

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Production expenses	$ 4,906	$ 15,342	(68%)	$ 11,323	$ 51,253	(78%)
Transportation expenses	727	1,667	(56%)	1,473	6,961	(79%)
Total production and transportation expenses	$ 5,633	$ 17,009	(67%)	$ 12,796	$ 58,214	(78%)
$/boe	$ 6.80	$ 16.21	(58%)	$ 7.05	$ 13.84	(49%)

An analysis of production expenses is provided below:

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
LLA-23	$ 2,688	$ 8,365	(68%)	$ 5,663	$ 27,094	(79%)
Esperanza	725	900	(19%)	1,372	3,004	(54%)
Clarinete	69	-	n/a	69	-	n/a
Rancho Hermoso and other	1,424	6,077	(77%)	4,219	21,155	(80%)
Total production expenses	$ 4,906	$ 15,342	(68%)	$ 11,323	$ 51,253	(78%)
$/boe						
LLA-23	$ 10.64	$ 19.17	(44%)	$ 8.74	$ 15.90	(45%)
Esperanza	$ 2.35	$ 3.04	(23%)	$ 2.19	$ 2.34	(7%)
Clarinete	$ 3.89	$ -	n/a	$ 3.89	$ -	n/a
Total	$ 5.92	$ 14.62	(60%)	$ 6.24	$ 12.19	(49%)

Production expenses at LLA-23 decreased 68% in the three months ended December 31, 2015 compared to the same period in 2014. The decrease is primarily due to lower production, lower renegotiated operating costs, centralization of the production, loading and water disposal operations from different fields within the LLA-23 block to the Pointer platform, and devaluation of the Colombian peso versus the United States dollar. Production expenses at LLA-23 decreased 79% in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015. The decrease is primarily due to the fact that a comparison is being made between a six month period versus a twelve month period but also due to lower production, lower renegotiated operating costs, centralization of the production, loading and water disposal operations from different fields within the LLA-23 block to the Pointer platform, and the devaluation of the Colombian peso versus the United States dollar.

Production expenses at Esperanza decreased 19% in the three months ended December 31, 2015 compared to the same period in 2014. The decrease is primarily due to the devaluation of the Colombian peso versus the United States dollar, offset by increased production. Production expenses at Esperanza decreased 54% in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015. The decrease is primarily due to the fact that a comparison is being made between a six month period versus a twelve month period but also due to lower production and the devaluation of the Colombian peso versus the United States dollar.

Production expenses at Rancho Hermoso and other decreased 77% in the three months ended December 31, 2015 compared to the same period in 2014. The decrease is primarily the result of lower production, Ecopetrol's reimbursement of a portion of the production expenses in Rancho Hermoso, lower renegotiated operating costs and the devaluation of the Colombian peso versus the United States dollar. Production expenses at Rancho Hermoso and other decreased 80% in the six months ended December 31, 2015 compared to twelve months ended June 30, 2015. The decrease is primarily the result of the fact that a comparison is being made between a six month period versus a twelve month period but also due to lower production, Ecopetrol's reimbursement of a portion of the production expenses in Rancho Hermoso, lower renegotiated operating costs and the devaluation of the Colombian peso versus the United States dollar. Under its contract with Ecopetrol, the Corporation has paid 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. On October 30, 2015, Ecopetrol has agreed to reimburse 40% of the gross production expenses at a fixed $15 per gross barrel of oil production, thereby reducing the Corporation's production expenses at Rancho Hermoso. However, production expenses for Rancho Hermoso oil remain higher than a similar operation that is subject to an ANH contract, such as LLA-23, Capella, VMM-2 and Santa Isabel, due to the reimbursement cap.

In light of continued weakness in benchmark crude oil prices, the Corporation continues to focus its efforts on reducing 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 has centralized its production, loading, and water disposal operations from the different fields within the LLA-23 block to the Pointer platform; in so doing reducing operating expenses, transportation expenses and water handling costs via reinjection. In Rancho Hermoso, the Corporation has 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. As of the date of this MD&A, all wells at the Capella and VMM-2 fields have been shut-in.

The Corporation does not pay production expenses in Ecuador, and as such, its tariff price of $38.54 equals netback.

An analysis of transportation expenses is provided below:

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	**Six months ended December 31, 2015**	Twelve months ended June 30, 2015	Change
LLA-23	**$ 499**	$ 666	(25%)	**$ 1,098**	$ 4,480	(75%)
Rancho Hermoso and other	**228**	1,001	(77%)	**375**	2,481	(85%)
Total transportation expenses	**$ 727**	$ 1,667	(56%)	**$ 1,473**	$ 6,961	(79%)
$/boe						
LLA-23	**$ 1.98**	$ 1.53	29%	**$ 1.69**	$ 2.63	(36%)
Total	**$ 0.88**	$ 1.59	(45%)	**$ 0.81**	$ 1.66	(51%)

Total transportation expenses have decreased by 56% in the three months ended December 31, 2015 compared to the same period in 2014 mainly due to lower transportation rates, decreased sales volumes and the devaluation of the Colombian peso versus the United States dollar. Total transportation expenses have decreased by 79% in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 mainly due to the fact that a comparison is being made between a six month period versus a twelve month period as well as lower transportation rates, increased delivery of crude oil at the well head, decreased sales volumes and the devaluation of the Colombian peso versus the United States dollar.

The Corporation does not pay transportation costs at Esperanza or Clarinete as gas pipeline costs are paid by the offtakers. The Corporation does not pay transportation costs in Ecuador.

Operating Netbacks

$/boe	**Three months ended December 31, 2015**	Three months ended December 31, 2014	Change	**Six months ended December 31, 2015**	Twelve months ended June 30, 2015	Change
Petroleum and natural gas revenues	**$ 31.20**	$ 45.55	(32%)	**$ 32.18**	$ 45.76	(30%)
Royalties	**(2.44)**	(4.20)	(42%)	**(2.75)**	(3.87)	(29%)
Production and transportation expenses	**(6.80)**	(16.21)	(58%)	**(7.05)**	(13.84)	(49%)
Operating netback (1)	**$ 21.96**	$ 25.14	(13%)	**$ 22.38**	$ 28.05	(20%)

(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, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
LLA-23						
Crude oil revenues	$ 28.56	$ 58.62	(51%)	$ 31.89	$ 59.91	(47%)
Royalties	(3.92)	(7.14)	(45%)	(4.72)	(6.47)	(27%)
Production and transportation expenses	(12.62)	(20.70)	(39%)	(10.43)	(18.53)	(44%)
Operating netback	$ 12.02	$ 30.78	(61%)	$ 16.74	$ 34.91	(52%)
Esperanza						
Natural gas revenues	$ 28.77	$ 25.12	15%	$ 27.67	$ 25.04	11%
Royalties	(2.39)	(2.04)	17%	(2.21)	(2.08)	6%
Production expenses	(2.35)	(3.04)	(23%)	(2.19)	(2.34)	(7%)
Operating netback	$ 24.03	$ 20.04	20%	$ 23.27	$ 20.62	13%
Clarinete						
Natural gas revenues	$ 31.37	$ -	n/a	$ 31.37	$ -	n/a
Royalties	(6.70)	-	n/a	(6.70)	-	n/a
Production expenses	(3.89)	-	n/a	(3.89)	-	n/a
Operating netback	$ 20.78	$ -	n/a	$ 20.78	$ -	n/a
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, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Gross costs	$ 9,570	$ 8,440	13%	$ 15,240	$ 28,259	(46%)
Less: capitalized amounts	(945)	(684)	38%	(1,765)	(4,209)	(58%)
General and administrative expenses	$ 8,625	$ 7,756	11%	$ 13,475	$ 24,050	(44%)
$/boe	$ 10.41	$ 7.39	41%	$ 7.42	$ 5.72	30%

Gross general and administrative expenses ("G&A") increased by 13% in the three months ended December 31, 2015 compared to same period in 2014 primarily due to the payment of severance which amounted to $1.7 million. Gross G&A expenses increased by 46% in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 due to the fact that a comparison is being made between a six month period versus a twelve month period in addition to the $1.7 million severance paid during the three months ended December 31, 2015. Extensive reviews have been undertaken with a focus on significant G&A reduction in 2016.

Net Finance Income and Expense

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Net financing paid	$ 4,162	$ 4,007	4%	$ 9,260	$ 16,761	(45%)
Non-cash financing costs	1,108	1,475	(25%)	2,193	11,046	(80%)
Net finance expense	**$ 5,270**	$ 5,482	(4%)	**$ 11,453**	$ 27,807	(59%)

Commodity Contracts

The Corporation had no commodity contracts outstanding as at and for the six months ended December 31, 2015.

Stock-Based Compensation Expense

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Gross costs	$ 2,814	$ 2,523	12%	$ 4,803	$ 8,353	(43%)
Less: capitalized amounts	(547)	(466)	17%	(930)	(2,466)	(62%)
Stock-based compensation expense	**$ 2,267**	$ 2,057	10%	**$ 3,873**	$ 5,887	(34%)

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.

Restricted Share Units

	Number (000s)	Amount
Balance at June 30, 2015	158	$ 350
Granted	45	94
Settled	(125)	(273)
Realized loss	-	24
Unrealized gain	-	(15)
Foreign exchange gain	-	(25)
Balance at December 31, 2015	**78**	**$ 155**

On August 18, 2015 and November 27, 2015, the Corporation granted 15,000 and 30,000 restricted shares units (“RSUs”) with a reference price of C$2.28 and C$2.77 per share, respectively. The RSUs vest at 50% in one year and 50% in two years from the grant date, and will be settled in cash.

On October 2, 2015 and October 7, 2015, 117,388 and 8,000 RSUs were settled with a reference price of C$4.80 and C$4.70 per share, respectively.

Depletion and Depreciation Expense

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Depletion and depreciation expense	$ 13,906	$ 16,818	(17%)	$ 26,479	$ 61,262	(57%)
$/boe	$ 16.78	$ 16.03	5%	$ 14.58	$ 14.57	-

Depletion and depreciation expense decreased 17% in the three months ended December 31, 2015 compared to 2014 primarily as a result of the lower production during the quarter. Depletion and depreciation expense decreased 57% in the six months ended December 31, 2015 compared to the twelve months ended June 30, 2015 primarily as a result of the fact that a comparison is being made between a six month period versus a twelve month period.

Impairment on Development and Production Assets

	Three months ended December 31, 2015	Three months ended December 31, 2014	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Impairment on development and production assets	**$ 44,599**	$ 27,396	**$ 44,599**	$ 72,057

In light of weakness in benchmark crude oil prices, impairment tests were carried out at December 31, 2015 using forecasted crude oil price estimates. The impairment tests resulted in a write-down primarily related to the LLA-23, Capella and Santa Isabel assets totalling $44.6 million as at December 31, 2015. The Corporation's other fields were not affected.

Income Tax Expense

	Three months ended December 31, 2015	Three months ended December 31, 2014	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Current income tax expense (recovery)	**$ 647**	$ (1,403)	**$ 3,459**	$ 7,671
Deferred income tax expense (recovery)	**8,803**	4,880	**12,325**	(204)
Income tax expense	**$ 9,450**	$ 3,477	**$ 15,784**	$ 7,467

The Corporation's pre-tax income is subject to a combined Colombian statutory income tax rate of 39%. Included in the non-cash deferred income tax expense of $12.3 million in the six months ended December 31, 2015 was a $45.9 million non-cash deferred income tax expense charge attributable to the change in unrecognized tax benefit related to Colombian deferred tax asset and the impact of the devaluation of the Colombian peso versus the United States dollar on the Corporation's tax pools.

Cash and Funds from Operations and Comprehensive Loss

	Three months ended December 31, 2015	Three months ended December 31, 2014	Change	Six months ended December 31, 2015	Twelve months ended June 30, 2015	Change
Cash provided by operating activities	**$ 4,974**	$ 31,743	(84%)	**$ 19,276**	$ 64,445	(70%)
Per share – basic ($)	**$ 0.03**	$ 0.29	(90%)	**$ 0.14**	$ 0.58	(76%)
Per share – diluted ($)	**$ 0.03**	$ 0.29	(90%)	**$ 0.13**	$ 0.58	(78%)
Adjusted funds from operations (1)	**$ 8,473**	$ 22,952	(62%)	**$ 23,690**	$ 87,395	(73%)
Per share – basic ($)	**$ 0.05**	$ 0.21	(76%)	**$ 0.17**	$ 0.79	(78%)
Per share – diluted ($)	**$ 0.05**	$ 0.21	(76%)	**$ 0.16**	$ 0.78	(79%)
Comprehensive loss	**$ (84,466)**	$ (45,970)	84%	**$ (103,495)**	$ (106,022)	(2%)
Per share – basic ($)	**$ (0.54)**	$ (0.43)	26%	**$ (0.72)**	$ (0.96)	(25%)
Per share – diluted ($)	**$ (0.54)**	$ (0.43)	26%	**$ (0.72)**	$ (0.96)	(25%)

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

The comprehensive loss of $84.5 million for the three months ended December 31, 2015 was mainly driven by non-cash items that did not affect the core business of the Corporation. Most significantly, the non-cash depletion and depreciation expense of $13.9 million, the non-cash exploration expense of $8.7 million, the non-cash deferred income tax expense of $8.8 million and the non-cash impairment expense on development and production assets of $44.6 million.

The comprehensive loss of $103.5 million for the six months ended December 31, 2015 was mainly driven by non-cash items that did not affect the core business of the Corporation. Most significantly, the non-cash depletion and depreciation expense of $26.5 million, the non-cash exploration expense of $8.7 million, the non-cash deferred income tax expense of $12.3 million and the non-cash impairment expense on development and production assets of $44.6 million.

Capital Expenditures

	Three months ended December 31, 2015	Three months ended December 31, 2014	Six months ended December 31, 2015	Twelve months ended June 30, 2015
Drilling and completions	**$ 2,090**	$ 41,163	**$ 14,306**	$ 97,320
Facilities, work overs and infrastructure	**6,914**	5,827	**12,464**	18,276
Seismic, capitalized general and administrative expenses, capitalized borrowing cost and other non-cash costs (2)	**13,390**	12,987	**17,923**	47,791
Property acquisitions	**-**	37,609	**-**	75,609
Dispositions and farm-outs	**-**	(19,183)	**-**	(21,654)
Net capital expenditures	**22,394**	78,403	**44,693**	217,342
Ecuador	**473**	8,825	**4,254**	25,766
Adjusted net capital expenditures (1)	**$ 22,867**	$ 87,228	**$ 48,947**	$ 243,108
Net capital expenditures recorded as:				
Expenditures on exploration and evaluation assets	**$ 3,170**	$ 67,289	**$ 5,632**	$ 148,792
Expenditures on property, plant and equipment	**19,224**	30,297	**39,061**	90,204
Disposition and farm-outs	**-**	(19,183)	**-**	(21,654)
Net capital expenditures	**$ 22,394**	$ 78,403	**$ 44,693**	$ 217,342

(1) Non-IFRS measure – inclusive of amounts related to the Ecuador IPC – see "Non-IFRS Measures" section above.
(2) Other non-cash costs include capitalized stock-based compensation and capitalized costs related to decommissioning liabilities.

Capital expenditures for the three months ended December 31, 2015 primarily related to:

- Facilities costs at LLA-23;
- Drilling and facilities costs at Clarinete;
- Facilities costs at Esperanza;
- Drilling, completion and recompletion costs related to the Ecuador IPC (accounted for under the equity method of accounting); and
- Other capitalized costs (capitalized G&A of $0.9 million, non-cash decommissioning costs of $7.9 million, capitalized stock-based compensation of $0.5 million)

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, bank debt and working capital, defined as current assets less current liabilities. 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 its net debt level. Net debt is defined as the principal amount of its outstanding bank debt, less working capital, as defined above. In order to facilitate the management of its net debt, 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.

During the six months ended December 31, 2015, the Corporation took certain measures to counteract the weakness in crude oil prices over recent months and the resulting impact on cash flows. These measures include the strategic Cavengas financing and steps to reduce capital spending and preserve liquidity which, at December 31, 2015, had left the Corporation with $43.4 million in cash and $61.7 million in restricted cash. Further, at December 31, 2015 the Corporation had available an additional $25 million in committed debt facilities that it can draw down at any time up to April 27, 2016 at the sole discretion of the Corporation, subject to certain conditions. While crude oil prices are expected to remain weak into early 2016, significant new contracted gas deliveries are expected to commence shortly, thereby materially increasing revenues and funds from operations in early 2016 and significantly increasing the Corporation's revenues and field netbacks. In the meantime, the Corporation plans to maintain a prudent capital spending program and to focus on cost reductions to maximize profitability of the existing producing assets.

		December 31, 2015
Bank debt – principal	$	255,000
Working capital surplus		(46,310)
Net debt	**$**	**208,690**

Private Placement

On September 3, 2015, the Corporation completed a private placement with Cavengas Holding S.R.L, a Barbados company ("Cavengas"), for the amount of C$78,975,000 consisting of the issuance of 17,590,000 subscription receipts issued at C$2.50 per subscription receipt of the Corporation (the "Subscription Receipts") and convertible into 17,590,000 common shares of the Corporation (the "Common Shares"), along with the issuance of 14,000,000 Common Shares at a price of C$2.50 per Common Share. The C$35,000,000 related to the 14,000,000 Common Shares was released to the Corporation on September 3, 2015. On October 16, 2015, the 17,590,000 Subscription Receipts were converted into 17,590,000 Common Shares and the associated C$43,975,000 was released from escrow to the Corporation. The Corporation engaged an exclusive advisor for this transaction, and paid a fee of 3.5%, payable entirely in Common Shares, for their services.

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 led by Credit Suisse ("CS Senior Secured Term Loan"). The CS Senior Secured Term Loan was for a five-year term, with interest payable quarterly and principal repayable in 15 equal quarterly installments starting in October 2014, following an initial 18 month grace period. The CS 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 CS Senior Secured Term Loan, from $140 million to $220 million, with no changes to the terms of the CS 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.

On April 24, 2015, the CS Senior Secured Term Loan was settled for the principal amount outstanding on the settlement date of $176 million and was replaced with a new senior secured term loan with a syndicate of banks led by BNP Paribas for a principal amount of $200 million ("BNP Senior Secured Term Loan"). The carrying value of the CS Senior Secured Term Loan included $6.1 million of transaction costs netted against the principal amount and were fully expensed at the time of settlement. The BNP Senior Secured Term Loan is due September 30, 2019, with interest payable quarterly and principal repayable in eight equal quarterly installments beginning on December 31, 2017, following an initial grace period. As such, the BNP Senior Secured Term Loan is classified as non-current as at December 31, 2015. The BNP Senior Secured Term Loan carries interest at LIBOR plus 4.75% and is secured by all of the material assets of the Corporation. The carrying value of the BNP Senior Secured Term Loan included $3.9 million of transaction costs netted against the principal amount as at December 31, 2015. On September 30, 2015, the Corporation prepaid $20 million on the 2015 Credit Facility, thereby reducing the balance outstanding at December 31, 2015 to $180 million.

The BNP Senior Secured Term Loan includes various non-financial covenants relating to future acquisitions, indebtedness, operations, investments, capital expenditures and other standard operating business covenants. The BNP Senior Secured Term Loan also includes various financial covenants, including a maximum consolidated leverage ratio ("Consolidated Leverage Ratio") of 3.50:1.00, a minimum consolidated interest coverage ratio ("Consolidated Interest Coverage Ratio") of 2.50:1.00 and a minimum consolidated current assets to consolidated current liabilities ratio ("Consolidated Current Assets to Consolidated Current Liabilities Ratio") of 1.00:1.00.

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 3.50:1.00, except for the period ended December 31, 2015 whereby the allowable Consolidated Leverage Ratio was increased from 3.50:1.00 to 4.00:1.00. As at December 31, 2015, the Consolidated Leverage Ratio was 3.74:1.00. Consolidated Total Debt includes the principal amount of all indebtedness, which currently includes bank debt; additionally, restricted cash maintained in the debt service reserve account related to the BNP 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. 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, 2015**
Bank debt (current and long-term) – principal	$	255,000
Debt service reserve account balance		(3,000)
Consolidated Total Debt	$	252,000

Consolidated EBITDAX	**Mar 31, 2015**	**Jun 30, 2015**	**Sep 30, 2015**	**Dec 31, 2015**	**Rolling**
Consolidated net loss	(15,638)	(58,524)	(19,029)	(84,462)	(177,653)
(+) Interest expense	5,672	14,122	6,250	5,575	31,619
(+/-) Income taxes (recovery)	7,116	(1,936)	6,334	9,450	20,964
(+) Wealth taxes	1,519	(18)	-	-	1,501
(+) Depletion and depreciation	12,289	12,662	12,573	13,906	51,430
(+) Exploration expenses	98	19	52	8,796	8,965
(-) Share of joint venture (profit) loss	(675)	(208)	135	(537)	(1,285)
(+/-) Other non-cash expenses (income) and non-recurring items	(1,129)	47,570	4,361	52,620	103,422
(+) Contribution of Ecuador IPC	6,382	6,595	7,941	7,481	28,399
Consolidated EBITDAX	15,634	20,282	18,617	12,829	67,362

Consolidated Leverage Ratio		**December 31, 2015**
Consolidated Total Debt	$	252,000
Consolidated EBITDAX		67,362
Consolidated Leverage Ratio		3.74

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 2.50:1.00. 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 and capitalized interest, net of interest income, and excludes any non-cash interest charges.

Consolidated Interest Coverage Ratio		**December 31, 2015**
Interest expense	$	22,460
Capitalized interest		817
Interest income		(2,590)
Consolidated Interest Expense	$	20,687
Consolidated EBITDAX	$	67,362
Consolidated Interest Coverage Ratio		3.26

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 and any non-cash current assets and non-cash current liabilities. The minimum Consolidated Current Assets to Consolidated Current Liabilities Ratio required is 1.00:1.00. As at December 31, 2015, the Consolidated Current Assets to Consolidated Current Liabilities Ratio was 2.93:1.00.

The Corporation was in compliance with its covenants as at December 31, 2015.

Senior Notes

On October 29, 2014, the Corporation entered into the $100 million unsecured floating rate senior note indenture agreement with Apollo Investment Corporation ("Senior Notes"), with $50 million drawn and funded on October 29, 2014, $25 million drawn and funded on April 2, 2015, and a further $25 million committed and available to be drawn at any time up to April 27, 2016 at the sole discretion of the Corporation, subject to certain 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 BNP Senior Secured Term Loan. Standby fees on the undrawn portion of the Senior Notes are calculated at 1% per annum. The carrying value of the Senior Notes included $2.9 million of transaction costs netted against the principal amount as at December 31, 2015.

Other Colombian Credit Facilities

The Corporation has revolving lines of credit in place in Colombia with an aggregate borrowing base of $39.4 million (COP$ 124 billion). These lines of credit have interest rates ranging from 6% to 9% and are unsecured. The facilities were undrawn as at and during the year ended December 31, 2015.

Letters of Credit

At December 31, 2015, the Corporation had letters of credit outstanding totaling $66.5 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 $34.9 million to $4.5 million at December 31, 2015.

Share Capital

At March 22, 2016, the Corporation had 159.4 million common shares, 14.6 million stock options, and 0.1 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, 2015:

	Less than 1 year	1-3 years	Thereafter	Total
Bank debt – principal	$ -	$ 112,500	$ 142,500	$ 255,000
Trade and other payables	12,704	-	-	12,704
Crude oil payable in kind	721	-	-	721
Taxes payable	8,315	-	-	8,315
Deferred income	2,216	-	3,731	5,947
Other long term obligations	-	-	2,801	2,801
Restricted share units	100	55	-	155
Exploration and production contracts	26,963	84,751	-	111,714
Office leases	799	1,363	1,947	4,109
Finance lease	7,519	19,793	20,990	48,302

Exploration and Production Contracts

The Corporation has entered into a number of exploration contracts in Colombia which require the Corporation to fulfill work program commitments and to issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at December 31, 2015 of $111.7 million and has issued $49.7 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 commitments 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, 2015, the Corporation had incurred $83.0 million of expenditures in connection with its Ecuador IPC commitment.

OUTLOOK

Despite the downturn in world commodity prices, during the final six months of calendar 2015, and 2016 to date, Canacol has focused on growing its high net back gas business. This growth is reflected by both the increase in gas production, which will reach 90 MMscfpd at the end of March 2016 and generate approximately $163 million in gross revenues this year, and the increase in value of the Corporation's 2P reserves which now stand at 79 MMboe, 80% of which are now gas, with a before tax undiscounted value of $1.3 billion or C$9.44 per share. These reserves do not include the recent Oboe-1 well, which tested at a combined rate of 66 MMscfpd.

During this timeframe the Corporation has had many operational and financial accomplishments:

- The drilling of the recent Clarinete-2ST well and its combined test results of over 30 MMscf/d in October, 2015.
- The drilling of Oboe-1 and its combined test results of over 66 MMscf/d (11,579 boe/d), in 2016.
- The completion of the upgrade, on schedule, of the Canacol owned Jobo gas processing plant to now process 80 MMscf/d of gas.
- The current commissioning and testing of the completed Promisol Jobo gas plant to process an additional 100 mmcf/d of gas, bringing Canacol's total gas processing capability to 180 MMscf/d.
- The tying-in of both Clarinete-1 and Clarinete-2ST to the Jobo plant via a 12 km 6" flow-line, such that both are now capable of delivering gas.
- The strategic investment with Cavengas for C$79 million in September, 2015, which allowed for both a partial repayment of debt and the ability to maintain a flexible capital expenditure program as the corporation continues to focus on developing its substantial natural gas portfolio.

Additionally, Canacol has been actively reducing its costs in 2016:

- A planned 2016 Capex budget of $52 million, down 37% from the $82 million spent in calendar 2015.
- Continued reductions on LLA-23 costs, to post six months ended December 31, 2015, operating costs of $8.74/boe, almost half of the $15.90/boe for the twelve months ended June, 2015.
- Aggressive G&A reductions, including employee layoffs.

The Corporation's recently released December 31, 2015 NI 51-101 compliant reserves reports showed marked increases during 2015 as a result of gas drilling, and allowed the Corporation to post some of the best metrics in the industry. Highlights included:

- Proven developed producing ("PDP") reserves increased by 110% since June 30, 2015, to total 28.4 MMboe at December 31, 2015.
- Proved plus probable ("2P") reserves totaled 79.2 MMboe at December 31, 2015, with a before tax value discounted at 10% of $1.3 billion, being C$9.44 per share.
- Achieved a 2P reserve replacement of 1,013%, based on calendar 2015 gross reserve additions of 30.3 MMboe, being more than 10 times of those produced in the same period.
- Achieved a 1P reserve replacement of 656% based on calendar 2015 gross proven reserve additions of 19.7 MMboe.
- Achieved 2P finding and development costs ("F&D") of $1.81/boe for its gas assets and $2.85/boe as a corporate total for calendar 2015.
- Recorded 2P finding, development and acquisition costs ("FD&A") of $2.44/boe for its gas assets and $3.38/boe as a corporate total for calendar 2015.
- Recorded a 2P reserves life index ("RLI") of 24 years based on 2015 production, and a 10 year RLI based on expected future gas production of 90 MMscfpd upon the completion of the Promigas pipeline expansion (1P RLI being 16 years and 7 years, respectively).

Looking forward to the remainder of 2016, management shall remain focused on:

1) Disciplined capital spending with anticipated capex of $52 million predicated on a WTI price of $30/bbl for the first half of 2016, and $35/bbl for the second half of 2016,

2) Continuing to grow Canacol's Colombian gas reserves and production base through its exploration program targeting 100 BCF (18 MMboe) of unrisked reserve potential, which has commenced with the recently announced success at Oboe-1 which tested at a combined rate of 66 MMscfpd,

3) Negotiating the construction of a new gas pipeline which will send 100 MMscpfd of new Canacol gas production to the Caribbean coast of Colombia in 2018, and

4) Maintaining Canacol's large inventory of light oil drill ready production and exploration opportunities which could be rapidly executed should global oil prices recover to a reasonable level and justify capital investment.

SUMMARY OF QUARTERLY RESULTS

	2016		2015				2014	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Financial								
Petroleum and natural gas revenues, net of royalties	**16,472**	21,958	27,297	26,429	36,404	58,917	61,744	55,653
Adjusted petroleum and natural gas revenues, net of royalties, including revenues relate to the Ecuador IPC (1)	**23,953**	29,899	33,892	32,811	43,878	67,356	68,975	62,437
Cash provided by operating activities	**4,974**	14,302	(10,905)	(2,011)	31,743	45,618	8,715	13,009
Per share – basic	**0.03**	0.11	(0.09)	(0.02)	0.29	0.42	0.09	0.15
Per share – diluted	**0.03**	0.11	(0.09)	(0.02)	0.29	0.42	0.09	0.15
Adjusted funds from operations (1)	**8,473**	15,218	16,359	10,922	22,952	37,162	23,995	33,161
Per share – basic (1)	**0.05**	0.12	0.14	0.10	0.21	0.34	0.25	0.37
Per share – diluted (1)	**0.05**	0.12	0.14	0.10	0.21	0.34	0.24	0.36
Comprehensive income (loss)	**(84,466)**	(19,029)	(58,524)	(15,638)	(45,970)	14,110	(2,070)	19,438
Per share – basic	**(0.54)**	(0.15)	(0.50)	(0.14)	(0.43)	0.13	(0.02)	0.22
Per share – diluted	**(0.54)**	(0.15)	(0.50)	(0.14)	(0.43)	0.13	(0.02)	0.21
Capital expenditures, net	**22,394**	22,299	25,310	62,482	78,403	47,522	77,093	35,915
Adjusted capital expenditures, net, including capital expenditures related to the Ecuador IPC (1)	**22,867**	26,080	27,268	68,778	87,228	56,209	87,584	44,103
Operations (boepd)								
Petroleum and natural gas **production**, before royalties								
Petroleum (2)	**5,523**	6,983	6,007	7,448	8,586	9,922	9,271	8,260
Natural gas	**3,541**	3,472	3,954	3,502	3,236	3,334	2,941	2,633
Total (2)	**9,064**	10,455	9,961	10,950	11,822	13,256	12,212	10,893
Petroleum and natural gas **sales**, before royalties								
Petroleum (2)	**5,468**	7,272	6,192	7,636	8,187	9,997	9,386	8,792
Natural gas	**3,542**	3,455	4,064	3,462	3,216	3,311	2,937	2,626
Total (2)	**9,010**	10,727	10,256	11,098	11,403	13,308	12,323	11,418

(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.

SUPPLEMENTAL FINANCIAL INFORMATION

Fiscal year ended	**December 31, 2015**	June 30, 2015	June 30, 2014
Total assets	**$ 668,349**	$ 669,742	$ 756,587
Total bank debt	**248,228**	267,023	210,688
Petroleum and natural gas revenues, net of royalties	**38,430**	149,047	207,787
Comprehensive income (loss)	**(103,495)**	(106,022)	9,937
Per share – basic ($)	**(0.72)**	(0.96)	0.11
Per share – diluted ($)	**(0.72)**	(0.96)	0.11

RISKS AND UNCERTAINTIES

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 the Corporation's business plan. Although periodic volatility of financial and capital markets may severely limit access to capital, the Corporation has been able to successfully attract capital in the past.

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 and the Canadian dollar.

Most of the Corporation's revenues and funds from financing activities are expected to be received in reference to United States dollar ("US dollar") denominated prices while a portion of its operating, capital, and general and administrative costs are denominated in Colombian Pesos and Canadian dollars. The Colombian Peso has seen significant variation against the US dollar in the past and it continues to have significant daily fluctuations. The Corporation has not entered into any currency derivatives in order to reduce its exposure to fluctuations that the US dollar may incur.

The Corporation is exposed to interest rate risk on certain variable interest rate debt instruments, to the extent they are drawn. The remainder of the Corporation's financial assets and liabilities are not exposed to interest rate risk. The Corporation had no interest rate swap or financial contracts in place as at or during the six months ended December 31, 2015.

Fluctuations in energy prices will not only impact revenues of the Corporation but may also impact the Corporation's ability to raise capital. Commodity prices for crude oil are impacted by world economic events that dictate the levels of supply and demand. From time to time the Corporation may attempt to mitigate commodity price risk through the use of financial derivatives. The Corporation's policy is to only enter into commodity contracts considered appropriate to a maximum of 50% of forecasted production volumes. The Corporation had no commodity price contracts in place as at or during the six months ended December 31, 2015.

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 maximization. To date, the Corporation has not experienced any material credit loss in the collection of trade accounts receivable.

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.

A more comprehensive discussion of risks and uncertainties is contained in the Corporation's Annual Information Form for the six months ended December 31, 2015 as filed on SEDAR and hereby incorporated by reference.

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 financial statements of the Corporation as at and for the six months ended December 31, 2015.

REGULATORY POLICIES

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("DC&P") are designed to provide reasonable assurance that all material information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure and that information required to be disclosed by the issuer under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. 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, DC&P and have assessed the design and operating effectiveness of the Corporation's DC&P as at December 31, 2015. Based on this assessment, it was concluded that the design and operation of the Corporation's DC&P are effective as at December 31, 2015.

Internal Control over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate Internal Control over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS. The Corporation's CEO and CFO, with support of management have assessed the design and operating effectiveness of the Corporation's ICFR as at December 31, 2015 based on criteria described in "Internal Control – Integrated Framework" issued in 2013 by the Committee of Sponsoring Organization of the Treadway Commission. Based on this assessment, it was concluded that the design and operation of the Corporation's ICFR are effective as at December 31, 2015.

During the quarter ended December 31, 2015, 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.