(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	2016
Accounts receivable and other long-term assets	**$ (2,428)**	$ (2,513)
Inventory	**207**	4,339
Prepaids	**1,078**	466
Accounts payable and accrued and other long-term liabilities	**4,310**	(5,975)
Taxes receivable and payable	**1,763**	3,036
Net changes in assets and liabilities from operating activities	**$ 4,930**	$ (647)

The following table provides additional supplemental cash flow disclosures:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	2016
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	**$ 54,875**	$ 35,606

Item 2. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language at the very beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well as Part II, Item 1A "Risk Factors" in this Quarterly Report on Form 10-Q and Part I, Item 1A "Risk Factors" in our 2016 Annual Report on Form 10-K.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our Annual Report on Form 10-K, filed with the SEC on March 1, 2017.

Highlights

Acquisition of the Santana and Nancy-Burdine-Maxine Blocks

Subsequent to the end of the quarter, on April 27, 2017, we acquired the Santana and Nancy-Burdine-Maxine Blocks for cash consideration of $30.4 million. These two blocks were offered by Ecopetrol as part of an asset disposition process and are located in the Putumayo Basin.

Financial and Operational Highlights

	Three Months Ended December 31	Three Months Ended March 31,		
	2016	2017	2016	% Change
Volumes (BOE)				
Working Interest Production Before Royalties	2,854,852	**2,689,146**	2,330,539	15
Royalties	(438,656)	**(457,990)**	(256,803)	78
Production NAR	2,416,196	**2,231,156**	2,073,736	8
Decrease in Inventory	19,688	**1,584**	240,424	(99)
Sales(1)	2,435,884	**2,232,740**	2,314,160	(4)
Average Daily Volumes (BOEPD)				
Working Interest Production Before Royalties	31,031	**29,879**	25,610	17
Royalties	(4,768)	**(5,089)**	(2,822)	80
Production NAR	26,263	**24,790**	22,788	9
Decrease in Inventory	214	**18**	2,642	(99)
Sales(1)	26,477	**24,808**	25,430	(2)
Operating Netback ($000s)				
Oil and Natural Gas Sales	$ 91,614	**$ 94,659**	$ 57,403	65
Operating Expenses	(24,472)	**(23,937)**	(19,067)	26
Transportation Expenses	(7,458)	**(6,942)**	(12,328)	(44)
Operating Netback(2)	$ 59,684	**$ 63,780**	$ 26,008	145
G&A Expenses, Including Stock-Based Compensation ($000s)	$ 12,604	**$ 8,712**	$ 7,049	24
Net (Loss) Income ($000s)	$ (127,355)	**$ 12,771**	$ (45,032)	128
EBITDA ($000s)(3)	$ 30,745	**$ 61,538**	$ 24,184	154
Net Cash Provided by Operating Activities ($000s)	$ 6,643	**$ 49,943**	$ 10,812	362
Funds Flow From Operations ($000s)(4)	$ 36,186	**$ 45,026**	$ 11,563	289
Capital Expenditures ($000s)	$ 58,219	**$ 46,160**	$ 26,180	76

	As at		
(Thousands of U.S. Dollars)	March 31, 2017	December 31, 2016	% Change
Cash, Cash Equivalents and Current Restricted Cash and Cash Equivalents	**$ 34,379**	$ 33,497	3
Revolving Credit Facility	**$ 85,000**	$ 90,000	(6)
Convertible Senior Notes	**$ 115,000**	$ 115,000	—

(1) Sales volumes represent production NAR adjusted for inventory changes.

Non-GAAP measures

Operating netback, EBITDA, and funds flow from operations are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Management views operating netback and EBITDA as financial performance measures and funds flow from operations as a liquidity measure. Investors are cautioned that these measures should not be construed as alternatives to net loss or other measures of financial performance or liquidity as determined in accordance with GAAP. Our method of calculating these measures may differ from other companies and, accordingly, may not be comparable to similar measures used by other companies. Each non-GAAP financial measure is presented along with the corresponding GAAP measure so as not to imply that more emphasis should be placed on the non-GAAP measure.

(2) Operating netback as presented is oil and gas sales net of royalties and operating and transportation expenses. Management believes that netback is a useful supplemental measure for management and investors to analyze financial performance and provides an indication of the results generated by our principal business activities prior to the consideration of other income and expenses.

(3) EBITDA, as presented, is net income or loss adjusted for depletion, depreciation and accretion ("DD&A") expenses, asset impairment, interest expense and income tax recovery or expense. Management uses these financial measures to analyze performance and income or loss generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that these financial measures are also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income or loss to EBITDA is as follows:

	Three Months Ended December 31	Three Months Ended March 31,	
EBITDA - Non-GAAP Measure ($000s)	**2016**	**2017**	**2016**
Net (loss) income	$ (127,355)	**$ 12,771**	$ (45,032)
Adjustments to reconcile net (loss) income to EBITDA			
DD&A expenses	35,010	**26,593**	36,912
Asset impairment	146,934	**283**	56,898
Interest expense	6,303	**3,095**	519
Income tax (recovery) expense	(30,147)	**18,796**	(25,113)
EBITDA	$ 30,745	**$ 61,538**	$ 24,184

(4) Funds flow from operations, as presented, is net cash provided by operating activities adjusted for net change in assets and liabilities from operating activities and cash settlement of asset retirement obligation. Management uses this financial measure to analyze liquidity and cash flows generated by our principal business activities prior to the consideration of how changes in assets and liabilities from operating activities and cash settlement of asset retirement obligation affect those cash flows, and believes that this financial measure is also useful supplemental information for investors to analyze our liquidity and financial results. A reconciliation from net cash provided by operating activities to funds flow from operations is as follows:

	Three Months Ended December 31	Three Months Ended March 31,	
Funds Flow From Operations - Non-GAAP Measure ($000s)	**2016**	**2017**	**2016**
Net cash provided by operating activities	$ 6,643	**49,943**	$ 10,812
Adjustments to reconcile net cash provided by operating activities to funds flow from operations			
Net change in assets and liabilities from operating activities	29,434	**(4,930)**	647
Cash settlement of asset retirement obligation	109	**13**	104
Funds flow from operations	$ 36,186	**$ 45,026**	$ 11,563

Consolidated Results of Operations

(Thousands of U.S. Dollars)	Three Months Ended December 31 2016	Three Months Ended March 31, 2017	Three Months Ended March 31, 2016	% Change
Oil and natural gas sales	$ 91,614	**$ 94,659**	$ 57,403	65
Operating expenses	24,472	**23,937**	19,067	26
Transportation expenses	7,458	**6,942**	12,328	(44)
Operating netback[1]	59,684	**63,780**	26,008	145
DD&A expenses	35,010	**26,593**	36,912	(28)
Asset impairment	146,934	**283**	56,898	(100)
G&A expenses before stock-based compensation	10,713	**7,563**	5,652	34
Stock-based compensation expense	1,891	**1,149**	1,397	(18)
Transaction expenses	—	**—**	1,237	(100)
Severance expenses	20	**—**	1,018	(100)
Equity tax	45	**1,224**	3,051	(60)
Foreign exchange (gain) loss	(2,528)	**(1,847)**	785	(335)
Financial instruments loss (gain)	8,455	**(5,439)**	845	(744)
Interest expense	6,303	**3,095**	519	496
	206,843	**32,621**	108,314	(70)
(Adjustment to gain)/gain on acquisition	(10,783)	**—**	11,712	(100)
Interest income	440	**408**	449	(9)
(Loss) income before income taxes	(157,502)	**31,567**	(70,145)	145
Current income tax expense	(8,442)	**(7,417)**	(2,023)	267
Deferred income tax recovery (expense)	38,589	**(11,379)**	27,136	142
	30,147	**(18,796)**	25,113	175
Net (loss) income	$ (127,355)	**$ 12,771**	$ (45,032)	128
Sales Volumes				
Oil and NGL's, bbl	2,394,098	**2,195,214**	2,292,116	(4)
Natural gas, Mcf	250,713	**225,158**	132,265	70
Total sales volumes, BOE	2,435,884	**2,232,740**	2,314,160	(4)
Total sales volumes, BOEPD	26,477	**24,808**	25,430	(2)
Average Prices				
Oil and NGL's per bbl	$ 38.16	**$ 42.96**	$ 24.88	73
Natural gas per Mcf	$ 1.05	**$ 1.52**	$ 2.83	(46)
Brent Price per bbl	$ 51.13	**$ 54.66**	$ 33.70	62

Consolidated Results of Operations per BOE Sales Volumes NAR				
Oil and natural gas sales	$ 37.61	**$ 42.40**	$ 24.81	71
Operating expenses	10.05	**10.72**	8.24	30
Transportation expenses	3.06	**3.11**	5.33	(42)
Operating netback[1]	24.50	**28.57**	11.24	154
DD&A expenses	14.37	**11.91**	15.95	(25)
Asset impairment	60.32	**0.13**	24.59	(99)
G&A expenses before stock-based compensation	4.39	**3.39**	2.45	38
Stock-based compensation expense	0.78	**0.51**	0.60	(15)
Transaction expenses	—	**—**	0.53	(100)
Severance expenses	0.01	**—**	0.44	(100)
Equity tax	0.02	**0.55**	1.32	(58)
Foreign exchange (gain) loss	(1.04)	**(0.83)**	0.34	344
Financial instruments loss (gain)	3.47	**(2.44)**	0.37	759
Interest expense	2.59	**1.39**	0.22	532
	84.91	**14.61**	46.81	(69)
(Adjustment to gain)/gain on acquisition	(4.43)	**—**	5.06	(100)
Interest income	0.18	**0.18**	0.19	(5)
(Loss) income before income taxes	(64.66)	**14.14**	(30.32)	147
Current income tax expense	(3.47)	**(3.32)**	(0.87)	282
Deferred income tax recovery (expense)	15.84	**(5.10)**	11.73	143
	12.37	**(8.42)**	10.86	178
Net (loss) income	$ (52.29)	**$ 5.72**	$ (19.46)	129

[1] Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to non-GAAP measures disclosure above regarding this measure.

Oil and Gas Production and Sales Volumes, BOEPD

	Three Months Ended March 31, 2017			Three Months Ended March 31, 2016		
Average Daily Volumes (BOEPD)	**Colombia**	**Brazil**	**Total**	**Colombia**	**Brazil**	**Total**
Working Interest Production Before Royalties	**28,481**	**1,398**	**29,879**	24,886	724	25,610
Royalties	**(4,868)**	**(221)**	**(5,089)**	(2,676)	(146)	(2,822)
Production NAR	**23,613**	**1,177**	**24,790**	22,210	578	22,788
Decrease (Increase) in Inventory	**7**	**11**	**18**	2,647	(5)	2,642
Sales	**23,620**	**1,188**	**24,808**	24,857	573	25,430
Royalties, % of Working Interest Production Before Royalties	**17%**	**16%**	**17%**	11 %	20 %	11 %

Oil and gas production NAR for the three months ended March 31, 2017, increased by 9% to 24,790 BOEPD, compared with 22,788 BOEPD in the corresponding period in 2016. In the three months ended March 31, 2017, production increased primarily due to production from the Acordionero Field acquired in the PetroLatina acquisition and a successful drilling campaign in the Costayaco, Moqueta and Acordionero Fields in Colombia. In Brazil, oil and gas production NAR for the three months ended

March 31, 2017, increased by 599 BOEPD as a result of higher allowable oil production due to the commencement of gas compression as well as the sale of these gas volumes. Royalties as a percentage of production increased from the prior year commensurate with the increase in oil prices.

Oil and gas production NAR for the three months ended March 31, 2017, decreased 6% compared with the prior quarter due to well downtime from workovers in the Costayaco Field and pump failures in both Acordionero and Cumplidor.

Oil and gas sales volumes for the three months ended March 31, 2017, decreased by 2% to 24,808 BOEPD compared with 25,430 BOEPD in the corresponding period in 2016. Higher working interest production (4,269 BOEPD) was more than offset by the combination of higher royalty volumes (2,267 BOEPD) and smaller inventory decreases (2,624 BOEPD). During the three months ended March 31, 2017, oil inventory decreases accounted for 18 bopd of increased sales volumes compared with oil inventory decreases in the corresponding period in 2016, which accounted for 2,642 bopd of increased sales volumes.

Oil and gas sales volumes for the three months ended March 31, 2017, decreased by 6% to 24,808 BOEPD compared with 26,477 BOEPD in the prior quarter. Sales volumes decreased due to lower working interest production (1,152 BOEPD), higher royalty volumes (321 BOEPD) and the effect of inventory changes (196 BOEPD).

Operating Netbacks

	Three Months Ended March 31, 2017			**Three Months Ended March 31, 2016**		
(Thousands of U.S. Dollars)	**Colombia**	**Brazil**	**Total**	**Colombia**	**Brazil**	**Total**
Oil and Natural Gas Sales	**$ 90,464**	**$ 4,195**	**$ 94,659**	$ 56,300	$ 1,103	$ 57,403
Transportation Expenses	**(6,765)**	**(177)**	**(6,942)**	(12,256)	(72)	(12,328)
	83,699	**4,018**	**87,717**	44,044	1,031	45,075
Operating Expenses	**(23,156)**	**(781)**	**(23,937)**	(19,164)	97	(19,067)
Operating Netback(1)	**$ 60,543**	**$ 3,237**	**$ 63,780**	$ 24,880	$ 1,128	$ 26,008
U.S. Dollars Per BOE Sales Volumes NAR						
Brent	**$ 54.66**	**$ 54.66**	**$ 54.66**	$ 33.70	$ 33.70	$ 33.70
Quality and Transportation Discounts	**(12.11)**	**(15.42)**	**(12.26)**	(8.81)	(12.57)	(8.89)
Average Realized Price	**42.55**	**39.24**	**42.40**	24.89	21.13	24.81
Transportation Expenses	**(3.18)**	**(1.66)**	**(3.11)**	(5.42)	(1.38)	(5.33)
Average Realized Price Net of Transportation Expenses	**39.37**	**37.58**	**39.29**	19.47	19.75	19.48
Operating Expenses	**(10.89)**	**(7.31)**	**(10.72)**	(8.47)	1.86	(8.24)
Operating Netback(1)	**$ 28.48**	**$ 30.27**	**$ 28.57**	$ 11.00	$ 21.61	$ 11.24

(1) Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to non-GAAP measures disclosure above regarding this measure.

Oil and gas sales for the three months ended March 31, 2017, increased by 65% to $94.7 million from $57.4 million in the comparable period in 2016 primarily due to increased realized oil prices. The following table shows the effect of changes in realized prices and sales volumes on our oil and gas sales for the three months ended March 31, 2017:

	First Quarter 2017 Compared with Fourth Quarter 2016	**First Quarter 2017 Compared with First Quarter 2016**
Oil and natural gas sales for the comparative period	$ 91,614	$ 57,403
Realized sales price increase effect	10,685	39,276
Sales volume decrease effect	(7,640)	(2,020)
Oil and natural gas sales for period ended March 31, 2017	**$ 94,659**	**$ 94,659**

Average realized prices for the three months ended March 31, 2017, increased by 71%, commensurate with the increase in benchmark oil prices. Average Brent oil prices for the three months ended March 31, 2017, increased by 62%. In Brazil, in the three months ended March 31, 2017, the differential between our average realized price and Brent per BOE increased as a result of higher gas sales.

Oil and gas sales for the three months ended March 31, 2017, increased by 3% to $94.7 million from $91.6 million compared with the prior quarter primarily due to increased realized oil prices, partially offset by lower sales volumes. Average realized prices increased by 13% to $42.40 per BOE for the three months ended March 31, 2017, compared with $37.61 per BOE in the prior quarter. Average Brent oil prices for the three months ended March 31, 2017, increased by 7% to $54.66 per bbl, compared with $51.13 per bbl in the prior quarter.

During periods of CENIT S.A-operated Trans-Andean oil pipeline (the "OTA pipeline") disruptions, we have multiple transportation alternatives. Each transportation route has varying effects on realized prices and transportation expenses. The following table shows the percentage of oil volumes we sold in Colombia using each transportation method for the three months ended March 31, 2017 and 2016 and the prior quarter:

	Three Months Ended December 31	Three Months Ended March 31,	
	2016	2017	2016
Volume transported through pipeline	29%	**25%**	67%
Volume sold at wellhead, trucking	49%	**50%**	17%
Volume sold not at wellhead, trucking	22%	**25%**	16%
	100%	**100%**	100%

Volume not sold at the wellhead receives a higher realized price, but incurs higher transportation expense. Volume sold at the wellhead has the opposite effect of lower realized price, offset by lower transportation expense.

Transportation expenses for the three months ended March 31, 2017, decreased by 44% to $6.9 million compared with the corresponding period in 2016. On a per BOE basis, transportation expenses decreased by 42% to $3.11 per BOE from $5.33 per BOE in the corresponding period in 2016. The decrease in transportation expenses per BOE was due to a higher percentage of volumes sold at the wellhead, as noted in the table above, and the use of alternative transportation routes, which had lower costs per BOE than the routes used in 2016.

Transportation expenses for the three months ended March 31, 2017, decreased 7% to $6.9 million compared with $7.5 million in the prior quarter. On a per BOE basis, transportation expenses increased by 2% to $3.11 from $3.06 in the prior quarter. The increase was primarily due to a higher percentage of trucked sales in the current quarter.

The following table shows the variance in our ***average realized prices net of transportation expenses*** in Colombia for the three months ended March 31, 2017 compared with the comparative period in 2016 and the prior quarter:

U.S. Dollars Per BOE Sales Volumes NAR	**First Quarter 2017 Compared with Fourth Quarter 2016**	**First Quarter 2017 Compared with First Quarter 2016**
Average realized price net of transportation expenses for the comparative period	$ 34.50	$ 19.47
Increase in benchmark prices	3.53	20.96
Decrease (increase) in quality and transportation discounts	1.43	(3.30)
(Higher) lower transportation expenses	(0.09)	2.24
Average realized price net of transportation expenses for period ended March 31, 2017	**$ 39.37**	**$ 39.37**

Operating expenses for the three months ended March 31, 2017, increased by 26% to $23.9 million, compared with the corresponding period in 2016. On a per BOE basis, operating expenses increased by 30% to $10.72 per BOE from $8.24 per BOE in the corresponding period in 2016.

Colombian operating expense for the three months ended March 31, 2017, increased by $2.42 per BOE compared with the corresponding period in 2016. Workover expenses in Colombia increased by $0.74 per BOE compared with the corresponding period in 2016, and the remainder of the increase is primarily due to the cost of renting additional water injection equipment, and the effect of lower sales volumes in the three months ended March 31, 2017.

In Brazil, the comparative period in 2016 included a $7.97 per bbl reduction in operating expenses based on volumes sold in Brazil, after we settled a one-time penalty for less than estimated.

Operating expenses decreased by 2% to $23.9 million in the three months ended March 31, 2017, compared with $24.5 million in the prior quarter. On a per BOE basis, operating expenses increased by 7% to $10.72 per BOE for the three months ended March 31, 2017, from $10.05 per BOE in the prior quarter primarily due to lower sales volumes and the relationship between fixed and variable costs.

DD&A Expenses

	Three Months Ended March 31, 2017		Three Months Ended March 31, 2016	
	DD&A expenses, thousands of U.S. Dollars	**DD&A expenses, U.S. Dollars Per BOE**	**DD&A expenses, thousands of U.S. Dollars**	**DD&A expenses, U.S. Dollars Per BOE**
Colombia	**$ 24,935**	**$ 11.73**	$ 35,736	$ 15.80
Brazil	**1,213**	**11.35**	718	13.75
Peru	**226**	**—**	141	—
Corporate	**219**	**—**	317	—
	$ 26,593	**$ 11.91**	$ 36,912	$ 15.95

DD&A expenses for the three months ended March 31, 2017, decreased to $26.6 million ($11.91 per BOE) from $36.9 million ($15.95 per BOE) in the corresponding period in 2016. DD&A expenses decreased by 17% to $11.91 per BOE for the three months ended March 31, 2017, from $14.37 per BOE in the prior quarter. On a per BOE basis, the decrease was due to lower costs in the depletable base and increased proved reserves.

Asset Impairment

We follow the full cost method of accounting for our oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated “ceiling”. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year and it should not be assumed that estimates of future net revenues represent the fair market value of our reserves.

In accordance with GAAP, we used an average Brent price of $49.33 per bbl for the purposes of the March 31, 2017, ceiling test calculations (December 31 2016 - $42.92; March 31, 2016 - $48.79; December 31, 2015 - $54.08). In the comparative period in 2016 ceiling test impairment losses in our Colombia and Brazil cost centers and inventory impairment were primarily due to lower oil prices.

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	2016
Impairment of oil and gas properties		
Colombia	**$ —**	$ 54,568
Brazil	**—**	1,250
Peru	**283**	416
	283	56,234
Impairment of inventory	**—**	664
	$ 283	$ 56,898

G&A Expenses

(Thousands of U.S. Dollars)	Three Months Ended December 31 2017	Three Months Ended March 31, 2017	2016	% Change
G&A Expenses Before Stock-Based Compensation	$ 10,713	**$ 7,563**	$ 5,652	34
Stock-Based Compensation	1,891	**1,149**	1,397	(18)
G&A Expenses, Including Stock-Based Compensation	$ 12,604	**$ 8,712**	$ 7,049	24
U.S. Dollars Per BOE				
G&A Expenses Before Stock-Based Compensation	$ 4.39	**$ 3.39**	$ 2.45	38
Stock-Based Compensation	0.78	**0.51**	0.60	(15)
G&A Expenses, Including Stock-Based Compensation	$ 5.17	**$ 3.90**	$ 3.05	28

G&A expenses for the three months ended March 31, 2017, increased by 24% to $8.7 million ($3.90 per BOE) from $7.0 million ($3.05 per BOE) in the corresponding period in 2016. The increase was primarily due to higher salaries as a result of increased headcount and expanded operations, partially offset by increased capitalization of costs as result of higher capital activity. G&A expenses for the three months ended March 31, 2017, decreased by 31% to $8.7 million ($3.90 per BOE) compared with $12.6 million ($5.17 per BOE) in the prior quarter.

Transaction Expenses

For the three months ended March 31, 2017, transaction expenses were $nil compared with $1.2 million in the corresponding period in 2016. Transaction expenses in the comparative period in 2016, related to our acquisition of Petroamerica Oil Corp. ("Petroamerica"),

Severance Expenses

For the three months ended March 31, 2017, severance expenses were $nil compared with $1.0 million in the corresponding period in 2016. Severance expenses in the comparative period in were consistent with the decrease in headcount.

Equity Tax Expense

For the three months ended March 31, 2017 and 2016, equity tax expense was $1.2 million and $3.1 million, respectively, and is a tax calculated based on our Colombian legal entities' balance sheets equity at January 1. The legal obligation for each year's equity tax liability arises on January 1 of each year, therefore, we recognize the annual amounts of the equity tax expense in our interim unaudited condensed consolidated statement of operations during the first quarter of each year.

Foreign Exchange Gains and Losses

For the three months ended March 31, 2017, we had foreign exchange gains of $1.8 million compared with foreign exchange losses of $0.8 million in the corresponding period in 2016. Under U.S. GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation was the main source of the foreign exchange gains and losses. The following table presents the change in the U.S. dollar against the Colombian peso for the three months ended March 31, 2017, and 2016:

	Three Months Ended March 31,	
	2017	**2016**
Change in the U.S. dollar against the Colombian peso	**weakened by 4%**	strengthened by 4%

Financial Instrument Gains and Losses

The following table presents the nature of our financial instruments gains and losses for the three months ended March 31, 2017, and 2016:

	Three Months Ended March 31,	
(Thousands of U.S. Dollars)	**2017**	**2016**
Commodity price derivative gain	**$ (4,703)**	$ —
Foreign currency derivatives gain	**(736)**	—
Trading securities loss	**—**	845
	$ (5,439)	$ 845

Gain on Acquisition

During the fourth quarter of 2016, we obtained further information about the acquisition date fair value of the proved and unproved properties of Petroamerica and determined that the fair values were $12.5 million lower and $2.2 million higher, respectively, than previously estimated. This resulted in a $10.8 million decrease in the gain on acquisition, and a $0.5 million increase in the acquisition date deferred tax liability. In accordance with GAAP, these changes were accounted for in the fourth quarter of 2016 without retrospective revision of prior periods. The reduction in the acquisition date fair value of proved properties would have resulted in a $11.4 million, net of income tax expense, reduction in the net loss for the three months ended March 31, 2016, as a result of lower Colombian ceiling test impairment losses.

Income Tax Expense and Recovery

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	2016
Income (loss) before income tax	**$ 31,567**	$ (70,145)
Current income tax expense	**$ 7,417**	$ 2,023
Deferred income tax expense (recovery)	**11,379**	(27,136)
Total income tax expense (recovery)	**$ 18,796**	$ (25,113)
Effective tax rate	**60%**	36%
Deferred income tax recovery related to Colombia ceiling test impairment	**$ —**	$ 22,400

Current income tax expense was higher in the three months ended March 31, 2017, compared with the corresponding period in 2016 as a result of higher taxable income in Colombia. The deferred income tax expense of $11.4 million for the three month ended March 31, 2017, was primarily due to excess tax depreciation compared with accounting depreciation in Colombia. The deferred income tax recovery in corresponding period in 2016 of $27.1 million included $22.4 million associated with ceiling test impairment losses in Colombia. In 2016, the income tax recovery associated with impairment losses in Peru and Brazil was offset by a full valuation allowance.

The effective tax rate was 60% in the three months ended March 31, 2017, compared with 36% in the corresponding period in 2016. The change in the effective tax rate for the three months ended March 31, 2017, was primarily due to an increase in the impact of foreign taxes, other permanent differences, foreign currency translation adjustments, an increase in the valuation allowance, and non-deductible third-party royalty in Colombia, partially offset by other local taxes.

For the three months ended March 31, 2017, the difference between the effective tax rate of 60% and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance, which was largely attributable to losses incurred in the United States, Brazil and Colombia, as well as the impact of a non-deductible third-party royalty in Colombia, foreign taxes, local taxes, and stock based compensation. These items were partially offset by foreign currency translation adjustments and other permanent differences.

For the three months ended March 31, 2016, the difference between the effective tax rate of 36% and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance, other local taxes and a non-deductible third party royalty in Colombia, partially offset by other permanent differences, the impact of foreign taxes and foreign currency translation.

Funds flow from operations (a non-GAAP liquidity measure)

For the three months ended March 31, 2017, funds flow from operations increased by 289% to $45.0 million compared with the comparative period in 2016. Funds flow from operations for the three months ended March 31, 2017, is reconciled to the comparative period in 2016 and the prior quarter in the table below:

(Thousands of U.S. Dollars)	First Quarter 2017 Compared with Fourth Quarter 2016	% change	First Quarter 2017 Compared with First Quarter 2016	% change
Funds flow from operations for the comparative period	$ 36,186		$ 11,563	
Increase (decrease) due to:				
Prices	10,685		39,276	
Sales volumes	(7,640)		(2,020)	
Expenses:				
Operating	535		(4,870)	
Transportation	516		5,386	
Cash G&A and RSU settlements, excluding stock-based compensation expense	2,842		(1,565)	
Transaction	—		1,237	
Severance	20		1,018	
Interest, net of amortization of debt issuance costs	935		(2,111)	
Realized foreign exchange gains	365		(2)	
Settlement of financial instruments	768		724	
Current taxes	1,025		(5,394)	
Equity tax	(1,179)		1,827	
Other	(32)		(43)	
Net change in funds flow from comparative period	8,840		33,463	
Funds flow from operations for the current period	**$ 45,026**	**24%**	**$ 45,026**	**289%**

2017 Capital Program

In December 2016, we announced our 2017 capital budget. We expect the following ranges for our 2017 capital budget:

	Number of Wells (Gross)	Number of Wells (Net)	2017 Capital Budget ($ million)
Colombia			
Development	15-19	13-14	$100-140
Exploration	8-11	7-9	85-95
Total Colombia	23-30	20-23	$185-235
Brazil	—	—	8
Peru	—	—	6
Corporate	—	—	1
Total company	23-30	20-23	$200-250

Colombia remains our primary focus and, based on the midpoint of the guidance, is expected to represent approximately 93% of the 2017 capital program. Based on the midpoint of the guidance, the capital budget is forecasted to be approximately 57% directed to development and 43% to exploration. Between 15% and 20% of the 2017 capital program is expected to be directed to facilities. A large portion of this investment is expected to be dedicated to facilities expansion at the Acordionero Field in order to increase oil production capacity to 15,000 BOEPD by 2017 year-end. The 2017 capital program assumes up to six drilling rigs being active during the year.

We expect to finance our 2017 capital program through cash flows from operations and available capacity under our credit facility, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions.

Capital expenditures during the three months ended March 31, 2017, were $46.2 million:

(Thousands of U.S. Dollars)		
Colombia	$	**42,840**
Brazil		**1,749**
Peru		**1,207**
Corporate		**364**
	$	**46,160**

The significant elements of our first quarter 2017 capital program in were:

Colombia

- On the Chaza Block (100% working interest ("WI"), operated), we drilled the Costayaco-28 horizontal development well and completed the Costayaco-23 injector well for injection purposes. We are currently completing the Costayaco-28 development well. We also commenced workovers on the Moqueta-18 and Moqueta-19 wells.

- On the Putumayo-7 Block (100% WI, operated), we continued work on the Alpha-1 exploration well and drilled the Confianza-1 exploration well and successfully tested two new zones - U Sand and A Limestone.

- On the Midas Block (100% WI, operated), we drilled the Acordionero-8i well as a planned water injector and tested a new oil zone in the Lisama D and drilled the Acordionero-9 and 10 development wells.

- On the Suroriente Block (15.8% WI, non-operated), we drilled the Cohembi-19 development well.

- On the El Porton Block (100% WI, operated), we continued pre-drilling activities for the Prosperidad-1 exploration well.

- We continued facilities work at the Moqueta and Acordionero Fields.

Brazil and Peru

In Brazil, we continued facility improvements on Block 155 primarily installing a water injection facility (100% WI, operated).

In Peru, we continued work on a revised development plan for Block 95, activities relating to maintaining tangible asset integrity and security of our five blocks in Peru (95, 107 and 133, 123 and 129) and to forward environmental approvals on Blocks 107 and 133 (100% WI, operated).

Liquidity and Capital Resources

	As at				
(Thousands of U.S. Dollars)		**March 31, 2017**	**% Change**		**December 31, 2016**
Cash and Cash Equivalents	$	**26,716**	6	$	25,175
Current Restricted Cash and Cash Equivalents	$	**7,663**	(8)	$	8,322
Revolving Credit Facility	$	**85,000**	(6)	$	90,000
Convertible Senior Notes	$	**115,000**	—	$	115,000

We believe that our capital resources, including cash on hand, cash generated from operations and available capacity on our credit facility, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2017, given current oil price trends and production levels. In accordance with our investment policy, available cash balances are held in our primary cash management bank in interest earning current accounts or may be invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At March 31, 2017, we had a revolving credit facility with a syndicate of lenders with a borrowing base of $250 million readily available. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. As a result of the semi-annual redetermination of the committed borrowing base under our revolving credit facility, subject to documentation, we expect the committed borrowing base to be increased from $250 million to $300 million readily available. The next re-determination of the borrowing base is due to occur no later than November 2017. Borrowings under the revolving credit facility will mature on September 18, 2018.

Under the terms of our credit facility, we are required to maintain compliance with certain financial and operating covenants which include: the maintenance of a ratio of debt, including letters of credit, to net income plus interest, taxes, depreciation, depletion, amortization, exploration expenses and all non-cash charges minus all non-cash income ("EBITDAX") not to exceed 4.00 to 1.0; the maintenance of a ratio of senior secured obligations to EBITDAX not to exceed 3.00 to 1.00; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5 to 1.0. As at March 31, 2017, we were in compliance with all financial and operating covenants in our credit agreement. Under the terms of the credit facility, we are limited in our ability to pay any dividends to our shareholders without bank approval.

The Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted.

Cash and Cash Equivalents Held Outside of Canada and the United States

At March 31, 2017, 86% of our cash and cash equivalents were held by subsidiaries and partnerships outside of Canada and the United States. This cash was generally not available to fund domestic or head office operations unless funds were repatriated. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The government in Brazil requires us to register funds that enter and exit the country with its central bank. In Brazil and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in a special exchange regime, and we receive revenue in U.S. dollars offshore. We may also pay invoices denominated in U.S. dollars for our Colombian business from these U.S. dollars received offshore. In Peru, expenditures may be paid in local currency or U.S. dollars.

Derivative Positions

At March 31, 2017, we had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold Put ($/bbl)	Purchased Put ($/bbl)	Sold Call ($/bbl)
Collar: June 1, 2016 to May 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65

At March 31, 2017, we had outstanding foreign currency derivative positions as follows:

Period and type of instrument	Amount Hedged (Millions COP)	U.S. Dollar Equivalent of Amount Hedged [1] (Thousands of U.S. Dollars)	Reference	Purchased Call (COP)	Sold Put (COP Weighted Average Rate)
Collar: April 1, 2017 to May 31, 2017	22,697	7,881	COP	3,100	3,340

[1] At March 31, 2017 foreign exchange rate.

Cash Flows

The following table presents our primary sources and uses of cash and cash equivalents for the periods presented:

	Three Months Ended March 31,	
	2017	**2016**
Sources of cash and cash equivalents:		
Funds flow from operating activities	**$ 45,026**	$ 11,563
Net changes in assets and liabilities from operating activities	**4,930**	—
Proceeds from bank debt, net of issuance costs	**18,471**	—
Deposit received for Brazil Divestiture	**3,500**	—
Changes in non-cash investing working capital	**—**	50
Foreign exchange gain on cash, cash equivalents and restricted cash and cash equivalents	**474**	1,154
Proceeds from issuance of shares	**—**	1,198
	72,401	13,965
Uses of cash and cash equivalents:		
Additions to property, plant and equipment	**(46,160)**	(26,180)
Repayment of debt	**(23,000)**	—
Changes in non-cash investing working capital	**(1,797)**	—
Acquisition of PetroAmerica, net of cash acquired	**—**	(40,201)
Additions to property, plant and equipment - acquisition of PetroGranada Colombia Limited	**—**	(19,388)
Net changes in assets and liabilities from operating activities	**—**	(647)
Settlement of asset retirement obligations	**(13)**	(104)
	(70,970)	(86,520)
Net increase (decrease) in cash and cash equivalents	**$ 1,431**	$ (72,555)

Cash provided by operating activities in the three months ended March 31, 2017, was primarily affected by higher funds flow from operations (see funds flow from operations reconciliation under the heading 'Consolidated Results of Operations' above) and an $4.9 million change in assets and liabilities from operating activities.

One of the primary sources of variability in our cash flows from operating activities is the fluctuation in oil prices, the impact of which we partially mitigate by entering into commodity derivatives. Sales volume changes and costs related to operations and debt service also impact cash flow. Our cash flows from operating activities are also impacted by foreign currency exchange rate changes, the impact of which we partially mitigate by entering into foreign currency derivatives.

Off-Balance Sheet Arrangements

As at March 31, 2017, we had no off-balance sheet arrangements.

Contractual Obligations

During the three months ended March 31, 2017, we repaid a net amount of $4.5 million of the balance outstanding on our revolving credit facility. Except as noted above, as at March 31, 2017, there were no other material changes to our contractual obligations outside of the ordinary course of business from those as at December 31, 2016.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2016 Annual Report on Form 10-K, filed with the SEC on March 1, 2017, and have not changed materially since the filing of that document, other than as follows:

Full Cost Method of Accounting and Impairments of Oil and Gas Properties

In the three months ended March 31, 2017, we had no ceiling test impairment losses in our Colombia and Brazil cost centers. We used an average Brent price of $49.33 per bbl for the purposes of the March 31, 2017, ceiling test calculations (December 31 2016 - $42.92; March 31, 2016 - $48.79; December 31, 2015 - $54.08).

Holding all factors constant other than benchmark oil prices, it is reasonably likely that we will not experience ceiling test impairment losses in our Brazil or Colombia cost centers in the second quarter of 2017. It is difficult to predict with reasonable certainty the amount of expected future impairment losses given the many factors impacting the asset base and the cash flows used in the prescribed U.S. GAAP ceiling test calculation. These factors include, but are not limited to, future commodity pricing, royalty rates in different pricing environments, operating costs and negotiated savings, foreign exchange rates, capital expenditures timing and negotiated savings, production and its impact on depletion and cost base, upward or downward reserve revisions as a result of ongoing exploration and development activity, and tax attributes.

Subject to these factors and inherent limitations, we do not believe that ceiling test impairment losses will be experienced in the second quarter of 2017. The calculation of the impact of higher commodity prices on our estimated ceiling test calculation was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of benchmark oil prices. Therefore, this calculation strictly isolates the impact of commodity prices on the prescribed GAAP ceiling test. This calculation was based on pro forma Brent oil price of $51.70 per bbl for the year ended June 30, 2017. These pro forma oil prices were calculated using a 12-month unweighted arithmetic average of oil prices, and included the oil prices on the first day of the month for the ten months ended April 30, 2017, and, for the two months ended June 30, 2017, estimated oil prices for the second quarter of 2017 using the forward price curve forecast from Bloomberg dated March 31, 2017.

As noted above, actual cash flows may be materially affected by other factors. For example, in Colombia, cash royalties are levied at lower rates in low oil price environments and foreign exchange rates can materially impact the deferred tax component of the asset base, operating costs, and the income tax calculation. In Brazil, foreign exchange rates can materially impact operating costs and the income tax calculation.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

Commodity price risk

Our principal market risk relates to oil prices. Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand imbalance and many other market factors outside of our control. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to West Texas Intermediate ("WTI") or Brent and adjusted for quality each month.

We have entered into commodity price derivative contracts to manage the variability in cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending.

Foreign currency risk

Foreign currency risk is a factor for our company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. Our reporting currency is U.S. dollars and 100% of our revenues are related to the U.S. dollar price of Brent or WTI oil. In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars or are based on U.S. dollar prices. In Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of our capital expenditures within Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. In Peru, capital expenditures are based on U.S. dollar prices and may be paid in local currency or U.S. dollars. The majority of income and value added taxes and G&A expenses in all locations are in local currency. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency.

We have entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. We are exposed to interest rate fluctuations on our revolving credit facility, which bears floating rates of interest. At March 31, 2017, our outstanding our revolving credit facility was $85.0 million (December 31, 2016 - $90.0 million), which had a weighted-average interest rate of approximately 3.2%. A 10% change in LIBOR would not materially impact our interest expense on debt outstanding at March 31, 2017.

Further information

See Note 10 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for further information regarding our derivative contracts, including the notional amounts and call and put prices by expected (contractual) maturity dates. Expected cash flows from the derivatives equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. We do not hold any of these derivative contracts for trading purposes.

Item 4. *Controls and Procedures*

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as at March 31, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II - Other Information

Item 1. ***Legal Proceedings***

See Note 9 in the Notes to the Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated herein by reference, for material developments with respect to matters previously reported in our Annual Report on Form 10-K for the year ended December 31, 2016, and material matters that have arisen since the filing of such report.

Item 1A. ***Risk Factors***

See Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the fiscal year ended December 31, 2016. The risks facing our company have not changed materially from those set forth in Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

Item 6. ***Exhibits***

The exhibits required to be filed by Item 6 are set forth in the Exhibit Index accompanying this Quarterly Report.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

GRAN TIERRA ENERGY INC.

Date: May 3, 2017	/s/ Gary Guidry
	By: Gary Guidry President and Chief Executive Officer (Principal Executive Officer)
Date: May 3, 2017	/s/ Ryan Ellson
	By: Ryan Ellson Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1+	Arrangement Agreement, dated November 12, 2015, between Gran Tierra Energy Inc. and Petroamerica Oil Corp.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 18, 2015 (SEC File No. 001-34018).
2.2	Plan of Conversion, dated October 31, 2016.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.1	Certificate of Incorporation.	Incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.2	Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
4.1	Reference is made to Exhibits 3.1 to 3.2.	
4.2	Details of the Goldstrike Special Voting Share.	Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.3	Goldstrike Exchangeable Share Provisions.	Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005 and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.4	Provisions Attaching to the GTE–Solana Exchangeable Shares.	Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the SEC on October 14, 2008 (SEC File No. 001-34018).
4.5	Indenture related to the 5.00% Convertible Senior Notes due 2021, dated as of April 6, 2016, between Gran Tierra Energy Inc. and U.S. Bank National Association	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.6	Form of 5.00% Convertible Senior Notes due 2021	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.7	Subscription Receipt Agreement, dated July 8, 2016, by and between Gran Tierra Energy Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
4.8	Form of Registration Rights Agreement.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
10.1	Fifth Amendment to Credit Agreement, dated as of February 13, 2017, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., The Bank of Nova Scotia, and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on February 13, 2017 (SEC File No. 001-34018).
12.1	Statement re: Computation of Ratio of Earnings to Fixed Charges	Filed herewith.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.

31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	Filed herewith.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002	Furnished herewith.

101.INS XBRL Instance Document
101.SCH XBRL Taxonomy Extension Schema Document
101.CAL XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF XBRL Taxonomy Extension Definition Linkbase Document
101.LAB XBRL Taxonomy Extension Label Linkbase Document
101.PRE XBRL Taxonomy Extension Presentation Linkbase Document

+ Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. Gran Tierra undertakes to furnish supplemental copies of any of the omitted schedules upon request by the SEC.