GRAN TIERRA ENERGY INC.
Form 10-Q
May 03, 2017

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
(Mark One)

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2017

or

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________

Commission file number 001-34018

GRAN TIERRA ENERGY INC.
(Exact name of registrant as specified in its charter)

Delaware	98-0479924
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

900, 520 - 3 Avenue SW
Calgary, Alberta Canada T2P 0R3
(Address of principal executive offices, including zip code)
(403) 265-3221
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).
Yes ý No o
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o
	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 7(a)(2)(B) of the Securities Act. o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No ý

On May 1, 2017, the following number of shares of the registrant's capital stock were outstanding: 390,818,790 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 3,387,302 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 4,800,992 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Quarterly Period Ended March 31, 2017

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words “believe”, “expect”, “anticipate”, “intend”, “estimate” “project”, “target”, “goal”, “plan”, “objective”, “should”, or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part II, Item 1A “Risk Factors” in our Quarterly Reports on Form 10-Q and in Part I, Item 1A “Risk Factors” in our 2016 Annual Report on Form 10-K. The information included herein is given as of the filing date of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission (“SEC”) and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	BOE	barrels of oil equivalent
Mbbl	thousand barrels	BOEPD	barrels of oil equivalent per day
Mcf	thousand cubic feet	bopd	barrels of oil per day
NAR	net after royalty		

Sales volumes represent production NAR adjusted for inventory changes. Our oil and gas reserves are reported NAR. Our production is also reported NAR, except as otherwise specifically noted as "working interest production before royalties." Natural gas liquids ("NGLs") volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

PART I - Financial Information

Item 1. Financial Statements

Gran Tierra Energy Inc.
Condensed Consolidated Statements of Operations (Unaudited)
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

	Three Months Ended March 31,	
	2017	2016
OIL AND NATURAL GAS SALES (NOTE 3)	$94,659	$ 57,403
EXPENSES		
Operating	23,937	19,067
Transportation	6,942	12,328
Depletion, depreciation and accretion (Note 3)	26,593	36,912
Asset impairment (Notes 3 and 4)	283	56,898
General and administrative (Note 3)	8,712	7,049
Transaction	—	1,237
Severance	—	1,018
Equity tax	1,224	3,051
Foreign exchange (gain) loss	(1,847)	785
Financial instruments (gain) loss (Note 10)	(5,439)	845
Interest expense (Note 5)	3,095	519
	63,500	139,709
GAIN ON ACQUISITION	—	11,712
INTEREST INCOME	408	449
INCOME (LOSS) BEFORE INCOME TAXES (NOTE 3)	31,567	(70,145)
INCOME TAX (EXPENSE) RECOVERY		
Current	(7,417)	(2,023)
Deferred	(11,379)	27,136
	(18,796)	25,113
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	$12,771	$ (45,032)
NET INCOME (LOSS) PER SHARE - BASIC AND DILUTED	$0.03	$ (0.15)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	399,007,086	293,812,226
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	399,046,114	293,812,226

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Condensed Consolidated Balance Sheets (Unaudited)
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

	March 31, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents (Note 11)	$26,716	$25,175
Restricted cash and cash equivalents (Notes 7 and 11)	7,663	8,322
Accounts receivable	46,912	45,698
Derivatives (Note 10)	1,425	578
Inventory (Note 4)	7,285	7,766
Taxes receivable	23,284	26,393
Prepaid taxes (Note 2)	—	12,271
Other prepaids	4,404	5,482
Total Current Assets	117,689	131,685
Oil and Gas Properties (using the full cost method of accounting)		
Proved	460,937	412,319
Unproved	620,045	647,774
Total Oil and Gas Properties	1,080,982	1,060,093
Other capital assets	6,314	6,516
Total Property, Plant and Equipment (Notes 3 and 4)	1,087,296	1,066,609
Other Long-Term Assets		
Deferred tax assets (Note 2)	100,260	1,611
Prepaid taxes (Note 2)	—	41,784
Other long-term assets (Note 11)	24,467	23,626
Goodwill (Note 3)	102,581	102,581
Total Other Long-Term Assets	227,308	169,602
Total Assets (Note 3)	$1,432,293	$1,367,896
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	$112,414	$107,051
Derivatives (Note 10)	—	3,824
Taxes payable (Note 2)	38,210	38,939
Asset retirement obligation (Note 7)	1,214	5,215
Total Current Liabilities	151,838	155,029
Long-Term Liabilities		
Long-term debt (Notes 5 and 10)	193,159	197,083
Deferred tax liabilities (Note 2)	36,061	107,230
Asset retirement obligation (Note 7)	42,960	38,142
Other long-term liabilities	11,332	11,425
Total Long-Term Liabilities	283,512	353,880
Contingencies (Note 9)		

Shareholders’ Equity		
Common Stock (Note 6) (390,815,190 and 390,807,194 shares of Common Stock and 8,191,894 and 8,199,894 exchangeable shares, par value $0.001 per share, issued and outstanding as at March 31, 2017, and December 31, 2016, respectively)	10,303	10,303
Additional paid in capital	1,343,365	1,342,656
Deficit	(356,725)	(493,972)
Total Shareholders’ Equity	996,943	858,987
Total Liabilities and Shareholders’ Equity	$1,432,293	$1,367,896

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Condensed Consolidated Statements of Cash Flows (Unaudited)
(Thousands of U.S. Dollars)

	Three Months Ended March 31,	
	2017	2016
Operating Activities		
Net income (loss)	$12,771	$(45,032)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 3)	26,593	36,912
Asset impairment (Notes 3 and 4)	283	56,898
Deferred tax expense (recovery)	11,379	(27,136)
Stock-based compensation (Note 6)	1,203	1,460
Amortization of debt issuance costs (Note 5)	605	140
Cash settlement of restricted share units	(318)	(673)
Unrealized foreign exchange gain	(2,819)	(183)
Financial instruments (gain) loss (Note 10)	(5,439)	845
Cash settlement of financial instruments (Note 10)	768	44
Cash settlement of asset retirement obligation (Note 7)	(13)	(104)
Gain on acquisition	—	(11,712)
Net change in assets and liabilities from operating activities (Note 11)	4,930	(647)
Net cash provided by operating activities	49,943	10,812
Investing Activities		
Additions to property, plant and equipment, excluding corporate acquisition (Note 3)	(46,160)	(26,180)
Additions to property, plant and equipment - acquisition of PetroGranada Colombia Limited	—	(19,388)
Deposit received for Brazil Divestiture (Note 1)	3,500	—
Cash paid for business combinations, net of cash acquired	—	(40,201)
Changes in non-cash investing working capital	(1,797)	50
Net cash used in investing activities	(44,457)	(85,719)
Financing Activities		
Proceeds from bank debt, net of issuance costs (Note 5)	18,471	—
Repayment of bank debt (Note 5)	(23,000)	—
Proceeds from issuance of shares of Common Stock, net of issuance costs	—	1,198
Net cash (used in) provided by financing activities	(4,529)	1,198
Foreign exchange gain on cash, cash equivalents and restricted cash and cash equivalents	474	1,154
Net increase (decrease) in cash, cash equivalents and restricted cash and cash equivalents	1,431	(72,555)
Cash, cash equivalents and restricted cash and cash equivalents, beginning of period (Note 11)	43,267	148,751
Cash, cash equivalents and restricted cash and cash equivalents, end of period (Note 11)	$44,698	$76,196

Supplemental cash flow disclosures (Note 11)

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Condensed Consolidated Statements of Shareholders' Equity (Unaudited)
(Thousands of U.S. Dollars)

	Three Months Ended March 31, 2017	Year Ended December 31, 2016
Share Capital		
Balance, beginning of period	$10,303	$10,186
Issuance of Common Stock (Note 6)	—	117
Balance, end of period	10,303	10,303
Additional Paid in Capital		
Balance, beginning of period	1,342,656	1,019,863
Issuance of Common Stock, net of share issuance costs (Note 6)	—	314,425
Exercise of stock options (Note 6)	—	5,347
Stock-based compensation (Note 6)	709	3,021
Balance, end of period	1,343,365	1,342,656
Deficit		
Balance, beginning of period	(493,972)	(28,407)
Net income (loss)	12,771	(465,565)
Cumulative adjustment for accounting change related to tax reorganizations (Note 2)	124,476	—
Balance, end of period	(356,725)	(493,972)
Total Shareholders' Equity	$996,943	$858,987

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Condensed Consolidated Financial Statements (Unaudited)
(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the “Company” or “Gran Tierra”), is a publicly traded company focused on oil and natural gas exploration and production in Colombia. The Company also has business activities in Peru and Brazil.

On February, 6, 2017, the Company announced that a purchase and sale agreement (the "Agreement") had been executed by a third party ("Purchaser") to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (the "Brazil Divestiture"). Upon completion of the Brazil Divestiture, the Purchaser will acquire all of Gran Tierra's assets and certain liabilities in Brazil, including its 100% working interest in the Tiê Field and all of Gran Tierra's interest in exploration rights and obligations held pursuant to concession agreements granted by the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis of Brazil ("ANP").

The completion of the Brazil Divestiture is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP. The consideration to be received by Gran Tierra on the completion of the Brazil Divestiture is $35 million, subject to adjustments, plus the assumption by the Purchaser of certain existing and potential liabilities of Gran Tierra's Brazil business unit. Pursuant to the Agreement, the Purchaser paid a deposit of $3.5 million on February 7, 2017, which is not refundable in the event the Purchaser is not successful in obtaining financing to complete the Brazil Divestiture. The economic effective date of the transaction would be on or before August 1, 2017, and Gran Tierra will continue to operate its Brazil business unit until the completion of the Brazil Divestiture.

2. Significant Accounting Policies

These interim unaudited condensed consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”). The information furnished herein reflects all normal recurring adjustments that are, in the opinion of management, necessary for the fair presentation of results for the interim periods.

The note disclosure requirements of annual consolidated financial statements provide additional disclosures to that required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements as at and for the year ended December 31, 2016, included in the Company’s 2016 Annual Report on Form 10-K, filed with the SEC on March 1, 2017.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2016 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as noted below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

Recently Adopted Accounting Pronouncements

Simplifying the Measurement of Inventory

In July 2015, the FASB issued ASU 2015-11, “Simplifying the Measurement of Inventory". The ASU provides guidance for the subsequent measurement of inventory and requires that inventory that is measured using average cost be measured at the lower of cost and net realizable value. Net realizable value is the estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The implementation of this update did not materially impact the Company’s consolidated financial position, results of operations or cash flows or disclosure.

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting". This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company elected to continue to estimate the total number of awards for which the requisite service period will not be rendered. The implementation of this update did not impact the Company’s consolidated financial position, results of operations or cash flows or disclosure.

Income Taxes - Intra-Entity Transfers of Assets Other than Inventory

At December 31, 2016, GAAP prohibited the recognition of current and deferred income taxes for intra-entity transfers until an asset leaves the consolidated group, therefore, the current income tax effect of tax reorganizations completed in 2016 was deferred and recognized as prepaid income taxes. At December 31, 2016, the Company's balance sheet included $54.1 million of prepaid income taxes, $12.3 million in current prepaid taxes and $41.8 million in long-term prepaid taxes, and $37.5 million of current income taxes payable relating to tax reorganizations completed in 2016.

In October 2016, the FASB issued ASU 2016-16, "Intra-Entity Transfers of Assets Other than Inventory." This ASU requires companies to recognize the income tax effects of intercompany sales or transfers of assets, other than inventory, in the income statement as income tax expense or benefit in the period the sale or transfer occurs. This ASU is effective for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption was permitted as of the beginning of an annual reporting period. The ASU is required to be applied on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings in the period of adoption. The Company early adopted this ASU on January 1, 2017, and in the three months ending March 31, 2017, wrote off the income tax effects that had been deferred from past intercompany transactions to opening deficit. Prepaid tax of $54.1 million and deferred tax assets of $178.6 million were recorded directly to opening deficit at January 1, 2017. Deferred tax assets recorded upon adoption were assessed for realizability under ASC 740, and, valuation allowances were recognized on those deferred tax assets as necessary on the date of adoption. The adoption of ASU 2016-16 did not have any effect on the Company’s cash flows.

Restricted Cash and Cash Equivalents

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash". ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. The ASU was adopted on a retrospective basis to each period presented. The implementation of this ASU did not impact the Company's consolidated financial position or results of operations, and did not have a material impact on net cash used in investing activities for the three months ended March 31, 2017, or 2016.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, "Clarifying the Definition of a Business". ASU 2017-01 narrows the definition of a business and provides a framework that gives entities a basis for making reasonable judgments about whether a transaction involves an asset or a business. ASU 2017-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption was permitted and the Company adopted this ASU on January 1, 2017. The Company now applies an initial screen for determining whether a transaction involves an asset or a business. When substantially all of the fair value of the gross assets acquired is concentrated in a single identified asset, or group of similar identifiable assets, the set will not be a business and no goodwill or gain on acquisition will be recognized. If the screen is not met, a set cannot be considered a business unless it includes an input and a substantive process that together significantly contribute to the ability to create an output.

Simplifying the Test for Goodwill Impairment

In January 2017, the FASB issued ASU 2017-04, "Simplifying the Test for Goodwill Impairment". ASU 2017-04 eliminates step 2 of the goodwill impairment test. An entity no longer will determine goodwill impairment by calculating the implied fair value of goodwill by assigning the fair value of a reporting unit to all of its assets and liabilities as if that reporting unit had been acquired in a business combination. A goodwill impairment will now be the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. ASU 2017-04 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2019. Early adoption is permitted. At December 31, 2016, the Company performed a qualitative assessment of goodwill and, based on this assessment, no impairment of goodwill was identified. The Company did not have to perform step 2 of the goodwill impairment test.

3. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company’s reportable segments are Colombia, Peru and Brazil based on geographic organization. The All Other category represents the Company’s corporate activities. The Company evaluates reportable segment performance based on income or loss before income taxes. On February, 6, 2017, the Company announced that a purchase and sale agreement had been executed by the Purchaser to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (Note 1). The completion of the sale is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP.

The following tables present information on the Company’s reportable segments and other activities:

	Three Months Ended March 31, 2017				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$90,464	$ —	$4,195	$ —	$94,659
Depletion, depreciation and accretion	24,935	226	1,213	219	26,593
Asset impairment	—	283	—	—	283
General and administrative expenses	4,832	355	305	3,220	8,712
Income (loss) before income taxes	37,144	(513)	1,520	(6,584)	31,567
Segment capital expenditures	42,840	1,207	1,749	364	46,160

	Three Months Ended March 31, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$56,300	$ —	$1,103	$ —	$57,403
Depletion, depreciation and accretion	35,736	141	718	317	36,912
Asset impairment	55,232	416	1,250	—	56,898
General and administrative expenses	3,265	409	292	3,083	7,049
(Loss) income before income taxes	(72,721)	(712)	(1,509)	4,797	(70,145)
Segment capital expenditures	21,986	1,268	2,720	206	26,180

	As at March 31, 2017				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$958,977	$69,325	$55,810	$3,184	$1,087,296
Goodwill	102,581	—	—	—	102,581
All other assets	211,693	11,111	3,559	16,053	242,416
Total Assets	$1,273,251	$80,436	$59,369	$19,237	$1,432,293

	As at December 31, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$939,947	$68,428	$55,196	$3,038	$1,066,609
Goodwill	102,581	—	—	—	102,581
All other assets	177,393	10,848	1,619	8,846	198,706
Total Assets	$1,219,921	$79,276	$56,815	$11,884	$1,367,896

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4. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at March 31, 2017	As at December 31, 2016
Oil and natural gas properties		
Proved	$2,725,784	$2,652,171
Unproved	620,045	647,774
	3,345,829	3,299,945
Other	29,744	29,445
	3,375,573	3,329,390
Accumulated depletion, depreciation and impairment	(2,288,277)	(2,262,781)
	$1,087,296	$1,066,609

Asset impairment for the three months ended March 31, 2017, and 2016 was as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	2016
Impairment of oil and gas properties	$283	$56,234
Impairment of inventory	—	664
	$283	$56,898

In the three months ended March 31, 2017 and 2016, the Company recorded impairment losses in its Peru cost center of $0.3 million and $0.4 million, respectively. In the three months ended March 31, 2017, the Company had no ceiling test impairment losses in its Colombia and Brazil cost centers. In the three months ended March 31, 2016, the Company recorded ceiling test impairment losses of $54.6 million and $1.3 million, respectively, in its Colombia and Brazil cost centers, as a result of low realized oil prices.

The Company follows the full cost method of accounting for its 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 the Company's reserves. In accordance with GAAP, Gran Tierra 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).

Inventory

At March 31, 2017, oil and supplies inventories were $5.5 million and $1.8 million, respectively (December 31, 2016 - $6.0 million and $1.8 million, respectively). At March 31, 2017, the Company had 185 Mbbl of oil inventory

(December 31, 2016 - 208 Mbbl). In the three months ended March 31, 2017, the Company recorded oil inventory impairment of $nil (three months ended March 31, 2016 - $0.7 million) related to lower oil prices.

5. Debt and Debt Issuance Costs

The Company's debt at March 31, 2017, and December 31, 2016, was as follows:

(Thousands of U.S. Dollars)	As at March 31, 2017	As at December 31, 2016
Convertible senior notes	$115,000	$115,000
Revolving credit facility	85,000	90,000
Unamortized debt issuance costs	(6,841)	(7,917)
Long-term debt	$193,159	$197,083

The following table presents total interest expense recognized in the accompanying interim unaudited condensed consolidated statements of operations:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	2016
Contractual interest and other financing expenses	$2,490	$379
Amortization of debt issuance costs	605	140
	$3,095	$519

6. Share Capital

The Company’s authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as Common Stock, par value $0.001 per share, 25 million are designated as Preferred Stock, par value $0.001 per share, one share is designated as Special A Voting Stock, par value $0.001 per share, and one share is designated as Special B Voting Stock, par value $0.001 per share.

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.
Balance, December 31, 2016	390,807,194	4,812,592	3,387,302
Exchange of exchangeable shares	8,000	(8,000)	—
Shares canceled	(4)	—	—
Balance, March 31, 2017	390,815,190	4,804,592	3,387,302

Net Income (Loss) per Share

Basic net income (loss) per share is calculated by dividing net income (loss) attributable to common shareholders by the weighted average number of shares of Common Stock and exchangeable shares issued and outstanding during each period. Diluted net income (loss) per share is calculated by adjusting the weighted average number of shares of Common Stock and exchangeable shares outstanding for the dilutive effect, if any, of share equivalents. The Company uses the treasury stock method to determine the dilutive effect. This method assumes that all Common Stock equivalents have been exercised at the beginning of the period (or at the time of issuance, if later), and that the funds obtained thereby were used to purchase shares of Common Stock of the Company at the volume weighted average trading price of shares of Common Stock during the period.

Stock options and shares issuable upon conversion of the Convertible Senior Notes ("Notes") were excluded from the diluted loss per share calculation as the stock options and shares issuable upon conversion of the Notes were anti-dilutive.

Equity Compensation Awards

The following table provides information about performance stock units (“PSUs”), deferred share units (“DSUs”), restricted stock units (“RSUs”) and stock option activity for the three months ended March 31, 2017:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Stock Options	Weighted Average Exercise Price/Stock Option ($)
Balance, December 31, 2016	3,362,717	208,698	359,145	9,239,478	4.16
Granted	3,098,100	48,337	—	1,819,380	2.57
Exercised	—	—	(123,326)	—	—
Forfeited	—	—	(2,558)	(21,595)	(5.71)
Balance, March 31, 2017	6,460,817	257,035	233,261	11,037,263	3.90

Stock-based compensation expense for the three months ended March 31, 2017, and 2016, was $1.2 million and $1.5 million, respectively, and was primarily recorded in general and administrative ("G&A") expenses.

At March 31, 2017, there was $16.7 million (December 31, 2016 - $10.0 million) of unrecognized compensation cost related to unvested PSUs, RSUs and stock options which is expected to be recognized over a weighted average period of 2.2 years.

Weighted Average Shares Outstanding

	Three Months Ended March 31,	
	2017	2016
Weighted average number of common and exchangeable shares outstanding	399,007,086	293,812,226
Shares issuable pursuant to stock options	635,484	—
Shares assumed to be purchased from proceeds of stock options	(596,456)	—
Weighted average number of diluted common and exchangeable shares outstanding	399,046,114	293,812,226

For the three months ended March 31, 2017, 9,210,869 options, on a weighted average basis, (2016 - 12,667,761 options) were excluded from the diluted income (loss) per share calculation as the options were anti-dilutive.

7. Asset Retirement Obligation

Changes in the carrying amounts of the asset retirement obligation associated with the Company’s oil and natural gas properties were as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2017	Year Ended December 31, 2016
Balance, beginning of period	$ 43,357	$ 33,224
Settlements	(195)	(872)
Liabilities associated with assets sold	—	(3,257)
Liability incurred	190	2,606
Liabilities assumed in acquisition	—	15,723
Accretion	822	2,789
Revisions in estimated liability	—	(6,856)
Balance, end of period	$ 44,174	$ 43,357

Asset retirement obligation - current	$ 1,214	$ 5,215
Asset retirement obligation - long-term	42,960	38,142
	$ 44,174	$ 43,357

For the three months ended March 31, 2017, settlements included $nil cash payments with the balance in accounts payable and accrued liabilities at March 31, 2017. Revisions in estimated liabilities relate primarily to changes in estimates of asset

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retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling asset retirement obligations. At March 31, 2017, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was $12.6 million (December 31, 2016 - $12.0 million). These assets are accounted for as restricted cash and cash equivalents on the Company's interim unaudited condensed consolidated balance sheets.

8. Taxes

The Company's effective tax rate was 60% in the three months ended March 31, 2017, compared with 36% in the corresponding period in 2016. The Company's effective tax rate differed from the U.S. statutory rate of 35% primarily due
to an increase to 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.

9. Contingencies

The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH") and Gran Tierra are engaged in ongoing discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of an additional royalty (the "HPR royalty"). Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $46.4 million as at March 31, 2017. At this time no amount has been accrued in the interim unaudited condensed consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

In addition to the above, Gran Tierra has a number of other lawsuits and claims pending. Although the outcome of these other lawsuits and disputes cannot be predicted with certainty, Gran Tierra believes the resolution of these matters would not have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flows. Gran Tierra records costs as they are incurred or become probable and determinable.

Letters of credit and other credit support

At March 31, 2017, the Company had provided letters of credit and other credit support totaling $88.3 million (December 31, 2016 - $96.8 million) as security relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

10. Financial Instruments and Fair Value Measurement

Financial Instruments

At March 31, 2017, the Company’s financial instruments recognized in the balance sheet consist of: cash and cash equivalents; restricted cash and cash equivalents; accounts receivable; derivatives, accounts payable and accrued liabilities, long-term debt, PSU liability included in other long-term liabilities, and RSU liability included in accounts payable and accrued liabilities and other long-term liabilities.

Fair Value Measurement

The fair value of derivatives and RSU and PSU liabilities are being remeasured at the estimated fair value at the end of each reporting period.

The fair value of commodity price and foreign currency derivatives is estimated based on various factors, including quoted market prices in active markets and quotes from third parties. The Company also performs an internal valuation to ensure the reasonableness of third party quotes. In consideration of counterparty credit risk, the Company assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions.

The fair value of the RSU liability was estimated based on quoted market prices in an active market. The fair value of the PSU liability was estimated based on quoted market prices in an active market and an option pricing model such as the Monte Carlo simulation option-pricing models.

The fair value of derivatives, and RSU and PSU liabilities at March 31, 2017, and December 31, 2016, were as follows:

(Thousands of U.S. Dollars)	As at March 31, 2017	As at December 31, 2016
Commodity price derivative asset	$879	$ —
Foreign currency derivative asset	546	578
	$1,425	$ 578
Commodity price derivative liability	$—	$ 3,824
RSU, PSU and DSU liability	4,197	3,907
	$4,197	$ 7,731

The following table presents gains or losses on financial instruments recognized in the accompanying interim unaudited condensed consolidated statements of operations:

	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
Financial instruments (gain) loss	$(5,439)	$845

These gains and losses are presented as financial instruments gains or losses in the interim unaudited condensed consolidated statements of operations and cash flows.

Financial instruments not recorded at fair value include the Notes. At March 31, 2017, the carrying amount of the Notes was $110.1 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was $128.5 million. The fair value of long-term restricted cash and cash equivalents and the revolving credit facility approximated their carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities.

At March 31, 2017, the fair value of the derivatives was determined using Level 2 inputs and the fair value of the PSU liability was determined using Level 3 inputs.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the

Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's Notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The disclosure in the paragraph above regarding the fair value of the Company's revolving credit facility was determined using an income approach using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of the Notes was determined using Level 2 inputs based on the indicative pricing published by certain investment banks or trading levels of the Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and cash equivalents and restricted cash and cash equivalents was based on Level 1 inputs.

The Company’s non-recurring fair value measurements include asset retirement obligations. The fair value of an asset retirement obligation is measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company’s credit-adjusted risk-free interest rate. The significant level 3 inputs used to calculate such liabilities include estimates of costs to be incurred, the Company’s credit-adjusted risk-free interest rate, inflation rates and estimated dates of abandonment. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value, while the asset retirement cost is amortized over the estimated productive life of the related assets.

Commodity Price Derivatives

The Company utilizes commodity price derivatives to manage the variability in cash flows associated with the forecasted sale of its oil production, reduce commodity price risk and provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

At March 31, 2017, the Company 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

Foreign Currency Derivatives

The Company utilizes foreign currency derivatives to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("COP") denominated costs.

At March 31, 2017, the Company 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.

11. Supplemental Cash Flow Information

The following table provides a reconciliation of cash, cash equivalents and restricted cash and cash equivalents with the Company's interim unaudited condensed consolidated balance sheet that sum to the total of the same such amounts shown in the interim unaudited condensed consolidated statements of cash flows:

(Thousands of U.S. Dollars)	As at March 31,		As at December 31,	
	2017	2016	2016	2015
Cash and cash equivalents	$26,716	$51,308	$25,175	$145,342

Restricted cash and cash equivalents - current	7,663	18,474	8,322	92
Restricted cash and cash equivalents - included in other long-term assets	10,319	6,414	9,770	3,317
	$44,698	$76,196	$43,267	$148,751

Net changes in assets and liabilities from operating activities were as follows:

(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

(Thousands of U.S. Dollars)	As at 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

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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

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Consolidated Results of Operations

	Three Months Ended December 31	Three Months Ended March 31,		
	2016	2017	2016	% Change
(Thousands of U.S. Dollars)				
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

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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	First Quarter 2017

	Compared with Fourth Quarter 2016	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

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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	First Quarter 2017 Compared with First Quarter

	Quarter 2016	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

	Three Months Ended December 31	Three Months Ended March 31,		
(Thousands of U.S. Dollars)	2017	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

	Three Months Ended March 31,	
(Thousands of U.S. Dollars)	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

(Thousands of U.S. Dollars)	As at 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.