UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2017

or

☐ **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 ☒ No ☐

Indicate by check mark whether the registrant has 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 ☒ No ☐

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 ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐
	Emerging growth company ☐

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 13(a) of the Exchange Act. ☐

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

On October 31, 2017, the following number of shares of the registrant's capital stock were outstanding: 388,415,513 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 1,688,889 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 4,666,792 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 September 30, 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, as amended (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, impact of proposed or pending transactions, 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, sustained or future declines in commodity prices; potential future impairments and reductions in proved reserve quantities and value; our operations are located in South America, and unexpected problems can arise due to guerilla activity; technical difficulties and operational difficulties may arise which impact the production, transport or sale of our products; geographic, political and weather conditions can impact the production, transport or sale of our products; the risk that current global economic and credit conditions may impact oil prices and oil consumption more than we currently predict; our ability to execute its business plan; the risk that unexpected delays and difficulties in developing currently owned properties may occur; the timely receipt of regulatory or other required approvals for our operating activities; the failure of exploratory drilling to result in commercial wells; unexpected delays due to the limited availability of drilling equipment and personnel; the risk that current global economic and credit market conditions may impact oil prices and oil consumption more than we currently predict, which could cause us to further modify our strategy and capital spending program; those set out in Part I, Item 1A “Risk Factors” in our 2016 Annual Report on Form 10-K and in our other filings with the Securities and Exchange Commission (“SEC”). The information included herein is given as of the filing date of this Quarterly Report on Form 10-Q with the SEC and, except as otherwise required by the federal securities laws, we disclaim any obligation 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 September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
OIL AND NATURAL GAS SALES (NOTE 3)	**$ 103,768**	$ 68,539	**$ 294,555**	$ 197,655
EXPENSES				
Operating	**27,321**	25,638	**78,466**	62,453
Transportation	**6,038**	5,773	**19,472**	24,318
Depletion, depreciation and accretion (Note 3)	**34,492**	35,729	**92,729**	104,525
Asset impairment (Notes 3 and 4)	**787**	319,974	**1,239**	469,715
General and administrative (Note 3)	**8,651**	5,592	**26,876**	20,614
Severance	**1,164**	—	**1,164**	1,299
Transaction	**—**	6,088	**—**	7,325
Equity tax	**—**	—	**1,224**	3,053
Foreign exchange (gain) loss	**(1,271)**	(507)	**779**	1,059
Financial instruments loss (gain) (Note 10)	**1,675**	2,051	**(5,211)**	1,824
Interest expense (Note 5)	**3,989**	5,122	**10,415**	7,842
	82,846	405,460	**227,153**	704,027
LOSS ON SALE OF BRAZIL BUSINESS UNIT (NOTE 4)	**—**	—	**(9,076)**	—
GAIN ON ACQUISITION	**—**	—	**—**	11,712
INTEREST INCOME	**301**	730	**954**	1,928
INCOME (LOSS) BEFORE INCOME TAXES (NOTE 3)	**21,223**	(336,191)	**59,280**	(492,732)
INCOME TAX EXPENSE (RECOVERY)				
Current	**4,333**	3,879	**13,522**	11,680
Deferred	**13,760**	(110,451)	**36,664**	(166,202)
	18,093	(106,572)	**50,186**	(154,522)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	**$ 3,130**	$ (229,619)	**$ 9,094**	$ (338,210)
NET INCOME (LOSS) PER SHARE - BASIC AND DILUTED	**$ 0.01**	$ (0.71)	**$ 0.02**	$ (1.11)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	***394,771,194***	*321,725,379*	***397,439,007***	*304,098,944*
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	***394,774,953***	*321,725,379*	***397,450,637***	*304,098,944*

(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)

	September 30, 2017	December 31, 2016
ASSETS		
Current Assets		
Cash and cash equivalents (Note 11)	**$ 15,125**	$ 25,175
Restricted cash and cash equivalents (Notes 7 and 11)	**3,920**	8,322
Accounts receivable	**38,279**	45,698
Derivatives (Note 10)	**512**	578
Inventory (Note 4)	**6,978**	7,766
Taxes receivable	**34,879**	26,393
Prepaid taxes (Note 2)	**—**	12,271
Other prepaids	**2,194**	5,482
Total Current Assets	**101,887**	131,685
Oil and Gas Properties (using the full cost method of accounting)		
Proved	**508,981**	412,319
Unproved	**613,419**	647,774
Total Oil and Gas Properties	**1,122,400**	1,060,093
Other capital assets	**5,224**	6,516
Total Property, Plant and Equipment (Notes 3 and 4)	**1,127,624**	1,066,609
Other Long-Term Assets		
Deferred tax assets (Note 2)	**66,963**	1,611
Prepaid taxes (Note 2)	**—**	41,784
Restricted cash and cash equivalents (Notes 7 and 11)	**10,332**	9,770
Other long-term assets	**13,789**	13,856
Goodwill (Note 3)	**102,581**	102,581
Total Other Long-Term Assets	**193,665**	169,602
Total Assets (Note 3)	**$ 1,423,176**	$ 1,367,896
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	**$ 119,829**	$ 107,051
Derivatives (Note 10)	**65**	3,824
Taxes payable (Note 2)	**2,419**	38,939
Asset retirement obligation (Note 7)	**355**	5,215
Total Current Liabilities	**122,668**	155,029
Long-Term Liabilities		
Long-term debt (Notes 5 and 10)	**229,215**	197,083
Deferred tax liabilities (Note 2)	**29,368**	107,230
Asset retirement obligation (Note 7)	**43,649**	38,142
Other long-term liabilities	**13,816**	11,425
Total Long-Term Liabilities	**316,048**	353,880
Contingencies (Note 9)		
Shareholders' Equity		
Common Stock (Note 6) (386,872,530 and 390,807,194 shares of Common Stock and 7,898,664 and 8,199,894 exchangeable shares, par value $0.001 per share, issued and outstanding as at September 30, 2017, and December 31, 2016, respectively)	**10,299**	10,303
Additional paid in capital	**1,334,563**	1,342,656
Deficit	**(360,402)**	(493,972)
Total Shareholders' Equity	**984,460**	858,987
Total Liabilities and Shareholders' Equity	**$ 1,423,176**	$ 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)

	Nine Months Ended September 30,	
	2017	**2016**
Operating Activities		
Net income (loss)	**$ 9,094**	$ (338,210)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 3)	**92,729**	104,525
Asset impairment (Notes 3 and 4)	**1,239**	469,715
Deferred tax expense (recovery)	**36,664**	(166,202)
Stock-based compensation (Note 6)	**4,935**	4,380
Amortization of debt issuance costs (Note 5)	**1,868**	2,813
Cash settlement of restricted share units	**(534)**	(1,210)
Unrealized foreign exchange (gain) loss	**(304)**	2,437
Financial instruments (gain) loss (Note 10)	**(5,211)**	1,824
Cash settlement of financial instruments (Note 10)	**1,518**	438
Cash settlement of asset retirement obligation (Note 7)	**(462)**	(496)
Loss on sale of Brazil business unit (Note 4)	**9,076**	—
Gain on acquisition	**—**	(11,712)
Net change in assets and liabilities from operating activities (Note 11)	**(28,105)**	18,097
Net cash provided by operating activities	**122,507**	86,399
Investing Activities		
Additions to property, plant and equipment (Note 3)	**(175,719)**	(69,667)
Additions to property, plant and equipment - property acquisitions (Note 4)	**(30,410)**	(19,388)
Net proceeds from sale of Brazil business unit (Note 4)	**34,481**	—
Cash deposit received for letter of credit arrangements upon sale of Brazil business unit (Note 4)	**4,700**	—
Cash paid for business combinations, net of cash acquired	**—**	(457,183)
Proceeds from sale of marketable securities	**—**	788
Changes in non-cash investing working capital	**11,347**	(8,036)
Net cash used in investing activities	**(155,601)**	(553,486)
Financing Activities		
Proceeds from bank debt, net of issuance costs (Note 5)	**115,264**	220,169
Repayment of bank debt (Note 5)	**(85,000)**	(110,181)
Proceeds from issuance of shares of Common Stock, net of issuance costs	**—**	5,169
Repurchase of shares of Common Stock (Note 6)	**(10,000)**	—
Proceeds from issuance of subscription receipts, net of issuance costs	**—**	165,805
Proceeds from issuance of Convertible Senior Notes, net of issuance costs (Note 5)	**—**	109,090
Net cash provided by financing activities	**20,264**	390,052
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	**(1,060)**	(452)
Net decrease in cash, cash equivalents and restricted cash and cash equivalents	**(13,890)**	(77,487)
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)	**$ 29,377**	$ 71,264
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)

	Nine Months Ended September 30,	Year Ended December 31,
	2017	**2016**
Share Capital		
Balance, beginning of period	**$ 10,303**	$ 10,186
Issuance of Common Stock	—	117
Repurchase of Common Stock (Note 6)	**(4)**	—
Balance, end of period	**10,299**	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	—	314,425
Exercise of stock options	—	5,347
Stock-based compensation (Note 6)	**1,903**	3,021
Repurchase of Common Stock (Note 6)	**(9,996)**	—
Balance, end of period	**1,334,563**	1,342,656
Deficit		
Balance, beginning of period	**(493,972)**	(28,407)
Net income (loss)	**9,094**	(465,565)
Cumulative adjustment for accounting change related to tax reorganizations (Note 2)	**124,476**	—
Balance, end of period	**(360,402)**	(493,972)
Total Shareholders' Equity	**$ 984,460**	$ 858,987

(See notes to the condensed consolidated financial statements)

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, until June 30, 2017, had business activities in Brazil.

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 Financial Accounting Standards Board (“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 Accounting Standards Codification ("ASC") 740 "Income Taxes", 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. Early adoption was permitted. The Company early adopted this ASU on January 1, 2017, 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. For the nine months ended September 30, 2016, the net decrease in cash, cash equivalents and restricted cash and cash equivalents currently disclosed was $77.5 million, compared with the net decrease in cash and cash equivalents of $97.3 million as previously disclosed in the consolidated statement of cash flows prior to the adoption of ASU 2016-18.

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. The Company’s acquisition of the Santana and Nancy Burdine-Maxine oil and gas properties in the nine months ended September 30, 2017 was not considered a business under this ASU and therefore not allocated goodwill or gain on acquisition (Note 4).

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. 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 September 30, 2017, 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.

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. In August 2015, the FASB issued ASU 2015-14, “Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU deferred the effective date of the new revenue recognition model by one year. As a result, the guidance will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. In March 2016, the FASB issued ASU 2016-08, “Principal versus Agent Considerations (Reporting Revenue Gross versus Net)" which clarifies implementation guidance on principal versus agent considerations. In April, May and December 2016, the FASB issued ASU 2016-10, “Identifying Performance Obligations and Licensing", ASU 2016-12, “Narrow-Scope Improvements and Practical Expedients" and ASU 2016-20 "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers", respectively, which addressed implementation issues and provided technical corrections. The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings.

The Company is continuing to evaluate the impact of the ASU and currently expects that the standard will not have a material impact on the Company’s consolidated financial statements other than enhanced disclosures related to revenues from contracts with customers. The Company intends to adopt the new standard using the modified retrospective method at the date of adoption, which is expected to be January 1, 2018.

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 and Peru, based on geographic organization. Prior to the sale of the Company’s Brazil business unit effective June 30, 2017, (Note 4), Brazil was a reportable segment. The All Other category represents the Company’s corporate and Mexico activities. The Company evaluates reportable segment performance based on income or loss before income taxes.

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

(Thousands of U.S. Dollars)	Three Months Ended September 30, 2017 Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	**$ 103,768**	**$ —**	**$ —**	**$ —**	**$ 103,768**
Depletion, depreciation and accretion	**33,388**	**881**	**—**	**223**	**34,492**
Asset impairment	**—**	**176**	**—**	**611**	**787**
General and administrative expenses	**5,500**	**301**	**—**	**2,850**	**8,651**
Income (loss) before income taxes	**31,276**	**(1,405)**	**—**	**(8,648)**	**21,223**
Segment capital expenditures	**70,606**	**998**	**—**	**90**	**71,694**

(Thousands of U.S. Dollars)	Three Months Ended September 30, 2016 Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 65,944	$ —	$ 2,595	$ —	$ 68,539
Depletion, depreciation and accretion	34,156	206	1,022	345	35,729
Asset impairment	298,370	—	21,604	—	319,974
General and administrative expenses	1,921	218	218	3,235	5,592
Loss before income taxes	(299,306)	(768)	(20,977)	(15,140)	(336,191)
Segment capital expenditures	20,476	1,360	3,102	142	25,080

(Thousands of U.S. Dollars)	Nine Months Ended September 30, 2017 Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	**$ 286,137**	**$ —**	**$ 8,418**	**$ —**	**$ 294,555**
Depletion, depreciation and accretion	**88,453**	**1,350**	**2,263**	**663**	**92,729**
Asset impairment	**—**	**628**	**—**	**611**	**1,239**
General and administrative expenses	**15,561**	**974**	**743**	**9,598**	**26,876**
Income (loss) before income taxes	**90,018**	**(2,685)**	**3,369**	**(31,422)**	**59,280**
Segment capital expenditures	**168,881**	**3,207**	**2,811**	**820**	**175,719**

(Thousands of U.S. Dollars)	Nine Months Ended September 30, 2016 Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 191,515	$ —	$ 6,140	$ —	$ 197,655
Depletion, depreciation and accretion	100,350	418	2,764	993	104,525
Asset impairment	431,810	899	37,006	—	469,715
General and administrative expenses	9,614	1,014	751	9,235	20,614
Loss before income taxes	(436,863)	(2,224)	(36,523)	(17,122)	(492,732)
Segment capital expenditures	56,997	3,730	7,982	958	69,667

	As at September 30, 2017				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$ 1,054,136	$ 70,903	$ —	$ 2,585	$ 1,127,624
Goodwill	102,581	—	—	—	102,581
All other assets	176,672	11,103	—	5,196	192,971
Total Assets	$ 1,333,389	$ 82,006	$ —	$ 7,781	$ 1,423,176

	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

4. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at September 30, 2017	As at December 31, 2016
Oil and natural gas properties		
Proved	$ 2,836,263	$ 2,652,171
Unproved	613,419	647,774
	3,449,682	3,299,945
Other	27,236	29,445
	3,476,918	3,329,390
Accumulated depletion, depreciation and impairment	(2,349,294)	(2,262,781)
	$ 1,127,624	$ 1,066,609

Asset impairment for the three and nine months ended September 30, 2017, and 2016 was as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	**2017**	**2016**	**2017**	**2016**
Impairment of oil and gas properties	**$ 787**	$ 319,974	**$ 1,239**	$ 469,051
Impairment of inventory	**—**	—	**—**	664
	$ 787	$ 319,974	**$ 1,239**	$ 469,715

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, adjusted for 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 this estimate 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 $52.70 per bbl for the purposes of the September 30, 2017 ceiling test calculations (June 30, 2017 - $51.35; March 31, 2017 - $49.33; December 31, 2016 - $42.92; September 30, 2016 - $42.23; June 30, 2016 - $44.48; March 31, 2016 - $48.79; December 31, 2015 - $54.08).

Acquisition of Santana and Nancy Burdine-Maxine Blocks

On April 27, 2017, the Company acquired the Santana and Nancy-Burdine-Maxine Blocks in the Putumayo Basin for cash consideration of $30.4 million. The acquisition was accounted for as an asset acquisition with the consideration paid allocated on a relative fair value basis to the net assets acquired.

The following table shows the allocation of the cost of the acquisition based on the relative fair values of the assets and liabilities acquired:

(Thousands of U.S. Dollars)	
Cost of asset acquisition:	
Cash	$ 30,410
Allocation of Consideration Paid:	
Oil and gas properties	
Proved	$ 24,405
Unproved	8,649
	33,054
Inventory	869
Asset retirement obligation - long-term	(3,513)
	$ 30,410

Disposition of Brazil Business Unit

On June 30, 2017, the Company, through two of its indirect subsidiaries (the "Selling Subsidiaries"), completed the previously announced disposition of its assets in Brazil. Gran Tierra completed the disposition of its Brazil business unit for a purchase price of $35.0 million which, after certain interim closing adjustments, resulted in cash consideration paid to the Selling Subsidiaries of approximately $38.0 million.

At December 31, 2016, assets and liabilities of the Brazil business unit were as follows:

(Thousands of U.S. Dollars)	As at December 31, 2016
Current assets	$ 1,634
Property, plant and equipment	55,376
	$ 57,010
Current liabilities	$ (11,590)
Long-term liabilities	(2,297)
	$ (13,887)

At June 30, 2017, the net book value of the Brazil business unit was greater than the proceeds received resulting in a $9.1 million loss on sale.

Gran Tierra also received a $4.7 million cash payment from the purchaser reflecting the covenant by the purchaser to finalize the documentation and other arrangements to assume liabilities associated with letter of credit arrangements and the release of Gran Tierra from any liabilities in connection with the same, which payment will be reimbursable to the purchaser once such covenant is discharged.

Inventory

At September 30, 2017, oil and supplies inventories were $4.5 million and $2.5 million, respectively (December 31, 2016 - $6.0 million and $1.8 million, respectively). At September 30, 2017, the Company had 168 Mbbl of oil inventory (December 31, 2016 - 208 Mbbl). In each of the three and nine months ended September 30, 2017, the Company recorded oil inventory impairment of $nil (three and nine months ended September 30, 2016 - $nil and $0.7 million, respectively) related to lower oil prices.

5. Debt and Interest Expense

At September 30, 2017, the Company had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million. 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, the committed borrowing base was increased from $250 million to $300 million effective June 1, 2017. The next re-determination of the borrowing base is due to occur no later than November 2017. On September 18, 2017, the Company entered into the Eighth Amendment to the credit agreement with the other parties thereto, which, among other things, extended the maturity date of the borrowings under the revolving credit facility from September 18, 2018, to October 1, 2018.

The Company's debt at September 30, 2017, and December 31, 2016, was as follows:

(Thousands of U.S. Dollars)	As at September 30, 2017	As at December 31, 2016
Convertible senior notes	**$ 115,000**	$ 115,000
Revolving credit facility	**120,000**	90,000
Unamortized debt issuance costs	**(5,785)**	(7,917)
Long-term debt	**$ 229,215**	$ 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 September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Contractual interest and other financing expenses	**$ 3,346**	$ 2,938	**$ 8,547**	$ 5,029
Amortization of debt issuance costs	**643**	2,184	**1,868**	2,813
	$ 3,989	$ 5,122	**$ 10,415**	$ 7,842

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
Shares repurchased and canceled	(4,235,890)	—	—
Exchange of exchangeable shares	301,230	(142,500)	(158,730)
Shares canceled	(4)	—	—
Balance, September 30, 2017	386,872,530	4,670,092	3,228,572

On February 6, 2017, the Company announced that it had implemented a new share repurchase program (the "2017 Program") through the facilities of the Toronto Stock Exchange ("TSX"), the NYSE American and eligible alternative trading platforms in Canada and the United States. Under the 2017 Program, the Company is able to purchase at prevailing market prices up to 19,540,359 shares of Common Stock, representing 5.0% of the issued and outstanding shares of Common Stock as of January 27, 2017. Shares purchased pursuant to the 2017 Program will be canceled. The 2017 Program will expire on February 7, 2018, or earlier if the 5.0% share maximum is reached.

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 nine months ended September 30, 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	3,229,620	171,388	—	1,964,156	2.54
Exercised	—	—	(211,022)	—	—
Forfeited	(641,159)	—	(9,402)	(903,910)	(4.81)
Expired	—	—	—	(1,396,667)	(4.65)
Balance, September 30, 2017	5,951,178	380,086	138,721	8,903,057	3.66

Stock-based compensation expense for the three and nine months ended September 30, 2017, was $1.8 million and $4.9 million, respectively, and was primarily recorded in general and administrative ("G&A") expenses (three and nine months ended September 30, 2016 - $0.9 million and $4.4 million, respectively).

At September 30, 2017, there was $11.5 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 1.7 years.

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.

Weighted Average Shares Outstanding

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	**2016**	**2017**	**2016**
Weighted average number of common and exchangeable shares outstanding	**394,771,194**	321,725,379	**397,439,007**	304,098,944
Shares issuable pursuant to stock options	**61,325**	—	**187,150**	—
Shares assumed to be purchased from proceeds of stock options	**(57,566)**	—	**(175,520)**	—
Weighted average number of diluted common and exchangeable shares outstanding	**394,774,953**	321,725,379	**397,450,637**	304,098,944

For the three months ended September 30, 2017, 9,259,811 options, on a weighted average basis, (three months ended September 30, 2016 - 9,084,162 options) were excluded from the diluted income (loss) per share calculation as the options were anti-dilutive. For the nine months ended September 30, 2017, 9,744,747 options, on a weighted average basis, (nine months ended September 30, 2016 - 11,155,962 options) were excluded from the diluted income (loss) per share calculation as the options were anti-dilutive. Shares issuable upon conversion of the 5.00% Convertible Senior Notes due 2021 ("Notes") were anti-dilutive and excluded from the diluted income (loss) per share calculation.

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)	**Nine Months Ended September 30, 2017**	**Year Ended December 31, 2016**
Balance, beginning of period	**$ 43,357**	$ 33,224
Liability incurred	**2,942**	2,606
Liabilities assumed in acquisition	**3,513**	15,723
Accretion	**3,101**	2,789
Settlements	**(1,039)**	(872)
Liabilities associated with assets sold	**(2,200)**	(3,257)
Revisions in estimated liability	**(5,670)**	(6,856)
Balance, end of period	**$ 44,004**	$ 43,357
Asset retirement obligation - current	**$ 355**	$ 5,215
Asset retirement obligation - long-term	**43,649**	38,142
	$ 44,004	$ 43,357

For the nine months ended September 30, 2017, settlements included $0.5 million cash payments with the balance in accounts payable and accrued liabilities at September 30, 2017. Revisions in estimated liabilities relate primarily to changes in estimates of asset 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 September 30, 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 85% in the nine months ended September 30, 2017, compared with 31% in the corresponding period in 2016. The Company's effective tax rate differed from the U.S. statutory rate of 35% primarily due to impact of foreign taxes, valuation allowance, non-deductible third-party royalty in Colombia, stock-based compensation and other local taxes. These items were partially offset by foreign currency translation adjustments.

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 $49.8 million as at September 30, 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, the Company has a number of other lawsuits and claims pending. Although the outcome of these other lawsuits and disputes cannot be predicted with certainty, the Company 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 associated with these lawsuits and claims as they are incurred or become probable and determinable.

Letters of credit and other credit support

At September 30, 2017, the Company had provided letters of credit and other credit support totaling $74.5 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 September 30, 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, PSU and DSU liabilities at September 30, 2017, and December 31, 2016, were as follows:

(Thousands of U.S. Dollars)	As at September 30, 2017	As at December 31, 2016
Foreign currency derivative asset	**$ 512**	$ 578
Commodity price derivative liability	**$ 65**	$ 3,824
RSU, PSU and DSU liability	**6,851**	3,907
	$ 6,916	$ 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 September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	2017	2016	2017	2016
Commodity price derivative loss (gain)	**$ 2,489**	$ 2,190	**$ (3,759)**	$ 856
Foreign currency derivatives gain	**(814)**	(840)	**(1,452)**	(1,958)
Trading securities loss	**—**	701	**—**	2,926
Financial instruments loss (gain)	**$ 1,675**	$ 2,051	**$ (5,211)**	$ 1,824

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

Financial instruments not recorded at fair value include the Notes. At September 30, 2017, the carrying amount of the Notes was $110.7 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was $121.9 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 September 30, 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 above regarding the fair value of the Company's revolving credit facility was determined using an income approach using Level 3 inputs. The disclosure 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 September 30, 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: 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

Subsequent to September 30, 2017, the Company entered into the following commodity price contracts:

Period and type of instrument	Volume, bopd	Reference	Purchased Swap ($/bbl)	Purchased Call ($/bbl)
Swap: January 1, to December 31, 2018	2,500	ICE Brent	$ 55.75	
Swap: January 1, to December 31, 2018	2,500	ICE Brent	$ 56.05	
Participating Swap: January 1, to December 31, 2018	2,500	ICE Brent	$ 50.00	$ 54.10

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 expenses. At September 30, 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: October 1, 2017 to October 31, 2017	23,000	7,832	COP	3,000	3,117
Collar: November 1, 2017 to November 30, 2017	25,000	8,513	COP	3,000	3,139
Collar: December 1, 2017 to December 28, 2017	25,000	8,513	COP	3,000	3,142
	73,000	24,858			

[1] At September 30, 2017 foreign exchange rate.

Subsequent to September 30, 2017, the Company entered into the following foreign currency contracts:

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: January 1, 2018 to December 31, 2018	132,000	44,949	COP	3,000	3,112

[1] At September 30, 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 September 30,		As at December 31,	
	2017	2016	2016	2015
Cash and cash equivalents	**$ 15,125**	$ 48,073	$ 25,175	$ 145,342
Restricted cash and cash equivalents - current	**3,920**	13,198	8,322	92
Restricted cash and cash equivalents - long-term	**10,332**	9,993	9,770	3,317
	$ 29,377	$ 71,264	$ 43,267	$ 148,751

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

(Thousands of U.S. Dollars)	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Accounts receivable and other long-term assets	**$ 8,356**	$ 15,233
Derivatives	**—**	(4,563)
Inventory	**(28)**	3,630
Prepaids	**3,080**	1,864
Accounts payable and accrued and other long-term liabilities	**5,951**	(11,297)
Taxes receivable and payable	**(45,464)**	13,230
Net changes in assets and liabilities from operating activities	**$ (28,105)**	$ 18,097

The following table provides additional supplemental cash flow disclosures:

(Thousands of U.S. Dollars)	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	**$ 68,018**	$ 27,520

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

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. Please see the cautionary language at the beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well as Part I, Item 1A "Risk Factors" in our 2016 Annual Report on Form 10-K.

Financial and Operational Highlights

(Thousands of U.S. Dollars, unless otherwise indicated)	Three Months Ended June 30,	Three Months Ended September 30,			Nine Months Ended September 30,		
	2017	2017	2016	% Change	2017	2016	% Change
Average Daily Volumes (BOEPD)							
Consolidated							
Working Interest Production Before Royalties	31,437	**32,570**	25,835	26	**31,305**	25,730	22
Royalties	(5,014)	**(5,055)**	(3,855)	31	**(5,052)**	(3,576)	41
Production NAR	26,423	**27,515**	21,980	25	**26,253**	22,154	19
(Increase) Decrease in Inventory	(140)	**(68)**	(495)	(86)	**(64)**	951	(107)
Sales[1]	26,283	**27,447**	21,485	28	**26,189**	23,105	13
Colombia							
Working Interest Production Before Royalties	30,098	**32,570**	24,874	31	**30,398**	24,859	22
Royalties	(4,819)	**(5,055)**	(3,717)	36	**(4,914)**	(3,439)	43
Production NAR	25,279	**27,515**	21,157	30	**25,484**	21,420	19
(Increase) Decrease in Inventory	(147)	**(68)**	(497)	(86)	**(70)**	949	(107)
Sales[1]	25,132	**27,447**	20,660	33	**25,414**	22,369	14
Net Income (Loss)	$ (6,807)	**$ 3,130**	$(229,619)	101	**$ 9,094**	$(338,210)	103
Operating Netback							
Oil and Natural Gas Sales	$ 96,128	**$ 103,768**	$ 68,539	51	**$ 294,555**	$ 197,655	49
Operating Expenses	(27,208)	**(27,321)**	(25,638)	7	**(78,466)**	(62,453)	26
Transportation Expenses	(6,492)	**(6,038)**	(5,773)	5	**(19,472)**	(24,318)	(20)
Operating Netback[2]	$ 62,428	**$ 70,409**	$ 37,128	90	**$ 196,617**	$ 110,884	77
General and Administrative ("G&A") Expenses, Including Stock-Based Compensation	$ 9,513	**$ 8,651**	$ 5,592	55	**$ 26,876**	$ 20,614	30
Adjusted EBITDA[2]	$ 41,634	**$ 60,491**	$ 24,634	146	**$ 163,663**	$ 89,350	83
Funds Flow From Operations[2]	$ 50,920	**$ 55,128**	$ 23,527	134	**$ 151,074**	$ 68,798	120
Capital Expenditures	$ 57,865	**$ 71,694**	$ 25,080	186	**$ 175,719**	$ 69,667	152

(Thousands of U.S. Dollars)	As at September 30, 2017	December 31, 2016	% Change
Cash, Cash Equivalents and Current Restricted Cash and Cash Equivalents	**$ 19,045**	$ 33,497	(43)
Revolving Credit Facility	**$ 120,000**	$ 90,000	33
Convertible Senior Notes	**$ 115,000**	$ 115,000	—

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

(2) **Non-GAAP measures**

Operating netback, adjusted EBITDA, and funds flow from operations are non-GAAP measures which do not have any standardized meaning prescribed under GAAP. Management views these measures as financial performance measures. Investors are cautioned that these measures should not be construed as alternatives to net income or loss or other measures of financial performance 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.

Operating netback, as presented, is defined as oil and natural 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. A reconciliation from oil and natural gas sales to operating netback is provided in the table above.

Adjusted EBITDA, as presented, is defined as 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 adjusted EBITDA is as follows:

	Three Months Ended June 30,	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	**2017**	**2017**	**2016**	**2017**	**2016**
Net income (loss)	$ (6,807)	**$ 3,130**	$ (229,619)	**$ 9,094**	$ (338,210)
Adjustments to reconcile net income (loss) to adjusted EBITDA					
DD&A expenses	31,644	**34,492**	35,729	**92,729**	104,525
Asset impairment	169	**787**	319,974	**1,239**	469,715
Interest expense	3,331	**3,989**	5,122	**10,415**	7,842
Income tax expense (recovery)	13,297	**18,093**	(106,572)	**50,186**	(154,522)
Adjusted EBITDA (non-GAAP)	$ 41,634	**$ 60,491**	$ 24,634	**$ 163,663**	$ 89,350

Funds flow from operations, as presented, is defined as net income or loss adjusted for DD&A expenses, asset impairment, deferred tax expense or recovery, stock-based compensation, amortization of debt issuance costs, cash settlement of RSUs, unrealized foreign exchange gains and losses, financial instruments gains or losses, cash settlement of financial instruments, loss on sale of Brazil business unit and gain on acquisition. Management uses this financial measure 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 this financial measure is also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income or loss to funds flow from operations is as follows:

	Three Months Ended June 30,	Three Months Ended September 30,		Nine Months Ended September 30,	
(Thousands of U.S. Dollars)	**2017**	**2017**	**2016**	**2017**	**2016**
Net income (loss)	$ (6,807)	**$ 3,130**	$ (229,619)	**9,094**	$ (338,210)
Adjustments to reconcile net income (loss) to funds flow from operations					
DD&A expenses	31,644	**34,492**	35,729	**92,729**	104,525
Asset impairment	169	**787**	319,974	**1,239**	469,715
Deferred tax expense (recovery)	11,525	**13,760**	(110,451)	**36,664**	(166,202)
Stock-based compensation expense	1,980	**1,752**	858	**4,935**	4,380
Amortization of debt issuance costs	620	**643**	2,184	**1,868**	2,813
Cash settlement of RSUs	(183)	**(33)**	(24)	**(534)**	(1,210)
Unrealized foreign exchange loss (gain)	3,895	**(1,380)**	2,387	**(304)**	2,437
Financial instruments (gain) loss	(1,447)	**1,675**	2,051	**(5,211)**	1,824
Cash settlement of financial instruments	448	**302**	438	**1,518**	438
Loss on sale of Brazil business unit	9,076	**—**	—	**9,076**	—
Gain on acquisition	—	**—**	—	**—**	(11,712)
Funds flow from operations (non-GAAP)	$ 50,920	**$ 55,128**	$ 23,527	**$ 151,074**	$ 68,798

Additional Operational Results

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2017	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	% Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	% Change
Oil and natural gas sales	$ 96,128	**$ 103,768**	$ 68,539	51	**$ 294,555**	$ 197,655	49
Operating expenses	27,208	**27,321**	25,638	7	**78,466**	62,453	26
Transportation expenses	6,492	**6,038**	5,773	5	**19,472**	24,318	(20)
Operating netback[(1)]	62,428	**70,409**	37,128	90	**196,617**	110,884	77
DD&A expenses	31,644	**34,492**	35,729	(3)	**92,729**	104,525	(11)
Asset impairment	169	**787**	319,974	(100)	**1,239**	469,715	(100)
G&A expenses before stock-based compensation	7,610	**6,965**	4,778	46	**22,138**	16,414	35
G&A stock-based compensation expense	1,903	**1,686**	814	107	**4,738**	4,200	13
Severance expenses	—	**1,164**	—	—	**1,164**	1,299	(10)
Transaction expenses	—	**—**	6,088	(100)	**—**	7,325	(100)
Equity tax	—	**—**	—	—	**1,224**	3,053	(60)
Foreign exchange loss (gain)	3,897	**(1,271)**	(507)	(151)	**779**	1,059	(26)
Financial instruments (gain) loss	(1,447)	**1,675**	2,051	(18)	**(5,211)**	1,824	(386)
Interest expense	3,331	**3,989**	5,122	(22)	**10,415**	7,842	33
	47,107	**49,487**	374,049	(87)	**129,215**	617,256	(79)
Loss on sale of Brazil business unit	(9,076)	**—**	—	—	**(9,076)**	—	—
Gain on acquisition	—	**—**	—	—	**—**	11,712	(100)
Interest income	245	**301**	730	(59)	**954**	1,928	(51)
Income (loss) before income taxes	6,490	**21,223**	(336,191)	106	**59,280**	(492,732)	112
Current income tax expense	1,772	**4,333**	3,879	12	**13,522**	11,680	16
Deferred income tax expense (recovery)	11,525	**13,760**	(110,451)	112	**36,664**	(166,202)	122
	13,297	**18,093**	(106,572)	117	**50,186**	(154,522)	132
Net income (loss)	$ (6,807)	**$ 3,130**	$ (229,619)	101	**$ 9,094**	$ (338,210)	103
Sales Volumes (NAR)							
Total sales volumes, BOEPD	26,283	**27,447**	21,485	28	**26,189**	23,105	13
Average Prices							
Oil and NGL's per bbl	$ 40.44	**$ 41.44**	$ 34.79	19	**$ 41.58**	$ 31.34	33
Natural gas per Mcf	$ 2.52	**$ 1.89**	$ 3.40	(44)	**$ 1.90**	$ 3.07	(38)
Brent Price per bbl	$ 50.92	**$ 52.18**	$ 46.98	11	**$ 52.59**	$ 42.07	25

Consolidated Results of Operations per BOE Sales Volumes NAR							
Oil and natural gas sales	$ 40.19	**$ 41.09**	$ 34.68	18	**$ 41.20**	$ 31.22	32
Operating expenses	11.38	**10.82**	12.97	(17)	**10.97**	9.86	11
Transportation expenses	2.71	**2.39**	2.92	(18)	**2.72**	3.84	(29)
Operating netback[1]	26.10	**27.88**	18.79	48	**27.51**	17.52	57
DD&A expenses	13.23	**13.66**	18.08	(24)	**12.97**	16.51	(21)
Asset impairment	0.07	**0.31**	161.88	(100)	**0.17**	74.20	(100)
G&A expenses before stock-based compensation	3.18	**2.76**	2.42	14	**3.10**	2.60	19
G&A stock-based compensation expense	0.80	**0.67**	0.41	63	**0.66**	0.66	—
Severance expenses	—	**0.46**	—	—	**0.16**	0.21	(24)
Transaction expenses	—	**—**	3.08	(100)	**—**	1.16	(100)
Equity tax	—	**—**	—	—	**0.17**	0.48	(65)
Foreign exchange loss (gain)	1.63	**(0.50)**	(0.26)	(92)	**0.11**	0.17	(35)
Financial instruments (gain) loss	(0.60)	**0.66**	1.04	(37)	**(0.73)**	0.29	(352)
Interest expense	1.39	**1.58**	2.59	(39)	**1.46**	1.24	18
	19.70	**19.60**	189.24	(90)	**18.07**	97.52	(81)
Loss on sale of Brazil business unit	(3.79)	**—**	—	—	**(1.27)**	—	—
Gain on acquisition	—	**—**	—	—	**—**	1.85	(100)
Interest income	0.10	**0.12**	0.37	(68)	**0.13**	0.30	(57)
Income (loss) before income taxes	2.71	**8.40**	(170.08)	105	**8.30**	(77.85)	111
Current income tax expense	0.74	**1.72**	1.96	(12)	**1.89**	1.84	3
Deferred income tax expense (recovery)	4.82	**5.45**	(55.88)	110	**5.13**	(26.25)	120
	5.56	**7.17**	(53.92)	113	**7.02**	(24.41)	129
Net income (loss)	$ (2.85)	**$ 1.23**	$ (116.16)	101	**$ 1.28**	$ (53.44)	102

[1] Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to "Financial and Operating Highlights—non-GAAP measures" for a definition and reconciliation of this measure.

As previously announced, we continue to evaluate strategic disposition alternatives for our assets in Peru, which may not be core to our ongoing plans. Any such disposition may involve a contribution of such assets to a separate entity in which we would retain a non-controlling equity interest. The new company may engage in external capital raising activities to fund the ongoing development of the Peruvian assets. We have not entered into any definitive agreement and cannot provide assurances that any disposition will be completed.

Oil and Gas Production and Sales Volumes, BOEPD

Average Daily Volumes (BOEPD)	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
	Colombia	Brazil	Total	Colombia	Brazil	Total
Working Interest Production Before Royalties	**32,570**	**—**	**32,570**	24,874	961	25,835
Royalties	**(5,055)**	**—**	**(5,055)**	(3,717)	(138)	(3,855)
Production NAR	**27,515**	**—**	**27,515**	21,157	823	21,980
(Increase) Decrease in Inventory	**(68)**	**—**	**(68)**	(497)	2	(495)
Sales	**27,447**	**—**	**27,447**	20,660	825	21,485
Royalties, % of Working Interest Production Before Royalties	**16%**	**—%**	**16%**	15 %	14 %	15 %

Average Daily Volumes (BOEPD)	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
	Colombia	Brazil	Total	Colombia	Brazil	Total
Working Interest Production Before Royalties	**30,398**	**907**	**31,305**	24,859	871	25,730
Royalties	**(4,914)**	**(138)**	**(5,052)**	(3,439)	(137)	(3,576)
Production NAR	**25,484**	**769**	**26,253**	21,420	734	22,154
(Increase) Decrease in Inventory	**(70)**	**6**	**(64)**	949	2	951
Sales	**25,414**	**775**	**26,189**	22,369	736	23,105
Royalties, % of Working Interest Production Before Royalties	**16%**	**15%**	**16%**	14 %	16 %	14 %

Oil and gas production NAR for the three and nine months ended September 30, 2017, increased by 25% to 27,515 BOEPD and 19% to 26,253 BOEPD, respectively, compared with 21,980 BOEPD and 22,154 BOEPD respectively, in the comparable periods in 2016. We increased oil and gas production NAR despite the sale of our Brazil business unit on June 30, 2017. In the three and nine months ended September 30, 2017, production increased primarily due to the PetroLatina acquisition and a successful drilling campaign in the Acordionero Field in Colombia. The acquisition of PetroLatina Energy Limited closed on August 23, 2016, at which time the Acordionero field was producing approximately 4,730 bopd before royalties. After a successful drilling campaign, production from the Acordionero Field averaged 10,743 bopd and 8,451 bopd, respectively, before royalties during the three and nine months ended September 30, 2017

Royalties as a percentage of production for the three and nine months ended September 30, 2017, increased compared with the comparable period in the prior year commensurate with the increase in oil prices.

Despite the sale of our Brazil assets effective June 30, 2017, oil and gas production NAR for the three months ended September 30, 2017, increased 4% compared with the prior quarter as a result of a successful drilling and workover campaign in the Acordionero Field in Colombia, the successful Vonu-1 exploration well and a workover campaign in Cumplidor. Colombian NAR production increased 9% compared with the prior quarter.

Oil and gas sales volumes for the three months ended September 30, 2017, increased by 28% to 27,447 BOEPD compared with 21,485 BOEPD in the corresponding period in 2016. Higher working interest production (6,735 BOEPD) and lower inventory increases (427 BOEPD) more than offset higher royalty volumes (1,200 BOEPD).

For the nine months ended September 30, 2017, oil and gas sales volumes increased by 13% to 26,189 BOEPD compared with 23,105 BOEPD in the corresponding period in 2016. Higher working interest production (5,575 BOEPD) more than offset the combination of higher royalty volumes (1,476 BOEPD) and inventory changes (1,015 BOEPD).

Oil and gas sales volumes for the three months ended September 30, 2017, increased by 4% to 27,447 BOEPD compared with 26,283 BOEPD in the prior quarter. Sales volumes increased due to higher working interest production (1,133 BOEPD) and lower inventory changes (72 BOEPD) more than offset higher royalty volumes (41 BOEPD).

Operating Netbacks

	Three Months Ended September 30, 2017			Three Months Ended September 30, 2016		
(Thousands of U.S. Dollars)	Colombia	Brazil	Total	Colombia	Brazil	Total
Oil and Natural Gas Sales	$ 103,768	$ —	$ 103,768	$ 65,944	$ 2,595	$ 68,539
Transportation Expenses	(6,038)	—	(6,038)	(5,644)	(129)	(5,773)
	97,730	—	97,730	60,300	2,466	62,766
Operating Expenses	(27,321)	—	(27,321)	(24,899)	(739)	(25,638)
Operating Netback(1)	$ 70,409	$ —	$ 70,409	$ 35,401	$ 1,727	$ 37,128
U.S. Dollars Per BOE Sales Volumes NAR						
Brent	$ 52.18	$ —	$ 52.18	$ 46.98	$ 46.98	$ 46.98
Quality and Transportation Discounts	(11.09)	—	(11.09)	(12.29)	(12.77)	(12.30)
Average Realized Price	41.09	—	41.09	34.69	34.21	34.68
Transportation Expenses	(2.39)	—	(2.39)	(2.97)	(1.70)	(2.92)
Average Realized Price Net of Transportation Expenses	38.70	—	38.70	31.72	32.51	31.76
Operating Expenses	(10.82)	—	(10.82)	(13.10)	(9.74)	(12.97)
Operating Netback(1)	$ 27.88	$ —	$ 27.88	$ 18.62	$ 22.77	$ 18.79

	Nine Months Ended September 30, 2017			Nine Months Ended September 30, 2016		
(Thousands of U.S. Dollars)	Colombia	Brazil	Total	Colombia	Brazil	Total
Oil and Natural Gas Sales	$ 286,137	$ 8,418	$ 294,555	$ 191,515	$ 6,140	$ 197,655
Transportation Expenses	(19,122)	(350)	(19,472)	(24,005)	(313)	(24,318)
	267,015	8,068	275,083	167,510	5,827	173,337
Operating Expenses	(76,669)	(1,797)	(78,466)	(61,057)	(1,396)	(62,453)
Operating Netback(1)	$ 190,346	$ 6,271	$ 196,617	$ 106,453	$ 4,431	$ 110,884
U.S. Dollars Per BOE Sales Volumes NAR						
Brent	$ 52.59	$ 52.59	$ 52.59	$ 42.07	$ 42.07	$ 42.07
Quality and Transportation Discounts	(11.35)	(12.83)	(11.39)	(10.82)	(11.61)	(10.85)
Average Realized Price	41.24	39.76	41.20	31.25	30.46	31.22
Transportation Expenses	(2.76)	(1.65)	(2.72)	(3.92)	(1.55)	(3.84)
Average Realized Price Net of Transportation Expenses	38.48	38.11	38.48	27.33	28.91	27.38
Operating Expenses	(11.05)	(8.49)	(10.97)	(9.96)	(6.92)	(9.86)
Operating Netback(1)	$ 27.43	$ 29.62	$ 27.51	$ 17.37	$ 21.99	$ 17.52

(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 and nine months ended September 30, 2017, increased by 51% to $103.8 million and by 49% to $294.6 million, respectively, from $68.5 million and $197.7 million, respectively, in the comparable periods in 2016 due to increased volumes and 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 and nine months ended September 30, 2017:

	Third Quarter 2017 Compared with Second Quarter 2017	Third Quarter 2017 Compared with Third Quarter 2016	Nine Months Ended, September 30, 2017 Compared with Nine Months Ended September 30, 2016
Oil and natural gas sales for the comparative period	$ 96,128	$ 68,539	$ 197,655
Realized sales price increase effect	2,285	16,206	71,333
Sales volume increase effect	5,355	19,023	25,567
Oil and natural gas sales for period ended September 30, 2017	**$ 103,768**	**$ 103,768**	**$ 294,555**

Average realized prices for the three and nine months ended September 30, 2017, increased by 18% and 32%, respectively, commensurate with the increase in benchmark oil prices and lower transportation and quality discounts. Average Brent oil prices for the three and nine months ended September 30, 2017, increased by 11% and 25% respectively.

Oil and gas sales for the three months ended September 30, 2017, increased by 8% to $103.8 million from $96.1 million compared with the prior quarter due to higher sales volumes and increased realized oil prices. Average realized prices increased by 2% to $41.09 per BOE for the three months ended September 30, 2017, compared with $40.19 per BOE in the prior quarter. Average Brent oil prices for the three months ended September 30, 2017, increased by 2% to $52.18 per bbl, compared with $50.92 per bbl in the prior quarter.

We have options to sell our oil though multiple pipelines and trucking routes. 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 and nine months ended September 30, 2017 and 2016 and the prior quarter:

	Three Months Ended June 30,	Three Months Ended September 30,		Nine Months Ended September 30,	
	2017	2017	2016	2017	2016
Volume transported through pipeline	20%	**10%**	36%	**18%**	50%
Volume sold at wellhead, trucking	52%	**57%**	56%	**54%**	40%
Volume sold not at wellhead, trucking	28%	**33%**	8%	**28%**	10%
	100%	**100%**	100%	**100%**	100%

Volumes not sold at the wellhead receive a higher realized price, but incur higher transportation expenses. Volumes sold at the wellhead have the opposite effect of lower realized price, offset by lower transportation expense.

Transportation expenses for the three months ended September 30, 2017, increased by 5% to $6.0 million compared with the corresponding period in 2016. On a per BOE basis, transportation expenses decreased by 18% to $2.39 per BOE from $2.92 per BOE in the corresponding period in 2016. The decrease in transportation expenses per BOE was due to the use of transportation routes which had lower costs per BOE than the routes used in 2016.

Transportation expenses for the nine months ended September 30, 2017, decreased by 20% to $19.5 million compared with the corresponding period in 2016. On a per BOE basis, transportation expenses decreased by 29% to $2.72 per BOE from $3.84 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 transportation routes which had lower costs per BOE than the routes used in 2016.

Transportation expenses for the three months ended September 30, 2017, decreased 7% to $6.0 million compared with $6.5 million in the prior quarter. On a per BOE basis, transportation expenses decreased by 12% to $2.39 from $2.71 in the prior quarter. The decrease was primarily due to the use of transportation routes which had lower costs per BOE.

The following table shows the variance in our ***average realized prices net of transportation expenses*** in Colombia for the three and nine months ended September 30, 2017 compared with the comparative period in 2016 and the prior quarter:

U.S. Dollars Per BOE Sales Volumes NAR	**Third Quarter 2017 Compared with Second Quarter 2017**	**Third Quarter 2017 Compared with Third Quarter 2016**	**Nine Months Ended, September 30, 2017 Compared with Nine Months Ended September 30, 2016**
Average realized price net of transportation expenses for the comparative period	$ 37.42	$ 31.72	$ 27.33
Increase in benchmark prices	1.26	$ 5.20	10.52
(Increase) decrease in quality and transportation discounts	(0.35)	1.20	(0.53)
Lower transportation expenses	0.37	0.58	1.16
Average realized price net of transportation expenses for period ended September 30, 2017	**$ 38.70**	**$ 38.70**	**$ 38.48**

Operating expenses for the three months ended September 30, 2017, increased by 7% to $27.3 million compared with the corresponding period in 2016. The increase was primarily due to higher sales volumes. On a per BOE basis, operating expenses decreased by 17% to $10.82 per BOE from $12.97 per BOE, in the corresponding period in 2016 primarily as a result of decreased workover expenses of $2.97 per BOE. In the comparative period in 2016, we deferred workover activity to the second half of the year due to low commodity prices. Excluding workover expenses, operating costs increased by $0.82 per BOE as discussed below.

In Colombia, operating costs for the three months ended September 30, 2017, decreased by $2.28 per BOE compared with the corresponding period in 2016, primarily as a result of decreased workover expenses of $3.16 per BOE. Excluding workover expenses, operating expenses in Colombia increased by $0.88 per BOE primarily as result of the NaturAmazonas reforestation and conservation program signed on January 30, 2017. After several months of planning and discussion, we signed an agreement with Conservation International to launch NaturAmazonas, a five year reforestation and conservation program to be implemented by Conservation International in the Putumayo Region of Colombia. Conservation International is a non-government organization, well-known for implementing and managing nature conservation projects around the world. During the three and nine months ended September 30, 2017, operating expenses included $0.8 million and $2.5 million, respectively, related to this program.

As previously reported in our Quarterly Report on Form 10-Q filed with the SEC on August 4, 2017, since the Mocoa natural disaster, the electrical system in the Putumayo region has experienced instability, and we have had to utilize gas and diesel generators to maintain production and injection at key wells during brief periods of electrical outage. The instability of electricity not only increases our operating costs it also has a negative impact on our production in the Putumayo Basin and water injection program in both Costayaco and Moqueta. We are currently expanding a gas to electrical power facility in Costayaco which will enable consistent power generation. We expect the expanded facility to be in place by the end of 2017.

Operating expenses for the nine months ended September 30, 2017, increased by 26% to $78.5 million, compared with the corresponding period in 2016. The increase was due to higher sales volumes and increased operating costs per BOE. On a per BOE basis, operating expenses increased by 11% to $10.97 per BOE from $9.86 per BOE, in the corresponding period in 2016. Workover expenses decreased by $0.21 per BOE compared with the corresponding period in the prior year. Excluding workover expenses, operating costs increased by $1.32 per BOE primarily as a result of the NaturAmazonas reforestation and conservation program discussed above.

Colombian operating expenses for the nine months ended September 30, 2017, increased by $1.09 per BOE compared with the corresponding period in 2016. Workover expenses decreased by $0.23 per BOE. Excluding workover expenses, operating expenses in Colombia increased by $1.32 per BOE primarily as a result of increased costs and production disruptions in 2017, as described above.

Operating expenses were comparable to the prior quarter at $27.3 million in the three months ended September 30, 2017. On a per BOE basis, operating expenses decreased by $0.56 to $10.82 per BOE for the three months ended September 30, 2017, from $11.38 per BOE in the prior quarter primarily as a result of decreased workover expenses of $0.90 per BOE.

DD&A Expenses

	Three Months Ended September 30, 2017		Three Months Ended September 30, 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	$ 33,388	$ 13.22	$ 34,156	$ 17.97
Brazil	—	—	1,022	13.47
Peru	881	—	206	—
Corporate	223	—	345	—
	$ 34,492	$ 13.66	$ 35,729	$ 18.08

	Nine Months Ended September 30, 2017		Nine Months Ended September 30, 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	$ 88,453	$ 12.75	$ 100,350	$ 16.37
Brazil	2,263	10.69	2,764	13.71
Peru	1,350	—	418	—
Corporate	663	—	993	—
	$ 92,729	$ 12.97	$ 104,525	$ 16.51

DD&A expenses for the three and nine months ended September 30, 2017, decreased to $34.5 million ($13.66 per BOE) and $92.7 million ($12.97 per BOE) from $35.7 million ($18.08 per BOE) and $104.5 million ($16.51 per BOE) in the comparable periods in 2016. On a per BOE basis, the decrease was due to lower costs in the depletable base and increased proved reserves.

On a per BOE basis, DD&A expenses increased by 3% to $13.66 per BOE for the three months ended September 30, 2017, from $13.23 per BOE in the prior quarter due to higher costs in the depletable base from capital expenditures during the quarter ended September 30, 2017.

Asset Impairment

(Thousands of U.S. Dollars)	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Impairment of oil and gas properties				
Colombia	**$ —**	$ 298,370	**$ —**	$ 431,146
Brazil	**—**	21,604	**—**	37,006
Peru	**176**	—	**628**	899
Mexico	**611**	—	**611**	—
	787	319,974	**1,239**	469,051
Impairment of inventory	**—**	—	**—**	664
	$ 787	$ 319,974	**$ 1,239**	$ 469,715

Impairment losses in the comparative periods in 2016 in our Colombia and Brazil cost centers and inventory impairment were primarily due to lower oil prices. In accordance with GAAP, we used an average Brent price of $52.70 per bbl for the purposes of the September 30, 2017, ceiling test calculations (June 30, 2017 - $51.35, March 31, 2017 - $49.33; December 31, 2016 - $42.92; September 30, 2016 - $42.23; June 30, 2016 - $44.48, March 31, 2016 - $48.79; December 31, 2015 - $54.08).

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.

G&A Expenses

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2017	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	% Change	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016	% Change
G&A Expenses Before Stock-Based Compensation	$ 7,610	**$ 6,965**	$ 4,778	46	**$ 22,138**	$ 16,414	35
G&A Stock-Based Compensation	1,903	**1,686**	814	107	**4,738**	4,200	13
G&A Expenses, Including Stock-Based Compensation	$ 9,513	**$ 8,651**	$ 5,592	55	**$ 26,876**	$ 20,614	30
U.S. Dollars Per BOE Sales Volumes NAR							
G&A Expenses Before Stock-Based Compensation	$ 3.18	**$ 2.76**	$ 2.42	14	**$ 3.10**	$ 2.60	19
G&A Stock-Based Compensation	0.80	**0.67**	0.41	63	**0.66**	0.66	—
G&A Expenses, Including Stock-Based Compensation	$ 3.98	**$ 3.43**	$ 2.83	21	**$ 3.76**	$ 3.26	15

G&A expenses before stock based compensation decreased by 8% compared with the prior quarter. For the three and nine months ended September 30, 2017, G&A expenses increased by 46% and 35%, respectively, from the corresponding periods in 2016. The increase was commensurate with our growth. Since June 30, 2016, we have completed two acquisitions, drilled 25 wells, and grown production NAR 25% from 21,980 BOEPD in the third quarter of 2016 to 27,515 BOEPD in 2017.

After stock-based compensation, G&A expenses for the three and nine months ended September 30, 2017, increased by 55% to $8.7 million ($3.43 per BOE) and by 30% to $26.9 million ($3.76 per BOE), respectively, from $5.6 million ($2.83 per BOE) and $20.6 million ($3.26 per BOE), respectively, in the corresponding periods in 2016. The increase was mainly due to the increased head count.

G&A expenses for the three months ended September 30, 2017, decreased by 9% to $8.7 million ($3.43 per BOE) compared with $9.5 million ($3.98 per BOE) in the prior quarter.

Equity Tax Expense

For the nine months ended September 30, 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 and nine months ended September 30, 2017, we had foreign exchange gains of $1.3 million and losses of $0.8 million, respectively, compared with foreign exchange gains of $0.5 million and losses of $1.1 million, respectively, in the corresponding periods 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 and nine months ended September 30, 2017, and 2016:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2017	**2016**	**2017**	**2016**
Change in the U.S. dollar against the Colombian peso	**weakened by 3%**	weakened by 1%	**weakened by 2%**	weakened by 9%

Financial Instrument Gains and Losses

The following table presents the nature of our financial instruments gains and losses for the three and nine months ended September 30, 2017, and 2016:

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(Thousands of U.S. Dollars)	**2017**	**2016**	**2017**	**2016**
Commodity price derivative loss (gain)	**$ 2,489**	$ 2,190	**$ (3,759)**	$ 856
Foreign currency derivatives gain	**(814)**	(840)	**(1,452)**	(1,958)
Trading securities loss	**—**	701	**—**	2,926
	$ 1,675	$ 2,051	**$ (5,211)**	$ 1,824

Income Tax Expense and Recovery

(Thousands of U.S. Dollars)	Three Months Ended September 30, 2017	Three Months Ended September 30, 2016	Nine Months Ended September 30, 2017	Nine Months Ended September 30, 2016
Income (loss) before income tax	**$ 21,223**	$ (336,191)	**$ 59,280**	$ (492,732)
Current income tax expense	**$ 4,333**	$ 3,879	**$ 13,522**	$ 11,680
Deferred income tax expense (recovery)	**13,760**	(110,451)	**36,664**	(166,202)
Total income tax expense (recovery)	**$ 18,093**	$ (106,572)	**$ 50,186**	$ (154,522)
Effective tax rate			**85%**	31%
Deferred income tax recovery related to Colombia ceiling test impairment	**$ —**	$ 119,348	**$ —**	$ 172,458

Current income tax expense was higher in the three months ended September 30, 2017, compared with the corresponding period in 2016 primarily as a result of higher taxable income in Colombia. The deferred income tax expense of $13.8 million for the three months ended September 30, 2017, was primarily due to excess tax depreciation compared with accounting depreciation in Colombia. The deferred income tax recovery in the corresponding period in 2016 of $110.5 million included $119.3 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.

Current income tax expense was higher in the nine months ended September 30, 2017, compared with the corresponding period in 2016 as a result of higher taxable income in Colombia. The deferred income tax expense of $36.7 million for the nine months ended September 30, 2017, was primarily due to excess tax depreciation compared with accounting depreciation in Colombia. The deferred income tax recovery in the corresponding period in 2016 of $166.2 million included $172.5 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 85% in the nine months ended September 30, 2017, compared with 31% in the corresponding period in 2016. The increase in the effective tax rate for the nine months ended September 30, 2017, was primarily due to the impact of foreign taxes, foreign currency translation adjustments, non-deductible third-party royalty in Colombia and stock based compensation, which were partially offset by decreases in the valuation allowance, other permanent differences and other local taxes.

For the nine months ended September 30, 2017, the difference between the effective tax rate of 85% and the 35% U.S. statutory rate was primarily due to the effect of foreign taxes, valuation allowances, non-deductible third party royalty in Colombia, stock-based compensation and other local taxes. These items were partially offset by foreign currency translation adjustments and other permanent differences.

For the nine months ended September 30, 2016, the difference between the effective tax rate of 31% and the 35% U.S. statutory rate was primarily due to an increase to the valuation allowance, which was largely attributable to impairment losses in Brazil and Colombia, as well as non-deductible local taxes, stock based compensation and the non-deductible third-party royalty in Colombia. These items were partially offset by the impact of foreign taxes, foreign currency translation adjustments and other permanent differences. Other permanent differences mainly related to a non-taxable gain arising on the acquisition of Petroamerica, partially offset by prior periods' true-up adjustments, uncertain tax position adjustments and other expenses deductible for tax.

Net Income and Funds Flow from Operations (a Non-GAAP Measure)

(Thousands of U.S. Dollars)	Third Quarter 2017 Compared with Second Quarter 2017	% change	Third Quarter 2017 Compared with Third Quarter 2016	% change	Nine Months Ended, September 30, 2017 Compared with Nine Months Ended September 30, 2016	% change
Net loss for the comparative period	$ (6,807)		$ (229,619)		$ (338,210)	
Increase (decrease) due to:						
Prices	2,285		16,206		71,333	
Sales volumes	5,355		19,023		25,567	
Expenses:						
Operating	(113)		(1,683)		(16,013)	
Transportation	454		(265)		4,846	
Cash G&A and RSU settlements, excluding stock-based compensation expense	784		(2,174)		(5,031)	
Transaction	—		6,088		7,325	
Severance	(1,164)		(1,164)		135	
Interest, net of amortization of debt issuance costs	(635)		(408)		(3,518)	
Realized foreign exchange	(107)		(3,004)		(2,461)	
Settlement of financial instruments	(146)		(136)		1,080	
Current taxes	(2,561)		(454)		(1,842)	
Equity tax	—		—		1,829	
Other	56		(428)		(974)	
Net change in funds flow from operations[1] from comparative period	4,208		31,601		82,276	
Expenses:						
Depletion, depreciation and accretion	(2,848)		1,237		11,796	
Asset impairment	(618)		319,187		468,476	
Deferred tax	(2,235)		(124,211)		(202,866)	
Amortization of debt issuance costs	(23)		1,541		945	
Stock-based compensation, net of RSU settlement	78		(885)		(1,231)	
Financial instruments gain or loss, net of financial instruments settlements	(2,976)		512		5,955	
Unrealized foreign exchange	5,275		3,767		2,741	
Loss on sale of Brazil business unit	9,076		—		(9,076)	
Gain on acquisition	—		—		(11,712)	
Net change in net income or loss	9,937		232,749		347,304	
Net income for the current period	**$ 3,130**	**146%**	**$ 3,130**	**101%**	**$ 9,094**	**103%**

[1]Funds flow from operations 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.

2017 Capital Program

We expect the range of our projected 2017 capital program to be $225 million to $250 million. 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 September 30, 2017, were $71.7 million:

(Thousands of U.S. Dollars)		
Colombia	$	70,606
Peru		998
Corporate		90
	$	71,694

During the nine months ended September 30, 2017, we drilled the following wells in Colombia:

	Number of wells (Gross)	Number of wells (Net)
Development	15	11.6
Exploration	4	2.6
Total Colombia	19	14.2

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

- On the Chaza Block (100% working interest ("WI"), operated), we successfully drilled Costayaco-30, a directional well targeting the Caballos formation, the U-Sand and A-Limestone in the northern portion of Costayaco field. Costayaco-30 completion work is underway.

- On the Putumayo-7 Block (100% WI, operated), we completed the Cumplidor and Northwest 3-D seismic programs targeting the A-Limestone.

- On the Midas Block (100% WI, operated), we drilled, completed and brought on production as oil producers five development wells: Acordionero-12, Acordionero-13, Acordionero-15, Acordionero-17 and Mochuelo-1ST. We successfully completed a workover on the Mochuelo well targeting oil in the Lisama formation and source water for use in Acordionero waterflood. We also commenced drilling the Acordionero-18 and Acordionero-14i wells and completed water injection tests on Acordionero-8i.

- On the Putumayo-1 Block (55% WI, operated), we completed a production test at the Vonu-1 exploration well with successful production results.

- On the Putumayo-4 Block (100% WI, operated), we started drilling the Siriri-1 exploration well.

- On the Suroriente Block (15.8% WI, non-operated), we completed drilling the Cohembi-21 development well and commenced drilling the Cohembi-22 development well.

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

Liquidity and Capital Resources

(Thousands of U.S. Dollars)	As at September 30, 2017		% Change	December 31, 2016	
Cash and Cash Equivalents	**$**	**15,125**	(40)	$	25,175
Current Restricted Cash and Cash Equivalents	**$**	**3,920**	(53)	$	8,322
Revolving Credit Facility	**$**	**120,000**	33	$	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 banks 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 September 30, 2017, we had a revolving credit facility with a syndicate of lenders with a borrowing base of $300 million. 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, the committed borrowing base was increased from $250 million to $300 million effective June 1, 2017. The next re-determination of the borrowing base is due to occur no later than November 2017. On September 18, 2017, we entered into the Eighth Amendment to our credit agreement with the other parties thereto, which, among other things, extended the maturity date of the borrowings under the revolving credit facility from September 18, 2018 to October 1, 2018. Subject to documentation, the maturity date of the borrowings under the revolving credit facility is expected to be further extended to November 2020 and the borrowing base is expected to be confirmed at $300 million until May 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 (as defined in our credit agreement, "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 September 30, 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 5.00% Convertible Senior Notes due 2021 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 September 30, 2017, 97% 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 other than to pay head office charges, 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.

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 September 30, 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: 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

Subsequent to September 30, 2017, we entered into the following commodity price contracts:

Period and type of instrument	Volume, bopd	Reference	Purchased Swap ($/bbl)	Purchased Call ($/bbl)
Swap: January 1, to December 31, 2018	2,500	ICE Brent	$ 55.75	
Swap: January 1, to December 31, 2018	2,500	ICE Brent	$ 56.05	
Participating Swap: January 1, to December 31, 2018	2,500	ICE Brent	$ 50.00	$ 54.10

At September 30, 2017, we had the following outstanding foreign currency derivative positions:

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: October 1, 2017 to October 31, 2017	23,000	7,832	COP	3,000	3,117
Collar: November 1, 2017 to November 30, 2017	25,000	8,513	COP	3,000	3,139
Collar: December 1, 2017 to December 28, 2017	25,000	8,513	COP	3,000	3,142
	73,000	24,858			

[1] At September 30, 2017 foreign exchange rate.

Subsequent to September 30, 2017, the we entered into the following foreign currency contracts:

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: January 1, 2018 to December 31, 2018	132,000	44,949	COP	3,000	3,112

Cash Flows

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

	Nine Months Ended September 30, 2017	2016
Sources of cash and cash equivalents:		
Net income (loss)	**$ 9,094**	$ (338,210)
Adjustments to reconcile net income (loss) to funds flow from operations		
DD&A expenses	**92,729**	104,525
Asset impairment	**1,239**	469,715
Deferred tax expense (recovery)	**36,664**	(166,202)
Stock-based compensation expense	**4,935**	4,380
Amortization of debt issuance costs	**1,868**	2,813
Cash settlement of RSUs	**(534)**	(1,210)
Unrealized foreign exchange (gain) loss	**(304)**	2,437
Financial instruments (gain) loss	**(5,211)**	1,824
Cash settlement of financial instruments	**1,518**	438
Loss on sale of Brazil business unit	**9,076**	—
Gain on acquisition	**—**	(11,712)
Funds flow from operations	**151,074**	68,798
Proceeds from bank debt, net of issuance costs	**115,264**	220,169
Proceeds from sale of Brazil business unit, net of cash sold	**34,481**	—
Cash deposit received for letter of credit arrangements upon sale of Brazil business unit	**4,700**	—
Changes in non-cash investing working capital	**11,347**	—
Net changes in assets and liabilities from operating activities	**—**	18,097
Proceeds from sale of marketable securities	**—**	788
Proceeds from issuance of subscription receipts, net of issuance costs	**—**	165,805
Proceeds from issuance of Notes, net of issuance costs	**—**	109,090
Proceeds from issuance of shares	**—**	5,169
	316,866	587,916
Uses of cash and cash equivalents:		
Additions to property, plant and equipment	**(175,719)**	(69,667)
Additions to property, plant and equipment - property acquisitions	**(30,410)**	(19,388)
Repayment of bank debt	**(85,000)**	(110,181)
Repurchase of shares of Common Stock	**(10,000)**	—
Net changes in assets and liabilities from operating activities	**(28,105)**	—
Changes in non-cash investing working capital	**—**	(8,036)
Settlement of asset retirement obligations	**(462)**	(496)
Foreign exchange loss on cash, cash equivalents and restricted cash and cash equivalents	**(1,060)**	(452)
Acquisition of Petroamerica, net of cash acquired	**—**	(457,183)
	(330,756)	(665,403)
Net decrease in cash and cash equivalents and restricted cash and cash equivalents	**$ (13,890)**	$ (77,487)

Cash provided by operating activities in the nine months ended September 30, 2017, was primarily affected by higher funds flow from operations (see reconciliation of net income (loss) to funds flow from operations under the heading 'Financial and Operational Highlights' above) and a $28.1 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 September 30, 2017, we had no off-balance sheet arrangements.

Contractual Obligations

During the nine months ended September 30, 2017, we borrowed a net amount of $30.3 million on our revolving credit facility. Additionally, at June 30, 2017, we sold our Brazil business unit and its related obligations. Except as noted above, as at September 30, 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 nine months ended September 30, 2017, we had no ceiling test impairment losses in our Colombia and Brazil cost centers. We used an average Brent price of $52.70 per bbl for the purposes of the September 30, 2017 ceiling test calculations (June 30, 2017 - $51.35, March 31, 2017 - $49.33; December 31, 2016 - $42.92; September 30, 2016 - $42.23; June 30, 2016 - $44.48, 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 Colombia cost center in the fourth 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 fourth 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 a pro forma Brent oil price of $54.16 per bbl for the year ended December 31, 2017. This pro forma oil price was 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 October 31, 2017, and, for the two months ended December 31, 2017, estimated oil prices for the fourth quarter of 2017 using the forward price curve forecast from Bloomberg dated September 30, 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.

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 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 Colombia and Peru are in local currency. Certain G&A expenses incurred at our head office in Canada are denominated in Canadian dollars. 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 September 30, 2017, our outstanding revolving credit facility was $120.0 million (December 31, 2016 - $90.0 million), which had a weighted-average interest rate of approximately 3.5%. A 10% change in LIBOR would not materially impact our interest expense on debt outstanding at September 30, 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(b) 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 of September 30, 2017.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 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 2016 Annual Report on Form 10-K. The risks facing our company have not changed materially from those set forth in Part I, Item 1A Risk Factors of our 2016 Annual Report on Form 10-K.

Item 6. *Exhibits*

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 Exhibit 3.1 to Exhibit 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	Eighth Amendment to Credit Agreement, dated as of September 18, 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 September 21, 2017 (SEC File No. 001-34018).
10.2	Amendment #4, dated August 31, 2017, to the Share and Loan Purchase Agreement dated February 5, 2017 between Gran Tierra Energy International Holdings Ltd., Gran Tierra Luxembourg Holdings S.A.R.L. and Maha Energy AB.	Filed herewith.
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.

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: November 2, 2017	/s/ Gary S. Guidry
	By: Gary S. Guidry President and Chief Executive Officer (Principal Executive Officer)
Date: November 2, 2017	/s/ Ryan Ellson
	By: Ryan Ellson Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT 10.2

August 31, 2017

Gran Tierra Energy International Holdings Ltd.
and Gran Tierra Luxembourg Holdings S.á.r.l.
c/o Gran Tierra Energy Inc.
900, 520 – 3rd Avenue S.W.
Calgary, Alberta
T2P 0R3

Attention: General Counsel

Amendment to the Share and Loan Purchase Agreement dated February 5, 2017, as amended on May 30, 2017, June 22, 2017 and June 26, 2017 (the "Share and Loan Purchase Agreement") between Gran Tierra Energy International Holdings Ltd., Gran Tierra Luxembourg Holdings S.Á.R.L. and Maha Energy AB.

Capitalized terms used herein and not otherwise defined shall have the meaning ascribed thereto in the Share and Loan Purchase Agreement.

Whereas:

1. Purchaser has delivered the Final Closing Statement to Vendor on August 28, 2017 (the "**Delivery Date**"); and

2. the Parties wish to extend the time for the Vendors to review the Final Closing Statement, and to provide a mechanism during this time for the Vendor to obtain clarifying information from the Purchaser and for the Parties to engage in discussions to attempt to resolve outstanding matters in connection with the Final Closing Statement, without triggering the dispute mechanism provisions of subsection 2.9(b) of the Share and Loan Purchase Agreement;

Now therefore, the Parties agree, pursuant to Section 14.10 of the Share and Loan Purchase Agreement, to amend the Share and Loan Purchase Agreement by entering into this letter agreement (the "**Fourth Amending Agreement**") to delete subsection 2.9(b) of the Share and Loan Purchase Agreement in its entirety and replace it with the following:

> *The Vendor will have a period of sixty (60) days from the date of delivery of the Final Closing Statement to review and agree or dispute the Final Closing Statement. If the Vendor disputes the Final Closing Statement it must notify the Purchaser in writing within the sixty (60) day period referred to above, giving full details of each of the matters in dispute. During the sixty (60) day period referred to above, the Vendors and Purchaser shall, prior to the Vendors serving any written notice of*

their disagreement, use good faith efforts to engage in without prejudice discussions regarding any potential disagreement over the Final Closing Statement and Purchaser shall assist the Vendors in verifying the amounts set forth in such Final Closing Statement as part of these without prejudice discussions. The Final Closing Statement, or if applicable such revised Final Closing Statement as agreed to in writing by the Vendors and the Purchaser at the conclusion of such good faith efforts, shall constitute the final and binding Final Closing Statement with respect to the Vendors unless the Vendors have served written notice of their disagreement, including full details of such disagreement, to the Purchaser within the sixty (60) day period referred to above. The Parties may extend the above sixty (60) day period by mutual agreement in writing. If the Final Closing Statement is disputed by the Vendors, the Purchaser and the Vendors shall have a period of ten (10) Business Days from the service of the notice of the Vendor's disagreement in which to resolve the matters in dispute. During this period the Vendors and the Purchaser may, by notice in writing, propose further adjustments and notify the other of additional matters in dispute, but only where such additional adjustments or matters arise out of any disagreement notified by the Vendor in the original notice of dispute. At the end of such period, the Final Closing Statement shall be revised to reflect any agreed adjustments. Payment of any agreed adjustments, plus interest thereon at the Interest Rate from the Closing Date to the payment date, shall be made within ten (10) Business Days following agreement of the disputing Parties. If any matter remains in dispute at the end of the ten (10) Business Day period referred to above (the "Disputed Amounts") then, at the written request of either the Vendors or the Purchaser, an Independent Auditor shall be promptly engaged to resolve such dispute and the Independent Auditor shall be requested to render its decision without qualifications, other than the usual qualifications relating to engagements of this nature, within thirty (30) Business Days after the dispute is referred to it. The decision of the Independent Auditor will be final and binding. The fees and expenses of the Independent Auditor shall be for the sole account of the Vendors, unless the Independent Auditor's decision is to the benefit of the Vendors by at least $250,000.00, in which circumstance the fees and expenses of the Independent Auditor shall be borne in their entirety by the Purchaser.

The Parties agree that the foregoing amendments are effective as of the date first above written.

Except as modified by this Fourth Amending Agreement, the terms of the Share and Loan Purchase Agreement are hereby ratified and confirmed and any reference to the Share and Loan Purchase Agreement shall be deemed to be the Share and Loan Purchase Agreement as amended by this Fourth Amending Agreement.

This Fourth Amending Agreement shall be governed by, construed and enforced in accordance with the laws in effect in the Province of Alberta and the federal laws of Canada applicable therein.

This Fourth Amending Agreement may be executed in any number of counterparts with the same effect as if all signatories to the counterparts had signed one document. All counterparts shall together constitute and be construed as one instrument. For avoidance of doubt, a signed counterpart provided by way of facsimile transmission or other electronic means shall be as binding upon the Parties as an originally signed counterpart.

This Fourth Amending Agreement has been duly executed by the Parties as of the date first above written.

GRAN TIERRA ENERGY INTERNATIONAL HOLDINGS LTD.

Per: /s/ Adrian Santiago Coral Pantoja
Name: Adrian Santiago Coral Pantoja
Title: Director

MAHA ENERGY AB

Per: /s/ Jonas Lindvall
Name: Jonas Lindvall
Title: Chief Executive Officer

GRAN TIERRA LUXEMBOURG HOLDINGS S.Á.R.L.

Per: /s/ Adrian Santiago Coral Pantoja
Name: Adrian Santiago Coral Pantoja
Title: Authorized Manager A

Signature page to the Fourth Amending Agreement

Exhibit 12.1

STATEMENT RE: COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
(in thousands)

Our earnings were insufficient to cover fixed charges for the years ended December 31, 2016, 2015 and 2014. The following table sets forth our ratio of earnings to fixed charges for the nine months ended September 30, 2017, and the years ended December 31, 2013 and 2012, and our deficiency of earnings available to cover fixed charges for the years ended December 31, 2016, 2015 and 2014.

	Nine Months Ended September 30,	Year Ended December 31,				
	2017	**2016**	**2015**	**2014**	**2013**	**2012**
Fixed charges						
Contractual interest and other financing expenses	**$ 8,547**	$ 8,454	$ —	$ —	$ —	$ —
Amortization of debt issuance costs	**1,868**	5,691	—	—	—	—
Interest portion of rental expense	**42**	44	31	18	21	27
Total fixed charges	**$ 10,457**	$ 14,189	$ 31	$ 18	$ 21	$ 27
Earnings						
Income (loss) income from continuing operations before tax	**$ 59,280**	$ (650,234)	$ (368,088)	$ (17,134)	$ 309,284	$ 196,349
Fixed charges per above	**10,457**	14,189	31	18	21	27
	$ 69,737	$ (636,045)	$ (368,057)	$ (17,116)	$ 309,305	$ 196,376
Ratio of earnings to fixed charges	**7**				14,729	7,273
Deficiency of earnings available to cover fixed charges		$ (636,045)	$ (368,057)	$ (17,116)		

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Gary S. Guidry, certify that:

1. I have reviewed this Form 10-Q of Gran Tierra Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2017	/s/ Gary S. Guidry
	By: Gary S. Guidry
	President and Chief Executive Officer
	(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER
PURSUANT TO RULE 13A-14(A) AND RULE 15D-14(A)
OF THE SECURITIES EXCHANGE ACT OF 1934, AS AMENDED

I, Ryan Ellson, certify that:

1. I have reviewed this Form 10-Q of Gran Tierra Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 2, 2017	/s/ Ryan Ellson
	By: Ryan Ellson
	Chief Financial Officer
	(Principal Financial and Accounting Officer)

EXHIBIT 32.1

CERTIFICATIONS PURSUANT TO

18 U.S.C. §1350,

AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report on Form 10-Q of Gran Tierra Energy Inc. (the “Company”) for the quarter ended September 30, 2017, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), Gary S. Guidry, President and Chief Executive Officer of the Company, and Ryan Ellson, Chief Financial Officer of the Company, each hereby certifies, to the best of his knowledge, pursuant to 18 U.S.C. §1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report, to which this Certification is attached as Exhibit 32.1, fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Dated: November 2, 2017

/s/ Gary S. Guidry	/s/ Ryan Ellson
By: Gary S. Guidry	By: Ryan Ellson
President and Chief Executive Officer	Chief Financial Officer

This certification accompanies the Form 10-Q to which it relates, is not deemed filed with the SEC and is not to be incorporated by reference into any filing of the Company under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended (whether made before or after the date of the Form 10-Q), irrespective of any general incorporation language contained in such filing.