

GRAN TIERRA ENERGY INC.
Form 10-Q
August 08, 2016

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 June 30, 2016

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)

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

200, 150 13 Avenue S.W.
Calgary, Alberta, Canada T2R 0V2
(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 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting 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

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

On August 2, 2016, the following number of shares of the registrant's capital stock were outstanding: 289,322,888 shares of the registrant's Common Stock, \$0.001 par value; one share of Special A Voting Stock, \$0.001 par value, representing 3,638,889 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 4,875,177 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 June 30, 2016

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words "believe", "expect", "anticipate", "intend", "estimate", "project", "target", "goal", "plan", "objective", "should", or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part II, Item 1A "Risk Factors" in this Quarterly Report on Form 10-Q and in Part I, Item 1A "Risk Factors" in our 2015 Annual Report on Form 10-K. The information included herein is given as of the filing date of this Quarterly Report on Form 10-Q with the Securities and Exchange Commission ("SEC") and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

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

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

Sales volumes represent production NAR adjusted for inventory changes and losses. 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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
OIL AND NATURAL GAS SALES (NOTE 4)	\$71,713	\$ 69,350	\$ 129,116	\$ 145,581
EXPENSES				
Operating	17,748	17,758	36,815	40,419
Transportation	6,217	6,375	18,545	15,148
Depletion, depreciation and accretion (Note 4)	31,884	39,188	68,796	88,328
Asset impairment (Notes 4 and 5)	92,843	30,285	149,741	67,299
General and administrative (Note 4)	7,975	10,298	16,261	17,592
Severance	281	1,988	1,299	6,366
Equity tax (Note 9)	—	—	3,051	3,769
Foreign exchange loss (gain)	781	2,969	1,566	(8,569)
Financial instruments gain (Note 12)	(1,072)	(1,366)	(227)	(1,408)
	156,657	107,495	295,847	228,944
GAIN ON ACQUISITION (NOTE 3)	—	—	11,712	—
INTEREST EXPENSE (NOTE 6)	(2,201)	—	(2,720)	—
INTEREST INCOME	749	382	1,198	803
LOSS BEFORE INCOME TAXES (NOTE 4)	(86,396)	(37,763)	(156,541)	(82,560)
INCOME TAX (EXPENSE) RECOVERY				
Current	(5,778)	(5,684)	(7,801)	(8,109)
Deferred	28,615	4,883	55,751	7,239
	22,837	(801)	47,950	(870)
NET LOSS AND COMPREHENSIVE LOSS	\$(63,559)	\$ (38,564)	\$(108,591)	\$(83,430)
NET LOSS PER SHARE - BASIC AND DILUTED	\$(0.21)	\$(0.13)	\$(0.37)	\$(0.29)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC AND DILUTED (Note 7)	296,565,530	286,393,772	295,188,878	286,294,595

(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)

	June 30, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 171,470	\$ 145,342
Restricted cash (Notes 3 and 5)	9,716	92
Accounts receivable	43,733	29,217
Marketable securities (Note 12)	3,979	6,250
Derivatives (Note 12)	7,014	—
Inventory (Note 5)	9,339	19,056
Taxes receivable	30,387	28,635
Other current assets	5,112	5,848
Total Current Assets	280,750	234,440
Oil and Gas Properties		
Proved	372,752	469,589
Unproved	366,079	310,771
Total Oil and Gas Properties	738,831	780,360
Other capital assets	8,432	8,633
Total Property, Plant and Equipment (Notes 4 and 5)	747,263	788,993
Other Long-Term Assets		
Restricted cash	6,750	3,317
Taxes receivable	9,497	8,276
Other long-term assets	15,578	8,511
Goodwill (Note 4)	102,581	102,581
Total Other Long-Term Assets	134,406	122,685
Total Assets (Note 4)	\$ 1,162,419	\$ 1,146,118
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	\$ 65,850	\$ 70,778
Taxes payable	1,115	1,067
Asset retirement obligation (Note 8)	2,970	2,146
Total Current Liabilities	69,935	73,991
Long-Term Liabilities		
Convertible senior notes (Notes 6 and 12)	109,145	—
Deferred tax liabilities	5,552	34,592
Asset retirement obligation (Note 8)	40,870	31,078
Other long-term liabilities	10,921	4,815
Total Long-Term Liabilities	166,488	70,485
Contingencies (Note 11)		
Subsequent Events (Note 14)		
Shareholders' Equity		

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Common Stock (Note 7) (289,322,888 and 273,442,799 shares of Common Stock and 8,514,066 and 8,572,066 exchangeable shares, par value \$0.001 per share, issued and outstanding as at June 30, 2016, and December 31, 2015, respectively)	10,202	10,186
Additional paid in capital	1,052,792	1,019,863
Deficit	(136,998)	(28,407)
Total Shareholders' Equity	925,996	1,001,642
Total Liabilities and Shareholders' Equity	\$1,162,419	\$1,146,118

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30,	
	2016	2015
Operating Activities		
Net loss	\$(108,591)	\$(83,430)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation and accretion (Note 4)	68,796	88,328
Asset impairment (Notes 4 and 5)	149,741	67,299
Deferred tax recovery	(55,751)	(7,239)
Stock-based compensation expense (Note 7)	3,522	1,113
Amortization of debt issuance costs (Note 6)	629	—
Cash settlement of restricted share units	(1,186)	(1,314)
Unrealized foreign exchange loss (gain)	50	(5,564)
Financial instruments gain (Note 12)	(227)	(1,408)
Cash settlement of financial instruments	47	(3,749)
Cash settlement of asset retirement obligation (Note 8)	(464)	(1,964)
Gain on acquisition (Note 3)	(11,712)	—
Net change in assets and liabilities from operating activities (Note 13)	(6,630)	(46,504)
Net cash provided by operating activities	38,224	5,568
Investing Activities		
Increase in restricted cash	(2,349)	(320)
Additions to property, plant and equipment, excluding Corporate acquisition (Note 4)	(44,587)	(91,318)
Additions to property, plant and equipment - acquisition of PetroGranada Colombia Limited (Note 5)	(19,388)	—
Changes in non-cash investing working capital	(11,059)	(77,109)
Cash paid for business combination, net of cash acquired (Note 3)	(50,909)	—
Net cash used in investing activities	(128,292)	(168,747)
Financing Activities		
Proceeds from issuance of the Notes, net of issuance costs (Note 6)	108,900	—
Proceeds from issuance of shares of Common Stock (Note 7)	5,350	602
Net cash provided by financing activities	114,250	602
Foreign exchange gain (loss) on cash and cash equivalents	1,946	(2,872)
Net increase (decrease) in cash and cash equivalents	26,128	(165,449)
Cash and cash equivalents, beginning of period	145,342	331,848
Cash and cash equivalents, end of period	\$ 171,470	\$ 166,399

Supplemental cash flow disclosures (Note 13)

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30, 2016	Year Ended December 31, 2015
Share Capital		
Balance, beginning of period	\$10,186	\$10,190
Issuance of Common Stock (Note 7)	16	—
Repurchase of Common Stock	—	(4)
Balance, end of period	10,202	10,186
Additional Paid in Capital		
Balance, beginning of period	1,019,863	1,026,873
Issuance of Common Stock (Note 7)	25,798	—
Exercise of stock options (Note 7)	5,347	722
Stock-based compensation (Note 7)	1,784	2,263
Repurchase of Common Stock	—	(9,995)
Balance, end of period	1,052,792	1,019,863
Retained Earnings (Deficit)		
Balance, beginning of period	(28,407)	239,622
Net loss	(108,591)	(268,029)
Balance, end of period	(136,998)	(28,407)
Total Shareholders' Equity	\$925,996	\$1,001,642

(See notes to the condensed consolidated financial statements)

Gran Tierra Energy Inc.

Notes to the Condensed Consolidated Financial Statements (Unaudited)

(Expressed in U.S. Dollars, unless otherwise indicated)

1. Description of Business

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

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, 2015, included in the Company’s 2015 Annual Report on Form 10-K, filed with the SEC on February 29, 2016.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2015 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.

Convertible Senior Notes

The Company accounts for its 5.00% Convertible Senior Notes due 2021 (the “Notes”) as a liability in their entirety. The embedded features of the Notes were assessed for bifurcation from the Notes under the applicable provisions, including the basic conversion feature, the fundamental change make-whole provision and the put and call options. Based on an assessment, the Company concluded that these embedded features did not meet the criteria to be accounted for separately.

The Company incurred debt issuance costs in connection with the issuance of the Notes which have been presented as a direct deduction against the carrying amount of the Notes and are being amortized to interest expense using the effective interest method over the contractual term of the Notes.

Derivatives

The Company's commodity price and foreign currency derivatives are recorded on its interim unaudited condensed consolidated balance sheet at fair value as either an asset or a liability with changes in fair value recognized in the interim unaudited condensed consolidated statements of operations. While the Company utilizes derivative instruments to manage the price risk attributable to its expected oil production and foreign exchange risk, it has elected not to designate its derivative instruments as accounting hedges under the accounting guidance.

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the Financial Accounting Standards Board (the "FASB") issued guidance regarding the accounting for revenue from contracts with customers. In August 2015, the FASB issued Accounting Standards Update ("ASU") 2015-14, "Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU defers 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 2016, the FASB issued ASU 2016-10, "Identifying Performance Obligations and Licensing" which clarifies implementation guidance. In May 2016, the FASB issued ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients" which reduces the potential for diversity in practice at initial application and the cost and complexity of applying

Topic 606 both at transition and on an ongoing basis. The Company is currently assessing the impact the new revenue recognition model will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Simplifying the Accounting for Measurement - Period Adjustments

In September 2015, the FASB issued ASU 2015-16, "Simplifying the Accounting for Measurement - Period Adjustments". The amendments require that an acquirer recognize adjustments to provisional amounts identified during the measurement period in the reporting period in which the adjustments are determined and eliminates the requirement to retrospectively revise prior periods. Additionally, an acquirer should record in the same period the effects on earnings of any changes in the provisional accounts, calculated as if the accounting had been completed at the acquisition date. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The implementation of this update is not expected to materially impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases". This ASU will require most lease assets and lease liabilities to be recognized on the balance sheet and the disclosure of key information about lease arrangements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2018. The Company is currently assessing the impact the new lease standard will have on its consolidated financial position, results of operations, cash flows, and 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 will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

3. Business Combination

On January 13, 2016 (the "Petroamerica Acquisition Date"), the Company acquired all of the issued and outstanding common shares of Petroamerica Oil Corp. ("Petroamerica"), a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated November 12, 2015 (the "Arrangement"). The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petroamerica shareholders and by the Court of Queen's Bench of Alberta on January 11, 2016. Under the Arrangement, each Petroamerica shareholder was entitled to receive, for each Petroamerica share held, either 0.40 of a Gran Tierra common share or \$1.33 Canadian dollars in cash, or a combination of shares and cash, subject to a maximum of 70% of the consideration payable in cash.

As consideration for the acquisition of all the issued and outstanding Petroamerica shares, the Company issued approximately 13.7 million shares of Gran Tierra Common Stock, par value \$0.001, and paid cash consideration of approximately \$70.6 million. The fair value of Gran Tierra's Common Stock issued was determined to be \$25.8 million based on the closing price of shares of Common Stock of Gran Tierra as at the Petroamerica Acquisition Date. Total net purchase price of Petroamerica was \$72.2 million, after giving consideration to net working capital of \$24.2 million. Upon completion of the transaction on the Petroamerica Acquisition Date, Petroamerica became an indirect wholly-owned subsidiary of Gran Tierra.

The acquisition was accounted for as a business combination using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recognized at their fair values as at the Petroamerica Acquisition Date, and the results of Petroamerica were included with those of Gran Tierra from that date. Fair value estimates were made based on significant unobservable (Level 3) inputs and based on the best information available at the time.

The following table shows the allocation of the consideration transferred based on the fair values of the assets and liabilities acquired:

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(Thousands of U.S. Dollars)

Consideration Transferred:

Cash	\$70,625
Shares of Common Stock issued net of share issue costs	25,811
	\$96,436

Allocation of Consideration Transferred⁽¹⁾:

Oil and gas properties	
Proved	\$48,595
Unproved	50,054
Net working capital (including cash acquired of \$19.7 million, restricted cash of \$2.5 million and accounts receivable of \$5.0 million)	24,202
Long-term restricted cash	8,167
Other long-term assets	1,570
Long-term deferred tax liability	(10,105)
Long-term portion of asset retirement obligation	(11,556)
Other long-term liabilities	(2,779)
Gain on acquisition	(11,712)
	\$96,436

⁽¹⁾ The allocation of the consideration transferred is incomplete and is subject to change. Management is continuing to review and assess information to accurately determine the acquisition date fair value of the assets and liabilities acquired. During the measurement period, Gran Tierra will continue to obtain information to assist in finalizing the fair value of net assets acquired, which may differ materially from the above preliminary estimates.

As indicated in the allocation of the consideration transferred, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized a "Gain on acquisition" of \$11.7 million in the interim unaudited condensed consolidated statement of operations for the six months ended June 30, 2016. The gain reflects the impact on Petroamerica's pre-acquisition market value resulting from the company's lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

Pro Forma Results (unaudited)

Pro forma results for the six months ended June 30, 2016 and 2015, are shown below, as if the acquisition had occurred on January 1, 2015. Pro forma results are not indicative of actual results or future performance.

(Unaudited, thousands of U.S. Dollars, except per share amounts)	Six Months Ended	
	2016	2015
Oil and gas sales	\$129,587	\$178,509
Net loss	\$(120,317)	\$(138,535)
Net loss per share - basic and diluted	\$(0.41)	\$(0.48)

The supplemental pro forma net loss of Gran Tierra for the six months ended June 30, 2016, was adjusted to exclude the \$11.7 million gain on acquisition and \$1.3 million of acquisition costs recorded in general and administrative ("G&A") expenses because they were not expected to have a continuing impact on Gran Tierra's results of operations.

The Company's consolidated statement of operations for the six months ended June 30, 2016, included oil and gas sales of \$8.9 million and a loss after tax of \$18.2 million from Petroamerica for the period subsequent to the Petroamerica Acquisition Date.

4. Segment and Geographic Reporting

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The Company is primarily engaged in the exploration and production of oil and natural gas. The Company's reportable segments are Colombia, Peru and Brazil based on geographic organization. The All Other category represents the Company's corporate activities. The Company evaluates reportable segment performance based on income or loss before income taxes.

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

Three Months Ended June 30, 2016					
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$69,271	\$ —	\$2,442	\$ —	\$71,713
Depletion, depreciation and accretion	30,458	71	1,024	331	31,884
Asset impairment	78,208	483	14,152	—	92,843
General and administrative expenses	4,430	387	241	2,917	7,975
Loss before income taxes	(64,836)	(744)	(14,037)	(6,779)	(86,396)
Segment capital expenditures	14,535	1,102	2,160	610	18,407
Three Months Ended June 30, 2015					
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$67,627	\$ —	\$1,723	\$ —	\$69,350
Depletion, depreciation and accretion	37,061	147	1,575	405	39,188
Asset impairment	—	5,285	25,000	—	30,285
General and administrative expenses	3,035	1,273	965	5,025	10,298
Income (loss) before income taxes	3,197	(8,261)	(28,211)	(4,488)	(37,763)
Segment capital expenditures	8,173	6,878	2,505	316	17,872
Six Months Ended June 30, 2016					
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$125,571	\$ —	\$3,545	\$ —	\$129,116
Depletion, depreciation and accretion	66,194	212	1,742	648	68,796
Asset impairment	133,440	899	15,402	—	149,741
General and administrative expenses	7,695	796	533	7,237	16,261
Loss before income taxes	(137,557)	(1,456)	(15,546)	(1,982)	(156,541)
Segment capital expenditures ⁽¹⁾	36,522	2,369	4,880	816	44,587
Six Months Ended June 30, 2015					
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	\$141,694	\$ —	\$3,887	\$ —	\$145,581
Depletion, depreciation and accretion	83,316	414	3,836	762	88,328
Asset impairment	—	37,966	29,333	—	67,299
General and administrative expenses	5,751	2,313	1,592	7,936	17,592
Income (loss) before income taxes	6,125	(43,703)	(35,092)	(9,890)	(82,560)
Segment capital expenditures	29,295	44,577	16,411	1,035	91,318

⁽¹⁾ On January 13, 2016, the Company acquired all of the issued and outstanding common shares of Petroamerica, which acquisition was accounted for as a business combination (Note 3) and, therefore, property, plant and equipment acquired are not reflected in the table above. Additionally, on January 25, 2016, the Company acquired all of the issued and outstanding common shares of PetroGranada Colombia Limited ("PGC"), which acquisition was accounted for as an asset acquisition (Note 5) and property, plant and equipment acquired in this acquisition are not reflected in

the table above.

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	As at June 30, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	\$543,273	\$96,433	\$103,368	\$4,189	\$747,263
Goodwill	102,581	—	—	—	102,581
All other assets	146,191	16,404	3,211	146,769	312,575
Total Assets	\$792,045	\$112,837	\$106,579	\$150,958	\$1,162,419

	As at December 31, 2015				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	\$574,351	\$95,069	\$115,552	\$4,021	\$788,993
Goodwill	102,581	—	—	—	102,581
All other assets	93,479	21,111	2,236	137,718	254,544
Total Assets	\$770,411	\$116,180	\$117,788	\$141,739	\$1,146,118

5. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at June 30, 2016	As at December 31, 2015
Oil and natural gas properties		
Proved	\$2,111,268	\$1,998,330
Unproved	366,079	310,771
	2,477,347	2,309,101
Other	28,597	28,342
	2,505,944	2,337,443
Accumulated depletion, depreciation and impairment	(1,758,681)	(1,548,450)
	\$747,263	\$788,993

In the three and six months ended June 30, 2016, the Company recorded ceiling test impairment losses in its Colombia cost center of \$78.2 million and \$132.8 million, respectively, and in its Brazil cost center of \$14.2 million and \$15.4 million, respectively, related to lower oil prices. In the three and six months ended June 30, 2015, the Company recorded ceiling test impairment losses in its Brazil cost center of \$25.0 million and \$29.3 million, related to lower oil prices.

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

In the three and six months ended June 30, 2016, and 2015, the Company recorded impairment losses in its Peru cost center of \$0.5 million and \$0.9 million and \$5.3 million and \$38.0 million, respectively, related to costs incurred on Block 95.

Asset impairment for the three and six months ended June 30, 2016, and 2015 was as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2016	2015	2016	2015
Impairment of oil and gas properties	\$92,843	\$30,285	\$149,077	\$67,299
Impairment of inventory	—	—	664	—
	\$92,843	\$30,285	\$149,741	\$67,299

Acquisition of PGC

On January 25, 2016, the Company acquired all of the issued and outstanding common shares of PGC, pursuant to the terms and conditions of an acquisition agreement dated January 14, 2016. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra. The net purchase price of PGC was \$19.4 million, after giving consideration to net working capital of \$18.3 million. The acquisition was accounted for as an asset acquisition with the excess consideration transferred over the fair value of the net assets acquired 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	\$37,727
Allocation of Consideration Transferred:	
Oil and gas properties	
Proved	\$12,228

Unproved	15,563
	27,791
Net working capital (including cash acquired of \$0.2 million and restricted cash of \$18.6 million)	18,339
Long-term deferred tax liability	(8,403)
	\$37,727

Contingent consideration of \$4.0 million will be payable if cumulative production from the Putumayo-7 Block plus gross proved plus probable reserves under the Putumayo Block meet or exceed 8 MMbbl. PGC is an oil and gas exploration,

development and production company active in Colombia. Contingent consideration will be recognized when the contingency is resolved.

Inventory

At June 30, 2016, oil and supplies inventories were \$8.0 million and \$1.3 million, respectively (December 31, 2015 - \$17.8 million and \$1.3 million, respectively). At June 30, 2016, the Company had 244 Mbbbl of oil inventory (December 31, 2015 - 616 Mbbbl) NAR. In the six months ended June 30, 2016, the Company recorded oil inventory impairment of \$0.7 million (six months ended June 30, 2015 - \$nil) related to lower oil prices.

6. Convertible Senior Notes and Debt Issuance Costs

On April 6, 2016, the Company issued \$100 million aggregate principal amount of Notes in a private placement to qualified institutional buyers. On April 22, 2016, the Company issued an additional \$15 million aggregate principal amount of the Notes pursuant to the underwriters' exercise of their option to acquire additional Notes. The Notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October 1, 2016. The Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted.

The Notes are convertible at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. The conversion rate is initially 311.4295 shares of Common Stock per \$1,000 principal amount of Notes (equivalent to an initial conversion price of approximately \$3.21 per share of Common Stock). The conversion rate is subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date, the Company will increase the conversion rate for a holder who elects to convert its Notes in connection with such a corporate event in certain circumstances.

The Company may not redeem the Notes prior to April 5, 2019, except in certain circumstances following a fundamental change (as defined in the indenture governing the Notes). The Company may redeem for cash all or any portion of the Notes, at its option, on or after April 5, 2019, if (terms below are as defined in the indenture governing the Notes):

(i) the last reported sale price of the Company's Common Stock has been at least 150% of the conversion price then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which the Company provides notice of redemption; and

(ii) the Company has filed all reports that it is required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act, as applicable (other than current reports on Form 8-K), during the twelve months preceding the date on which the Company provides such notice.

The redemption price will be equal to 100% of the principal amount of the Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date. No sinking fund is provided for the Notes.

If the Company undergoes a fundamental change, holders may require the Company to repurchase for cash all or any portion of their Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

Net proceeds from the sale of the Notes were \$108.9 million, after deducting the initial purchasers' discount and the offering expenses payable by the Company. The Company intends to use the net proceeds from the sale of Notes for general corporate purposes, which may include acquisitions and/or capital expenditures.

In connection with the issuance of the Notes, the Company incurred \$6.1 million of debt issuance costs, which have been presented as a direct deduction against the carrying amount of the Notes. As of June 30, 2016, the balance of unamortized debt issuance costs was \$5.9 million. The Company also incurred debt issuance costs in connection with its credit facility which have been presented as other long-term assets and are being amortized to interest expense using the effective interest method over the term of the credit facility.

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 June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Contractual interest and other financing expenses	\$1,712	\$ —	-\$2,091	\$ —
Amortization of debt issuance costs	489	—	629	—
	\$2,201	\$ —	-\$2,720	\$ —

7. 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, 2015	273,442,799	4,933,177	3,638,889
Shares issued for acquisition (Note 3)	13,656,719	—	—
Options exercised	2,165,370	—	—
Exchange of exchangeable shares	58,000	(58,000)) —
Balance, June 30, 2016	289,322,888	4,875,177	3,638,889

Loss per Share

Basic loss per share is calculated by dividing 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 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Weighted average number of common and exchangeable shares outstanding	296,565,530	286,393,772	295,188,878	286,294,595
Weighted average shares issuable pursuant to stock options	—	—	—	—
Weighted average shares assumed to be purchased from proceeds of stock options	—	—	—	—
Weighted average number of diluted common and exchangeable shares outstanding	296,565,530	286,393,772	295,188,878	286,294,595

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

Equity Compensation Awards

In December 2015, the Company's Board of Directors approved a new equity compensation program for 2016 to realign the Company's compensation programs with its renewed short and long-term strategy. The 2016 equity compensation program reflects the Company's emphasis on pay-for-performance.

In prior years, all equity awards were subject to vesting conditions based solely on the recipient's continued employment over a specified period of time. In contrast, 80% of the equity awards granted in early 2016 consisted of Performance Stock Units ("PSUs") and 20% consisted of stock options. Gran Tierra's Compensation Committee and Board of Directors believed it was important to revise the Company's long-term incentive program to incorporate a new form of equity award that vests based on the achievement of certain key measures of performance. The purpose of this change was to align the Company's executives and employees to achieve the operational goals established by the Board of Directors, total shareholder return and increase the net asset value per share for stockholders. The Company's equity compensation awards outstanding as of June 30, 2016, include PSUs, deferred share units ("DSUs"), restricted stock units ("RSUs") and stock options.

The Company records stock-based compensation expense, measured at the fair value of the awards that are ultimately expected to vest, in the consolidated financial statements. Fair values are determined using pricing models such as the Black-Scholes-Merton or Monte Carlo simulation stock option-pricing models and/or observable share prices. For equity-settled stock-based compensation awards, fair values are determined at the grant date and are recognized over the requisite service period. For cash-settled stock-based compensation awards, fair values are determined at each reporting date and periodic changes are recognized as compensation costs, with a corresponding change to liabilities. Stock-based compensation expense is capitalized as part of oil and natural gas properties or expensed as part of operating expenses or G&A expenses, as appropriate.

The following table provides information about PSU, DSU, RSU and stock option activity for the six months ended June 30, 2016:

	PSUs	DSUs	RSUs	Stock Options	Weighted Average Exercise Price/Stock Option (\$)
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Stock Options	
Balance, December 31, 2015	—	—	1,015,457	12,851,557	4.60
Granted	2,297,700	117,621	—	1,302,350	2.65
Exercised	—	—	(460,614)	(2,165,370)	2.47
Forfeited	—	—	(173,830)	(1,563,903)	(6.07)
Expired	—	—	—	(1,517,500)	(6.41)
Balance, June 30, 2016	2,297,700	117,621	381,013	8,907,134	4.27

The amounts recognized for stock-based compensation were as follows:

(Thousands of U.S. Dollars)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Compensation costs for PSUs	\$707	\$—	\$871	\$—
Compensation costs for stock options	813	1,109	1,784	687
Compensation costs for DSUs	404	—	550	—
Compensation costs for RSUs	341	597	705	537
	2,265	1,706	3,910	1,224
Less: Stock-based compensation costs capitalized	(203)	(80)	(388)	(111)
Stock-based compensation expense	\$2,062	\$1,626	\$3,522	\$1,113

Stock-based compensation expense for the three and six months ended June 30, 2016 and 2015, was primarily recorded in G&A expenses.

At June 30, 2016, there was \$9.9 million (December 31, 2015 - \$3.9 million) of unrecognized compensation cost related to unvested PSUs, stock options, DSUs and RSUs which is expected to be recognized over a weighted average period of 2.2 years.

PSUs

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PSUs entitle the holder to receive, at the option of the Company, either the underlying number of shares of the Company's Common Stock upon vesting of such units or a cash payment equal to the value of the underlying shares. PSUs will cliff vest after three years, subject to the continued employment of the grantee. The number of PSUs that vest may range from zero to 200% of the target number granted based on the Company's performance with respect to the applicable performance targets. The performance targets for the PSUs outstanding as of June 30, 2016, are as follows:

- (i) 50% of the award is subject to targets relating to the total shareholder return ("TSR") of the Company against a group of peer companies;
- (ii) 25% of the award is subject to targets relating to net asset value ("NAV") of the Company per share and NAV is based on before tax net present value discounted at 10% of proved plus probable reserves; and
- (iii) 25% of the award is subject to targets relating to the execution of corporate strategy.

The compensation cost of PSUs is subject to adjustment based upon the attainability of these performance targets. No settlement will occur with respect to the portion of the PSU award subject to each performance target for results below the applicable minimum threshold for that target. PSUs in excess of the target number granted will vest and be settled if performance exceeds the targeted performance goals. The Company currently intends to settle PSUs in cash.

DSUs and RSUs

DSUs and RSUs entitle the holder to receive, either the underlying number of shares of the Company's Common Stock upon vesting of such units or, at the option of the Company, a cash payment equal to the value of the underlying shares. The Company's historic practice has been to settle RSUs in cash and the Company currently intends to settle the RSUs and DSUs outstanding as of June 30, 2016 in cash. Once a DSU or RSU is vested, it is immediately settled. During the six months ended June 30, 2016, DSUs were granted to directors and will vest 100% at such time the grantee ceases to be a member of the Board of Directors.

Stock Options

Each stock option permits the holder to purchase one share of Common Stock at the stated exercise price. The exercise price equals the market price of a share of Common Stock at the time of grant. Stock options generally vest over three years. The term of stock options granted starting in May of 2013 is five years or three months after the grantee's end of service to the Company, whichever occurs first. Stock options granted prior to May of 2013 continue to have a term of ten years or three months after the end of the grantee's service to the Company, whichever occurs first.

For the six months ended June 30, 2016, 2,165,370 shares of Common Stock were issued for cash proceeds of \$5.4 million (six months ended June 30, 2015 - \$0.6 million) upon the exercise of stock options.

The weighted average grant date fair value for stock options granted in three months ended June 30, 2016, was \$1.06 (three months ended June 30, 2015 - \$1.43) and for the six months ended June 30, 2016, was \$1.12 (six months ended June 30, 2015 - \$1.28).

8. 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)	Six	
	Months Ended June 30, 2016	Year Ended December 31, 2015
Balance, beginning of period	\$33,224	\$ 35,812
Settlements	(681)	(6,317)
Liability incurred	1,208	1,556
Liabilities assumed in acquisition (Note 3)	11,852	—
Accretion	1,273	1,313
Revisions in estimated liability	(3,036)	860
Balance, end of period	\$43,840	\$ 33,224
Asset retirement obligation - current	\$2,970	\$ 2,146
Asset retirement obligation - long-term	40,870	31,078
	\$43,840	\$ 33,224

For the six months ended June 30, 2016, settlements included cash payments of \$0.5 million with the balance in accounts payable and accrued liabilities at June 30, 2016. Revisions to 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 the asset retirement obligation. At June 30, 2016, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was \$8.9 million (December 31, 2015 - \$2.9 million). These assets are accounted for as restricted cash on the Company's interim unaudited condensed consolidated balance sheets.

9. Taxes

The Company's effective tax rate was 31% in the six months ended June 30, 2016, compared with (1)% in the corresponding period in 2015. The Company's effective tax rate differed from the U.S. statutory rate of 35% primarily due to an increase in the valuation allowance, which was largely attributable to impairment losses in Brazil, as well as non-deductible local taxes, stock based compensation and a third party royalty in Colombia. These items were partially offset by the impact of foreign taxes, foreign currency translation adjustments and other permanent differences, which mainly relates to non-taxable gain arising on the acquisition of Petroamerica and uncertain tax position adjustments, partially offset by prior periods true-up adjustments and other non-deductible expenses. The deferred tax recovery for six months ended June 30, 2016, included \$53.1 million associated with the ceiling test impairment loss in Colombia.

On December 23, 2014, the Colombian Congress passed a law which imposes an equity tax levied on Colombian operations for 2015, 2016 and 2017. The equity tax is calculated based on a legislated measure, which is based on the Company's Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. This measure is subject to adjustment for inflation in future years. The equity tax rates for January 1, 2015, 2016 and 2017, are 1.15%, 1% and 0.4%, respectively. The legal obligation for each year's equity tax liability arises on January 1 of each year; therefore, the Company recognized the annual amounts of \$3.1 million and \$3.8 million, respectively, for the equity tax expense in the consolidated statement of operations during the six months ended June 30, 2016 and 2015. At June 30, 2016, accounts payable included \$1.6 million (December 31, 2015 - \$nil) which will be paid in September 2016.

10. Credit Facility

On June 2, 2016, the Company entered into a Second Amendment (the "Second Amendment") to its credit agreement dated September 18, 2015 (the "credit facility"). Pursuant to the Second Amendment, among other things, the committed borrowing base under the Company's credit facility was reduced from \$200 million to \$185 million, with \$160 million readily available and \$25 million subject to the consent of all lenders. Further, the amount of permitted senior debt under the Company's credit facility was decreased from \$600 million to \$500 million.

11. Contingencies

On June 6, 2016, the Company received a positive decision from the Chamber of Commerce of Bogotá Center for Arbitration and Conciliation tribunal (the "Tribunal") relating to its dispute with the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) of Colombia ("ANH") with respect to whether all production from the Moqueta Exploitation Area of the Chaza Block exploration and production contract ("Chaza Contract") was subject to an additional royalty (the "HPR Royalty"). In its decision, the Tribunal found that the HPR Royalty under the Chaza Contract was only payable when the

accumulated oil production from the Moqueta Exploitation Area exceeded 5.0 MMbbl. That production threshold was reached on April 30, 2015, and since that time the Company has been paying the HPR Royalty on production from the Moqueta Exploitation Area.

The 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 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 \$45.2 million as at June 30, 2016. 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.

The Company provided the purchaser of its Argentina business unit with certain indemnifications. The Company remains responsible for certain contingent liabilities related to such indemnifications, subject to defined limitations. The Company does not believe that these obligations are probable of having a material impact on its consolidated financial position, results of operations or cash flows.

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

Letters of credit

At June 30, 2016, the Company had provided promissory notes totaling \$72.4 million (December 31, 2015 - \$76.5 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

12. Financial Instruments, Fair Value Measurement, Credit Risk and Foreign Exchange Risk

Financial Instruments

At June 30, 2016, the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, trading securities, derivatives assets, accounts payable and accrued liabilities, Notes, 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 trading securities, derivative assets and RSU and PSU liabilities are being remeasured at the estimated fair value at the end of each reporting period.

The fair value of trading securities which were received as consideration on the sale of the Company's Argentina business unit is estimated based on quoted market prices in an active market.

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 trading securities, derivative assets, and RSU and PSU liabilities at June 30, 2016, and December 31, 2015, were as follows:

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(Thousands of U.S. Dollars)	As at	As at
	June 30, 2016	December 31, 2015
Trading securities	\$3,979	\$ 6,250
Commodity price derivative asset	5,896	—
Foreign currency derivative asset	1,118	—
	\$10,993	\$ 6,250
RSU and PSU liability	\$2,129	\$ 1,189

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

(Thousands of U.S. Dollars)	Three Months		Six Months	
	Ended June 30, 2016	2015	Ended June 30, 2016	2015
Trading securities loss (gain)	\$1,380	\$(1,688)	\$2,225	\$(2,100)
Commodity price derivative gain	(1,334)	—	(1,334)	—
Foreign currency derivatives (gain) loss	(1,118)	322	(1,118)	692
Financial instruments gain	\$(1,072)	\$(1,366)	\$(227)	\$(1,408)

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

The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. Financial instruments not recorded at fair value include the Notes (Note 6). At June 30, 2016, the carrying amount of the Notes was \$109.1 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was \$144.6 million. 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 June 30, 2016, and December 31, 2015, the fair value of the trading securities acquired in connection with the disposal of the Argentina business unit and the RSU liability was determined using Level 1 inputs. At June 30, 2016, the fair value of the derivative assets was determined using Level 2 inputs. The fair value of the PSU liability was determined using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of the Notes was determined using Level 2 inputs based on the indicative pricing published by certain investment banks or trading levels of the Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and restricted cash 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 June 30, 2016, the Company had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold		
			Purchased Put	Sold Put	Sold Call
Collar: June 1, 2016 to May 31, 2017	10,000	ICE Brent	\$ 35	\$ 45	\$ 65

The Company paid a premium of \$4.6 million, or \$1.25 per bbl, upon entering into the commodity price derivative. Collars are a combination of put options (floor) and sold call options (ceiling). For a collar position, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor strike price while the Company is required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor strike price and equal to or less than the ceiling strike price.

Foreign Currency Derivatives

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

At June 30, 2016, the Company had outstanding foreign currency derivative positions as follows:

Period and type of instrument	Amount hedged (COP)	Reference	Purchased/Sold		
			Call	Put	Sold Put
Collar: June 1, 2016 to June 30, 2016	9,794.6	COP	3,000	3,265	3,310
Collar: July 1, 2016 to September 30, 2016	25,064.6	COP	3,000	3,275	3,320
Collar: October 1, 2016 to December 31, 2016	20,930.0	COP	3,000	3,285	3,330
Collar: January 1, 2017 to March 31, 2017	31,597.6	COP	3,100	3,300	3,345
Collar: April 1, 2017 to May 31, 2017	22,697.2	COP	3,100	3,310	3,370
	110,084.0				

The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

While the use of these derivative instruments may limit or partially reduce the downside risk of adverse commodity price and foreign exchange movements, their use also may limit future income and gains from favorable commodity price and foreign exchange movements.

13. Supplemental Cash Flow Information

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

(Thousands of U.S. Dollars)	Six Months Ended	
	June 30, 2016	2015
Accounts receivable and other long-term assets	\$(9,156)	\$23,652
Derivatives	(4,562)	—
Inventory	4,365	(7,697)
Prepays	1,102	2,133
Accounts payable and accrued and other long-term liabilities	(5,628)	(20,319)

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Taxes receivable and payable	7,249	(44,273)
Net changes in assets and liabilities from operating activities	\$(6,630)	\$(46,504)

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The following table provides additional supplemental cash flow disclosures:

(Thousands of U.S. Dollars)	Six Months Ended June 30,	
	2016	2015
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	\$24,497	\$33,658

14. Subsequent Events

On June 30, 2016, Gran Tierra Energy International Holdings Ltd., a wholly-owned subsidiary of the Company, entered into a share purchase agreement (the "Acquisition Agreement") to acquire all of the issued and outstanding common shares of PetroLatina Energy Ltd. ("PetroLatina") for cash consideration of \$525.0 million (the "Acquisition"), subject to customary working capital and other adjustments. Funding for the Acquisition will consist of an initial payment of \$500.0 million at closing and a deferred payment of \$25.0 million to be paid prior to December 31, 2016. Subsequent to the signing of the Acquisition Agreement, the Company paid \$5.0 million, which funds are to be held in escrow and applied to the initial payment at closing. The Acquisition is also subject to customary closing conditions, including, among other things, any required regulatory approval. Approval from the ANH was received on July 29, 2016 and the Acquisition is expected to close prior to August 31, 2016.

PetroLatina is a private, independent exploration and production company, incorporated in England and Wales, with assets primarily in the Middle Magdalena Basin of Colombia. Upon completion of the transaction, PetroLatina will become an indirect wholly-owned subsidiary of Gran Tierra.

On July 8, 2016, the Company issued approximately 57.8 million subscription receipts ("Subscription Receipts") in a private placement to eligible purchasers at a price of \$3.00 per Subscription Receipt for gross proceeds of approximately \$173.5 million. Each Subscription Receipt will entitle the holder to automatically receive one common share of the Company upon closing of the Acquisition upon the satisfaction of certain conditions. The gross proceeds from the sale of the Subscription Receipts will be held in escrow until the Acquisition close date and will be recorded as restricted cash by the Company.

The Company expects to fund the Acquisition through a combination of the Company's current cash balance, gross proceeds of \$173.5 million from the Subscription Receipts, available borrowings under the Company's existing revolving loan and \$130.0 million of borrowings under a new term loan that is contingent upon the closing of the Acquisition.

The Acquisition Agreement may be terminated by either Gran Tierra or the vendors under certain circumstances set forth in the Acquisition Agreement, including, among other circumstances, the failure of the Acquisition to be consummated on or before October 31, 2016. For further information regarding the Acquisition, please see "Risk Factors - The acquisition of PetroLatina may not be completed, and even if the acquisition is completed, we may fail to realize the benefits anticipated as a result of the acquisition."

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

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language at the very beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well

as Part II, Item 1A "Risk Factors" in this Quarterly Report on Form 10-Q and Part I, Item 1A "Risk Factors" in our 2015 Annual Report on Form 10-K.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our Annual Report on Form 10-K, filed with the SEC on February 29, 2016.

Highlights

Acquisitions of Petroamerica and PGC

On January 13, 2016, we acquired all of the issued and outstanding common shares of Petroamerica, a Calgary based oil and gas exploration, development and production company active in Colombia. As consideration we issued approximately 13.7 million shares of Common Stock, and paid cash consideration of approximately \$70.6 million. The fair value of Common Stock issued was determined to be \$25.8 million based on the closing price of shares of our Common Stock on the acquisition date. Total net purchase price of Petroamerica was \$72.2 million, after giving consideration to net working capital of \$24.2 million.

The acquisition was accounted for as a business combination using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recognized at their fair values as at the acquisition date, and the results of Petroamerica were included with our results from that date. The fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. As a result, we recognized a "Gain on acquisition" of \$11.7 million in the interim unaudited condensed consolidated statement of operations for the six months ended June 30, 2016.

Additionally, on January 25, 2016, we acquired all of the issued and outstanding common shares of PGC for cash consideration. The net purchase price of PGC was \$19.4 million, after giving consideration to net working capital of \$18.3 million. PGC's working capital on the acquisition date included restricted cash of \$18.6 million and cash of \$0.2 million. Of the opening balance of restricted cash, \$15.6 million was released prior to June 30, 2016, and we expect that the remaining balance will be released this year. The acquisition was accounted for as an asset acquisition.

Convertible Senior Notes

During April 2016, we issued \$115 million aggregate principal amount of 5.00% Convertible Senior Notes due 2021 (the "Notes") in a private placement to qualified institutional buyers. Net proceeds from the sale of the Notes were \$108.9 million, after deducting the initial purchasers' discount and the offering expenses.

The Notes bear interest at a rate of 5.00% per year. Interest expense on the Notes for the three and six months ended June 30, 2016, was \$1.3 million.

The Notes are convertible at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. We may not redeem the Notes prior to April 5, 2019, except in certain circumstances following a fundamental change (as defined in the indenture governing the Notes). We may redeem for cash all or any portion of the Notes, on or after April 5, 2019, if certain conditions are met. The redemption price will be equal to 100% of the principal amount of the Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date.

If we undergo a fundamental change, holders may require us to repurchase for cash all or any portion of their Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

PetroLatina Acquisition Agreement

On June 30, 2016, Gran Tierra Energy International Holdings Ltd., a wholly-owned subsidiary of the Company, entered into a share purchase agreement (the "Acquisition Agreement") to acquire all of the issued and outstanding common shares of PetroLatina for cash consideration of \$525.0 million (the "Acquisition"), subject to customary working capital and other adjustments. Funding for the Acquisition will consist of an initial payment of \$500.0 million at closing and a deferred payment of \$25.0 million to be paid prior to December 31, 2016. Subsequent to the signing of the Acquisition Agreement, we paid \$5.0

million, which funds are to be held in escrow and applied to the initial payment at closing. The Acquisition is also subject to customary closing conditions, including, among other things, any required regulatory approval. Approval from the ANH was received on July 29, 2016 and the Acquisition is expected to close prior to August 31, 2016.

PetroLatina is a private, independent exploration and production company with assets primarily in the Middle Magdalena basin of Colombia. We expect the acquisition to close in the second half of 2016 subject to various factors, including the timing of shareholder and regulatory approvals. Upon completion of the transaction, PetroLatina will become an indirect wholly-owned subsidiary of Gran Tierra.

On July 8, 2016, we issued approximately 57.8 million subscription receipts (the “Subscription Receipts”) in a private placement to eligible purchasers at a price of \$3.00 per Subscription Receipt for gross proceeds of approximately \$173.5 million. Each Subscription Receipt will entitle the holder to automatically receive one common share of Gran Tierra upon closing of the Acquisition upon the satisfaction of certain conditions.

We expect to fund the Acquisition through a combination of our current cash balance, gross proceeds of \$173.5 million from the Subscription Receipts, available borrowings under our existing revolving loan and \$130.0 million of borrowings under a new term loan that is contingent upon the closing of the Acquisition. For further information regarding the Acquisition, please see “Risk Factors - The acquisition of PetroLatina may not be completed, and even if the acquisition is completed, we may fail to realize the benefits anticipated as a result of the acquisition.”

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	Three Months Ended March 31,				Six Months Ended June 30,		
	2016	2016	2015	% Change	2016	2015	% Change
Volumes (BOE)							
Working Interest Production Before Royalties	2,330,539	2,342,681	2,101,499	11	4,673,221	4,262,831	10
Royalties	(256,803)	(368,384)	(418,508)	(12)	(625,188)	(767,283)	(19)
Production NAR	2,073,736	1,974,297	1,682,991	17	4,048,033	3,495,548	16
Decrease (Increase) in Inventory Sales ⁽¹⁾	240,424	65,753	(320,768)	(120)	306,175	(387,422)	(179)
	2,314,160	2,040,050	1,362,223	50	4,354,208	3,108,126	40
Average Daily Volumes (BOEPD)							
Working Interest Production Before Royalties	25,610	25,744	23,094	11	25,677	23,552	9
Royalties	(2,822)	(4,049)	(4,600)	(12)	(3,435)	(4,240)	(19)
Production NAR	22,788	21,695	18,494	17	22,242	19,312	15
Decrease (Increase) in Inventory Sales ⁽¹⁾	2,642	723	(3,524)	(121)	1,682	(2,140)	(179)
	25,430	22,418	14,970	50	23,924	17,172	39
Operating Netback (\$000s)							
Oil and Natural Gas Sales	\$57,403	\$71,713	\$69,350	3	\$129,116	\$145,581	(11)
Operating Expenses	(19,067)	(17,748)	(17,758)	—	(36,815)	(40,419)	(9)
Transportation Expenses	(12,328)	(6,217)	(6,375)	(2)	(18,545)	(15,148)	22
Operating Netback ⁽²⁾	\$26,008	\$47,748	\$45,217	6	\$73,756	\$90,014	(18)
General and Administrative Expenses ("G&A") (\$000s)							
	\$8,286	\$7,975	\$10,298	(23)	\$16,261	\$17,592	(8)
Net Loss (\$000s)							
	\$(45,032)	\$(63,559)	\$(38,564)	65	\$(108,591)	\$(83,430)	30
EBITDA (\$000s) ⁽³⁾							
	\$24,184	\$40,532	\$31,710	28	\$64,716	\$73,067	(11)
Adjusted EBITDA (\$000s) ⁽³⁾							
	\$13,257	\$41,313	\$34,679	19	\$54,570	\$64,498	(15)
Net cash provided by operating activities (\$000s)							
	\$10,812	\$27,412	\$3,223	751	\$38,224	\$5,568	586
Funds Flow From Operations (\$000s) ⁽⁴⁾							
	\$11,563	\$33,755	\$25,040	35	\$45,318	\$54,036	(16)
Capital Expenditures (\$000s)							
	\$26,180	\$18,407	\$17,872	3	\$44,587	\$91,318	(51)
As at							
June 30, 2016							
December 31, 2015							
				% Change			
Cash, Cash Equivalents and Current Restricted Cash (\$000s)	\$181,186	\$145,434		25			
Working Capital (\$000s)		\$210,815	\$160,449	31			

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

Non-GAAP measures

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

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

(3) EBITDA, as presented, is net loss adjusted for depletion, depreciation and accretion (“DD&A”) expenses, asset impairment, interest expense and income tax recovery or expense. Adjusted EBITDA is EBITDA adjusted for gain on acquisition and foreign exchange losses or gains. 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 loss to EBITDA and adjusted EBITDA is as follows:

	Three Months Ended March 31, 2016	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
EBITDA - Non-GAAP Measure (\$000s)	2016	2016	2015	2016	2015
Net loss	\$(45,032)	\$(63,559)	\$(38,564)	\$(108,591)	\$(83,430)
Adjustments to reconcile net loss to EBITDA					
DD&A expenses	36,912	31,884	39,188	68,796	88,328
Asset impairment	56,898	92,843	30,285	149,741	67,299
Income tax (recovery) expense	(25,113)	(22,837)	801	(47,950)	870
Interest expense	519	2,201	—	2,720	—
EBITDA	24,184	\$40,532	\$31,710	64,716	73,067
Gain on acquisition	(11,712)	—	—	(11,712)	—
Foreign exchange loss (gain)	785	781	2,969	1,566	(8,569)
Adjusted EBITDA	\$13,257	\$41,313	\$34,679	\$54,570	\$64,498

(4) Funds flow from operations, as presented, is net cash provided by operating activities adjusted for net change in assets and liabilities from operating activities and cash settlement of asset retirement obligation. During the three months ended September 30, 2015, we changed our method of calculating funds flow from operations to be more consistent with our peers. Funds flow from operations is no longer net of cash settlement of asset retirement obligation. Additionally, foreign exchange gains and losses on cash and cash equivalents have been excluded from funds flow. Comparative information has been restated to be calculated on a consistent basis. Management uses this financial measure to analyze liquidity and cash flows generated by our principal business activities prior to the consideration of how changes in assets and liabilities from operating activities and cash settlement of asset retirement obligation affect those cash flows, and believes that this financial measure is also useful supplemental information for investors to analyze our liquidity and financial results. A reconciliation from net cash provided by operating activities to funds flow from operations is as follows:

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	Three Months Ended March 31, 2016	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Funds Flow From Operations - Non-GAAP Measure (\$000s)					
Net cash provided by operating activities	\$10,812	\$27,412	\$3,223	38,224	\$5,568
Adjustments to reconcile net cash provided by operating activities to funds flow from operations					
Net change in assets and liabilities from operating activities	647	5,983	21,278	6,630	46,504
Cash settlement of asset retirement obligation	104	360	539	464	1,964
Funds flow from operations	\$11,563	\$33,755	\$25,040	\$45,318	\$54,036

Consolidated Results of Operations

	Three Months Ended March 31,		Three Months Ended June 30,		Six Months Ended June 30,		% Change
	2016	2016	2015	% Change	2016	2015	
(Thousands of U.S. Dollars)							
Oil and natural gas sales	\$57,403	\$71,713	\$69,350	3	\$129,116	\$145,581	(11)
Operating expenses	19,067	17,748	17,758	—	36,815	40,419	(9)
Transportation expenses	12,328	6,217	6,375	(2)	18,545	15,148	22
Operating netback ⁽¹⁾	26,008	47,748	45,217	6	73,756	90,014	(18)
DD&A expenses	36,912	31,884	39,188	(19)	68,796	88,328	(22)
Asset impairment	56,898	92,843	30,285	207	149,741	67,299	123
G&A expenses	8,286	7,975	10,298	(23)	16,261	17,592	(8)
Severance expenses	1,018	281	1,988	(86)	1,299	6,366	(80)
Equity tax	3,051	—	—	—	3,051	3,769	(19)
Foreign exchange loss (gain)	785	781	2,969	(74)	1,566	(8,569)	118
Financial instruments loss (gain)	845	(1,072)	(1,366)	(22)	(227)	(1,408)	84
	107,795	132,692	83,362	59	240,487	173,377	39
Gain on acquisition	11,712	—	—	—	11,712	—	—
Interest expense	(519)	(2,201)	—	—	(2,720)	—	—
Interest income	449	749	382	96	1,198	803	49
Loss before income taxes	(70,145)	(86,396)	(37,763)	129	(156,541)	(82,560)	90
Current income tax expense	(2,023)	(5,778)	(5,684)	2	(7,801)	(8,109)	(4)
Deferred income tax recovery	27,136	28,615	4,883	486	55,751	7,239	670
	25,113	22,837	(801)	—	47,950	(870)	—
Net loss	\$(45,032)	\$(63,559)	\$(38,564)	65	\$(108,591)	\$(83,430)	30
Sales Volumes ⁽²⁾							
Oil and NGL's, bbl	2,292,116	2,020,722	1,349,127	50	4,312,836	3,084,025	40
Natural gas, Mcf	132,265	115,968	78,578	48	248,233	144,605	72
Total sales volumes, BOE	2,314,160	2,040,050	1,362,223	50	4,354,208	3,108,126	40
Total sales volumes, BOEPD	25,430	22,418	14,970	50	23,924	17,172	39
Average Prices							
Oil and NGL's per bbl	\$24.88	\$35.31	\$51.18	(31)	\$29.77	\$47.03	(37)

Natural gas per Mcf	\$2.83	\$3.06	\$3.78	(19)	\$2.94	\$3.82	(23)
Brent Price per bbl	\$33.70	\$45.52	\$61.70	(26)	\$39.61	\$57.81	(31)
Consolidated Results of Operations per BOE sales volumes							
Oil and natural gas sales	\$24.81	\$35.15	\$50.91	(31)	\$29.65	\$46.84	(37)
Operating expenses	8.24	8.70	13.04	(33)	8.46	13.00	(35)
Transportation expenses	5.33	3.05	4.68	(35)	4.26	4.88	(13)
Operating netback ⁽¹⁾	11.24	23.40	33.19	(29)	16.93	28.96	(42)
DD&A expenses	15.95	15.63	28.77	(46)	15.80	28.42	(44)
Asset impairment	24.59	45.51	22.23	105	34.39	21.65	59
G&A expenses	3.58	3.91	7.56	(48)	3.73	5.66	(34)
Severance expenses	0.44	0.14	1.46	(90)	0.30	2.05	(85)
Equity tax	1.32	—	—	—	0.70	1.21	(42)
Foreign exchange loss (gain)	0.34	0.38	2.18	83	0.36	(2.76)	113
Financial instruments loss (gain)	0.37	(0.53)	(1.00)	(47)	(0.05)	(0.45)	89
	46.59	65.04	61.20	6	55.23	55.78	(1)
Gain on acquisition	5.06	—	—	—	2.69	—	—
Interest expense	(0.22)	(1.08)	—	—	(0.62)	—	—
Interest income	0.19	0.37	0.28	32	0.28	0.26	8
Loss before income taxes	(30.32)	(42.35)	(27.73)	53	(35.95)	(26.56)	35
Current income tax expense	(0.87)	(2.83)	(4.17)	(32)	(1.79)	(2.61)	(31)
Deferred income tax recovery	11.73	14.03	3.58	292	12.80	2.33	449
	10.86	11.20	(0.59)	—	11.01	(0.28)	—
Net loss	\$(19.46)	\$(31.15)	\$(28.32)	10	\$(24.94)	\$(26.84)	(7)

⁽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.

⁽²⁾ Sales volumes represent production NAR adjusted for inventory changes and losses.

Oil and gas production and sales volumes, BOEPD

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015		
	Colombia	Brazil	Total	Colombia	Brazil	Total
Average Daily Volumes (BOEPD)						
Working Interest Production Before Royalties	24,818	926	25,744	22,601	493	23,094
Royalties	(3,921)	(128)	(4,049)	(4,531)	(69)	(4,600)
Production NAR	20,897	798	21,695	18,070	424	18,494
Decrease (Increase) in Inventory	713	10	723	(3,503)	(21)	(3,524)
Sales	21,610	808	22,418	14,567	403	14,970
Royalties, % of Working Interest Production Before Royalties	16	% 14	% 16	% 20	% 14	% 20
	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
	Colombia	Brazil	Total	Colombia	Brazil	Total
Average Daily Volumes (BOEPD)						
Working Interest Production Before Royalties	24,852	825	25,677	22,947	605	23,552
Royalties	(3,298)	(137)	(3,435)	(4,157)	(83)	(4,240)
Production NAR	21,554	688	22,242	18,790	522	19,312
Decrease (Increase) in Inventory	1,680	2	1,682	(2,145)	5	(2,140)
Sales	23,234	690	23,924	16,645	527	17,172
Royalties, % of Working Interest Production Before Royalties	13	% 17	% 13	% 18	% 14	% 18

Oil and gas production NAR for the three and six months ended June 30, 2016, increased by 17% to 21,695 BOEPD and increased by 15% to 22,242 BOEPD, respectively, compared with 18,494 and 19,312 BOEPD, respectively, in the corresponding periods in 2015. In the three and six months ended June 30, 2016, production increased primarily due to the acquisition of Petroamerica and the drilling program in the Costayaco and Moqueta Fields in Colombia. Royalties as a percentage of production decreased from the prior year commensurate with the decrease in oil prices. During the six months ended June 30, 2016, due to the low price environment we elected to defer a number of workovers in Costayaco and Moqueta until the second half of 2016. In the corresponding periods in Brazil in 2015, our operations in the Tiê Field were temporarily suspended by the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") from March 11, 2015, to May 15, 2015.

Oil and gas production NAR for the three months ended June 30, 2016, decreased by 5% compared with the prior quarter. As noted above, we deferred our workover program until the second half of 2016. In the first quarter of 2016, our production in Brazil was limited by a temporary capacity reduction at a third party's shipping facility due to an integrity issue with one of their oil receiving tanks. The third party operator completed repairs on the facility and the tank was fully operational as of March 21, 2016. Receiving capacity for the field's crude oil is now restored to 1,100 bopd.

Oil and gas sales volumes for the three and six months ended June 30, 2016, increased by 50% to 22,418 BOEPD, and increased by 39% to 23,924 BOEPD, respectively, compared with 14,970 BOEPD and 17,172 BOEPD, respectively, in the corresponding periods in 2015. Sales volumes increased due to higher working interest production (2,650 and 2,125 BOEPD respectively), lower royalty volumes (551 and 805 BOEPD respectively) and decreased inventory (4,247 and 3,822 BOEPD respectively). During the three months ended June 30, 2016, oil inventory decreases accounted for 0.1 MMbbl or 723 bopd of increased sales volumes compared with oil inventory increases which accounted for 0.3 MMbbl or 3,524 bopd of reduced sales volumes in the corresponding period in 2015. During the six months ended June 30, 2016, oil inventory decreases accounted for 0.3 MMbbl or 1,682 bopd of increased sales volumes compared with oil inventory increases which accounted for 0.4 MMbbl or 2,140 bopd of reduced sales volumes in the corresponding period in 2015.

Oil and gas sales for the three months ended June 30, 2016, decreased by 12% to 22,418 BOEPD compared with 25,430 BOEPD in the prior quarter. Sales volumes decreased due to the effect of inventory changes (1,919 BOEPD) and higher royalty volumes (1,227 BOEPD), partially offset by higher working interest production (134 BOEPD).

Operating netbacks

	Three Months Ended June 30, 2016			Three Months Ended June 30, 2015		
(Thousands of U.S. Dollars)	Colombia	Brazil	Total	Colombia	Brazil	Total
Oil and Gas Sales	\$69,271	\$2,442	\$71,713	\$67,627	\$1,723	\$69,350
Transportation Expenses	(6,105)	(112)	(6,217)	(6,348)	(27)	(6,375)
	63,166	2,330	65,496	61,279	1,696	62,975
Operating Expenses	(16,994)	(754)	(17,748)	(14,921)	(2,837)	(17,758)
Operating Netback ⁽¹⁾	\$46,172	\$1,576	\$47,748	\$46,358	\$(1,141)	\$45,217

U.S. Dollars Per BOE

Brent		\$45.52		\$61.70
WTI		\$45.59		\$57.87

Oil and Gas Sales	\$35.23	\$33.20	\$35.15	\$51.02	\$46.92	\$50.91
Transportation Expenses	(3.10)	(1.52)	(3.05)	(4.79)	(0.74)	(4.68)
	32.13	31.68	32.1	46.23	46.18	46.23
Operating Expenses	(8.64)	(10.25)	(8.70)	(11.26)	(77.26)	(13.04)
Operating Netback ⁽¹⁾	\$23.49	\$21.43	\$23.40	\$34.97	\$(31.08)	\$33.19

	Six Months Ended June 30, 2016			Six Months Ended June 30, 2015		
(Thousands of U.S. Dollars)	Colombia	Brazil	Total	Colombia	Brazil	Total
Oil and Natural Gas Sales	\$125,571	\$3,545	\$129,116	\$141,694	\$3,887	\$145,581
Transportation Expenses	(18,361)	(184)	(18,545)	(15,030)	(118)	(15,148)
	107,210	3,361	110,571	126,664	3,769	130,433
Operating Expenses	(36,158)	(657)	(36,815)	(36,213)	(4,206)	(40,419)
Operating Netback ⁽¹⁾	\$71,052	\$2,704	\$73,756	\$90,451	\$(437)	\$90,014

U.S. Dollars Per bbl

Brent		\$39.61		\$57.81
WTI		\$39.52		\$53.25

U.S. Dollars Per BOE

Oil and Natural Gas Sales	\$29.70	\$28.19	\$29.65	\$47.03	\$40.77	\$46.84
Transportation Expenses	(4.34)	(1.46)	(4.26)	(4.99)	(1.24)	(4.88)
	25.36	26.73	25.39	42.04	39.53	41.96
Operating Expenses	(8.55)	(5.22)	(8.46)	(12.02)	(44.12)	(13.00)
Operating Netback ⁽¹⁾	\$16.81	\$21.51	\$16.93	\$30.02	\$(4.59)	\$28.96

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

Oil and gas sales for the three months ended June 30, 2016, increased by 3% to \$71.7 million from \$69.4 million in the comparable period in 2015. The effect of decreased realized oil prices was more than offset by higher sales volumes. Oil and gas sales for the six months ended June 30, 2016, decreased by 11% to \$129.1 million from \$145.6 million in the comparable period in 2015 primarily due to the effect of decreased realized oil prices, partially offset by higher sales volumes.

Average realized prices for the three and six months ended June 30, 2016, decreased by 31% to \$35.15 per BOE, and by 37% to \$29.65 per BOE, respectively, from \$50.91 and \$46.84 per BOE, respectively, in the corresponding periods in 2015. These price decreases were primarily due to lower benchmark oil prices. Average Brent oil prices for the three and six months ended June 30, 2016, decreased by 26% to \$45.52 per bbl, and by 31% to \$39.61 per bbl, respectively, compared with \$61.70 and

\$57.81 per bbl, respectively, in the corresponding periods in 2015. Average WTI oil prices for the three and six months ended June 30, 2016, decreased by 21% to \$45.59 and by 26% to \$39.52 per bbl, respectively, compared with \$57.87 and \$53.25 per bbl, respectively, in the corresponding periods in 2015.

During periods of OTA pipeline disruptions, we have multiple transportation alternatives. Each transportation route has varying effects on realized prices and transportation costs. During the three and six months ended June 30, 2016, 47% and 49%, respectively, of our oil volumes sold in Colombia were sold through the OTA pipeline compared with 75% and 78%, respectively, in the corresponding periods in 2015. Sales during the six months ended June 30, 2016, reflected an inventory decrease in Ecuador of 270 Mbbbl.

Oil and gas sales for the three months ended June 30, 2016, increased by 25% to \$71.7 million from \$57.4 million compared with the prior quarter primarily due to higher realized prices, partially offset by lower sales volumes. Average realized prices increased by 42% to \$35.15 per BOE for the three months ended June 30, 2016, compared with \$24.81 per BOE in the prior quarter, primarily due to higher benchmark oil prices. Average Brent oil prices for the three months ended June 30, 2016, were \$45.52 per bbl, compared with \$33.70 per bbl, in the prior quarter, a 35% increase. During the prior quarter, 54% of our oil volumes sold in Colombia were sold through the OTA pipeline compared with 47% in the current quarter.

Transportation expenses for the three months ended June 30, 2016 decreased by 2% to \$6.2 million compared with the corresponding period in 2015. The decrease was due to decreased transportation expenses per BOE, partially offset by higher sales volumes. On a per BOE basis, transportation expenses decreased by 35% to \$3.05 per BOE from \$4.68 per BOE in the corresponding period in 2015. The decrease was a result of trucking more barrels due to higher realized sales prices.

Transportation expenses for the six months ended June 30, 2016, increased by 22% to \$18.5 million compared with the corresponding period in 2015. The increase in the six months ended June 30, 2016 was due to decreased transportation expenses per BOE being more than offset by higher sales volumes. On a per BOE basis, transportation expenses decreased by 13% to \$4.26 per BOE from \$4.88 per BOE in the corresponding period in 2015. The decrease was primarily due to the alternative transportation routes used during periods of OTA pipeline disruptions.

Transportation expenses for the three months ended June 30, 2016, decreased 50% to \$6.2 million compared to \$12.3 million in the prior quarter. The effect of decreased transportation costs per BOE combined with lower sales volumes. On a per BOE basis, transportation expenses decreased by 43% to \$3.05 per BOE from \$5.33 per BOE in the prior quarter. The decrease was primarily due to a higher percentage of sales at the wellhead, 48% in the three months ended June 30, 2016, compared with 33% in the prior quarter.

Operating expenses for the three and six months ended June 30, 2016, were comparable at \$17.7 million and decreased by 9% to \$36.8 million, compared with the corresponding periods in 2015. The decrease was primarily due to decreased operating costs per BOE, partially offset by higher sales volumes. On a per BOE basis, operating expenses decreased by 33% to \$8.70 per BOE from \$13.04 per BOE and decreased by 35% to \$8.46 per BOE from \$13.00 per BOE, in the corresponding periods in 2015.

In Colombia, operating costs for the three and six months ended June 30, 2016 decreased by \$2.62 per BOE and \$3.47 per BOE compared with the corresponding periods in 2015, primarily as a result of cost saving measures.

In Brazil in the six months ended June 30, 2016, we reduced the value of a contingent loss by \$0.4 million, or \$3.31 per bbl based on volumes sold in Brazil, after we settled a one-time penalty for less than we had estimated. The one-time penalty related to alleged non-compliance with certain requirements regarding the health and safety management system, identified during a safety and operational audit conducted by the ANP in early 2015.

Additionally, in Brazil operating costs per BOE decreased as a result of a reduction in headcount, partially offset by the effect of the weakening the U.S. dollar against the local currency in Brazil, which resulted in higher costs for costs denominated in local currency.

Operating expenses decreased by 7% to \$17.7 million in the three months ended June 30, 2016, compared with \$19.1 million in the prior quarter primarily due to lower sales volumes, partially offset by the effect of increased operating costs per BOE. On a per BOE basis, operating expenses increased by 6% to \$8.70 per BOE for the three months ended June 30, 2016, from \$8.24 per BOE in the prior quarter. Due to low commodity prices in the first half of 2016, we deferred multiple workovers until the second half of 2016. Whilst there is an impact on working interest production, we believe we will maximize returns by electing to defer workovers.

DD&A expenses

	Three Months Ended June 30, 2016		Three Months Ended June 30, 2015	
	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, thousands of U.S. Dollars Per BOE	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, thousands of U.S. Dollars Per BOE
Colombia	\$30,458	\$ 15.49	\$37,061	\$ 27.96
Brazil	1,024	13.92	1,575	42.89
Peru	71	—	147	—
Corporate	331	—	405	—
	\$31,884	\$ 15.63	\$39,188	\$ 28.77

	Six Months Ended June 30, 2016		Six Months Ended June 30, 2015	
	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, thousands of U.S. Dollars Per BOE	DD&A expenses, thousands of U.S. Dollars	DD&A expenses, thousands of U.S. Dollars Per BOE
Colombia	\$66,194	\$ 15.65	\$83,316	\$ 27.65
Brazil	1,742	13.85	3,836	40.24
Peru	212	—	414	—
Corporate	648	—	762	—
	\$68,796	\$ 15.80	\$88,328	\$ 28.42

DD&A expenses for the three and six months ended June 30, 2016, decreased to \$31.9 million (\$15.63 per BOE) and \$68.8 million (\$15.80 per BOE) from \$39.2 million (\$28.77 per BOE) and \$88.3 million (\$28.42 per BOE) in the corresponding periods in 2015. 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 decreased by 2% to \$15.63 per BOE for the three months ended June 30, 2016, from \$15.95 per BOE in the prior quarter.

Asset impairment

We follow the full cost method of accounting for our oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated “ceiling”. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year and it should not be assumed that estimates of future net revenues represent the fair market value of our reserves. In accordance with GAAP, we used an average Brent price of \$44.48 per bbl for the purposes of the June 30, 2016, ceiling test calculations (March 31, 2016 - \$48.79; December 31, 2015 - \$54.08).

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(Thousands of U.S. Dollars)	Three Months		Six Months	
	Ended June 30,		Ended June 30,	
	2016	2015	2016	2015
Impairment of oil and gas properties				
Colombia	\$78,208	\$—	\$132,776	\$—
Brazil	14,152	25,000	15,402	29,333
Peru	483	5,285	899	37,966
	\$92,843	\$30,285	\$149,077	\$67,299
Impairment of inventory	—	—	664	—
	\$92,843	\$30,285	\$149,741	\$67,299

In the three and six months ended June 30, 2016, and 2015, ceiling test impairment losses in our Colombia and Brazil cost centers and inventory impairment were primarily due to lower oil prices. Impairment losses in our Peru cost center related to costs incurred on Block 95.

G&A expenses

	Three Months Ended March 31,	Three Months Ended June 30,			Six Months Ended June 30,		
(Thousands of U.S. Dollars)	2016	2016	2015	% Change	2016	2015	% Change
G&A Expenses	\$ 8,286	\$ 7,975	\$ 10,298	(23)	\$ 16,261	\$ 17,592	(8)

U.S. Dollars Per BOE

G&A Expenses	\$ 3.58	\$ 3.91	\$ 7.56	(48)	\$ 3.73	\$ 5.66	(34)
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G&A expenses before stock-based compensation and capitalized G&A and overhead recoveries for the three and six months ended June 30, 2016, decreased by 15% to \$14.8 million and by 25% to \$28.3 million, respectively, from \$17.3 million and \$37.6 million, respectively, in the corresponding periods in 2015 as a result of reductions in the number of our employees, commitment to cost control including focusing on all of our other G&A expenses, and the effect of the stronger U.S. dollar against the local currency in Colombia and Canada during the three months ended June 30, 2016, compared with the corresponding period in 2015 which resulted in savings for costs denominated in local currency. G&A expenses in the six months ended June 30, 2016, included \$1.3 million of costs relating to the acquisition of Petroamerica.

After stock-based compensation and capitalized G&A and overhead recoveries, G&A expenses for the three and six months ended June 30, 2016, decreased by 23% to \$8.0 million (\$3.91 per BOE) and by 8% to \$16.3 million (\$3.73 per BOE), respectively, from \$10.3 million (\$7.56 per BOE) and \$17.6 million (\$5.66 per BOE), respectively, in the corresponding periods in 2015. The decrease was mainly due to the cost control initiatives referred to above, partially offset by lower allocations to capital projects due to lower capital activity. Additionally, G&A expenses in the corresponding six month period in 2015 were net of a credit of \$1.7 million relating to the reversal of stock-based compensation expense for unvested stock options and RSUs associated with terminated employees.

G&A expenses for the three months ended June 30, 2016, decreased by 4% to \$8.0 million (\$3.91 per BOE) compared with \$8.3 million (\$3.58 per BOE) in the prior quarter. The decrease was primarily due to higher allocations to recoveries and capital projects, partially offset by an increase in the number of our employees and higher stock-based compensation expense.

Severance expenses

For the three and six months ended June 30, 2016, severance expenses were \$0.3 million and \$1.3 million, compared with \$2.0 million and \$6.4 million in the corresponding periods in 2015. Severance expenses were consistent with the decrease in headcount.

Equity tax expense

For the six months ended June 30, 2016, and 2015 equity tax expense of \$3.1 million and \$3.8 million, respectively, represented a Colombian tax which was calculated based on our Colombian legal entities' balance sheet equity for tax purposes at January 1. The legal obligation for each year's equity tax liability arises on January 1 of each year, therefore, we recognized the annual amounts of the equity tax expense in our interim unaudited condensed consolidated statement of operations during the six months ended June 30, 2016, and 2015. No equity tax expense was recorded in the three months ended June 30, 2016 and 2015.

Foreign exchange gains and losses

For the three and six months ended June 30, 2016, we had foreign exchange losses of \$0.8 million and \$1.6 million, respectively, compared with a foreign exchange loss of \$3.0 million and gain of \$8.6 million, respectively, in the corresponding periods in 2015. 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 six months ended June 30, 2016, and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Change in the U.S. dollar against the Colombian peso	weakened by 4%	strengthened by 0.4%	weakened by 7%	strengthened by 8%

Financial instrument gains and losses

(Thousands of U.S. Dollars)	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
Trading securities loss (gain)	\$1,380	\$(1,688)	\$2,225	\$(2,100)
Commodity price derivative gain	(1,334)	—	(1,334)	—
Foreign currency derivatives (gain) loss	(1,118)	322	(1,118)	692
	\$(1,072)	\$(1,366)	\$(227)	\$(1,408)

Trading securities gains and losses related to unrealized gain and losses on the Madalena Energy Inc. shares we received in connection with the sale of our Argentina business unit in June 2014.

During the three months ended June 30, 2016, we entered into commodity price derivative contracts to manage the variability 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. We also entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs. In 2015, foreign currency derivative gains and losses related to our Colombian peso non-deliverable forward contracts which were purchased for purposes of fixing the exchange rate at which we would purchase or sell Colombian pesos to settle our income tax installments and payments.

Income tax expense and recovery

For the three and six months ended June 30, 2016, income tax recovery was \$22.8 million and \$48.0 million, respectively, compared with income tax expense of \$0.8 million and \$0.9 million, respectively, in the corresponding periods in 2015. The income tax recovery for the three and six months ended June 30, 2016, was primarily due to ceiling test impairment losses in Colombia. The income tax recovery for the three and six months ended June 30, 2016, included \$31.3 million and \$53.1 million, respectively, associated with ceiling test impairment losses in Colombia. In the three and six months ended June 30, 2015, income tax recovery associated with impairment losses in Peru and Brazil was offset by a full valuation allowance.

The effective tax rate was 31% in the six months ended June 30, 2016, compared with (1)% in the corresponding period in 2015. The change in the effective tax rate for the six months ended June 30, 2016, was primarily due to decreases in the valuation allowance, the impact of foreign taxes, foreign currency translation adjustments and other permanent differences.

For the six months ended June 30, 2016, the difference between the effective tax rate of 31% and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance, which was largely attributable to impairment losses in Brazil, as well as non-deductible local taxes, stock based compensation and a third-party royalty in Colombia. These items were partially offset by the impact of foreign taxes, foreign currency translation adjustments

and other permanent differences, which mainly relates to non-taxable gain arising on the acquisition of Petroamerica and uncertain tax position adjustments, partially offset by prior periods true-up adjustments and other non-deductible expenses. For the six months ended June 30, 2015, the difference between the effective tax rate of (1)% and the 35% U.S. statutory rate was primarily due to other local taxes, an increase in the valuation allowance and the non-deductible third party royalty in Colombia, which were partially offset by the impact of foreign taxes and other permanent differences.

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

For the three and six months ended June 30, 2016, funds flow from operations increased by 35% to \$33.8 million and decreased by 16% to \$45.3 million, respectively, compared with the corresponding periods in 2015.

For the three months ended June 30, 2016, our funds flow from operations increased due to increased oil and natural gas sales, lower transportation, G&A, severance, lower realized foreign exchange losses of \$0.5 million, compared with \$2.5 million in the corresponding period and the absence of cash settlement of financial instruments, were partially offset by higher interest expenses.

For the six months ended June 30, 2016, our funds flow from operations was negatively impacted by equity tax of \$3.1 million, realized foreign exchange losses of \$1.5 million, transaction costs of \$1.3 million and severance expenses of \$1.3 million. Lower oil and natural gas sales, higher transportation and interest expenses and realized foreign exchange losses, were partially offset by lower operating, G&A, severance, equity tax and income tax expenses and the absence of cash settlement of financial instruments.

2016 Capital Program

On May 31, 2016, we announced an increase to our 2016 capital budget of \$33 million to \$43 million for a revised total of \$140 million to \$150 million. Our previously announced base capital budget was \$107 million. We expect that the increased capital budget will be entirely directed towards exploration in Colombia. We expect to finance our 2016 capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions.

Capital expenditures for the six months ended June 30, 2016, were \$44.6 million compared with \$91.3 million for the six months ended June 30, 2015. In the six months ended June 30, 2016, 82% of our capital expenditures were incurred in Colombia.

Capital Expenditures - Colombia

Capital expenditures in our Colombian segment during the three months ended June 30, 2016, were \$14.5 million. The significant elements of our second quarter 2016 capital program in Colombia were:

On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Moqueta 22 development well, which was completed as an oil producer. We also commenced civil works for the Cumplidor-1 well on the Putumayo-7 Block (100% WI, operated).

We continued facilities work at the Moqueta Field on the Chaza Block.

Capital Expenditures – Brazil

Capital expenditures in our Brazilian segment during the three months ended June 30, 2016, were \$2.2 million. In the second quarter of 2016, we completed a workover on the 1-GTE-7HPC-BA well to assess potential as a water source well.

Capital Expenditures – Peru

Capital expenditures in our Peruvian segment for the three months ended June 30, 2016, were \$1.1 million, and included \$0.3 million on Block 95 and \$0.8 million on our other blocks in Peru. In the second quarter of 2016, operations in Peru continued to focus on maintaining tangible asset integrity and security of our five blocks in Peru (95, 107 and 133, 123 and 129) and moving forward with environmental approvals on Blocks 107 and 133 (100% WI,

operated).

Liquidity and Capital Resources

At June 30, 2016, we had working capital of \$210.8 million compared with \$160.4 million at December 31, 2015. Working capital included cash and cash equivalents of \$171.5 million and restricted cash of \$9.7 million, compared with \$145.3 million of cash and cash equivalents and restricted cash of \$0.1 million at December 31, 2015.

We believe that our cash resources, including cash on hand and cash generated from operations, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2016, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank in interest earning current accounts or are 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.

Notes

On April 6, 2016, we issued \$115.0 million aggregate principal amount of our Notes in a private placement to qualified institutional buyers. The Notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October 1, 2016. The Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted.

The Notes are convertible at the option of the holder at any time prior to the close of business on the business day immediately preceding the maturity date. The conversion rate is initially 311.4295 shares of Common Stock per \$1,000 principal amount of Notes (equivalent to an initial conversion price of approximately \$3.21 per share of Common Stock). The conversion rate is subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date, we will increase the conversion rate for a holder who elects to convert its Notes in connection with such a corporate event in certain circumstances.

We may not redeem the Notes prior to April 5, 2019, except in certain circumstances following a fundamental change as defined in the indenture governing the Notes). We may redeem for cash all or any portion of the Notes, at our option, on or after April 5, 2019, if (terms used below are as defined in the indenture governing the Notes):

- (i) the last reported sale price of our Common Stock has been at least 150% of the conversion price then in effect for at least 20 trading days (whether or not consecutive) during any 30 consecutive trading day period (including the last trading day of such period) ending on, and including, the trading day immediately preceding the date on which we provide notice of redemption; and
- (ii) we have filed all reports that we are required to file with the SEC pursuant to Section 13 or 15(d) of the Exchange Act, as applicable (other than current reports on Form 8-K), during the twelve months preceding the date on which we provide such notice.

The redemption price will be equal to 100% of the principal amount of the Notes to be redeemed, plus accrued and unpaid interest, if any, to, but excluding, the redemption date. No sinking fund is provided for the Notes.

If we undergo a fundamental change, holders may require us to repurchase for cash all or any portion of their Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

PetroLatina Acquisition Agreement

As disclosed above, on June 30, 2016, Gran Tierra Energy International Holdings Ltd., a wholly-owned subsidiary of the Company, entered into the Acquisition Agreement to acquire all of the issued and outstanding common shares of PetroLatina for cash consideration of \$525.0 million, subject to customary working capital and other adjustments. Funding for the Acquisition will consist of an initial payment of \$500 million at closing and a deferred payment of \$25.0 million to be paid prior to December 31, 2016. The Acquisition is also subject to customary closing conditions, including, among other things, any required regulatory approval. Approval from the ANH was received on July 29, 2016 and the Acquisition is expected to close prior to August 31, 2016.

On July 8, 2016, we issued approximately 57.8 million Subscription Receipts in a private placement to eligible purchasers at a price of \$3.00 per Subscription Receipt for gross proceeds of approximately \$173.5 million. Each Subscription Receipt will entitle the holder to automatically receive one common share of Gran Tierra upon closing of the Acquisition upon the satisfaction of certain conditions. The gross proceeds from the sale of the Subscription Receipts will be held in escrow until the Acquisition close date and will be recorded as restricted cash by the Company.

We expect to fund the Acquisition through a combination of our current cash balance, gross proceeds of \$173.5 million from the Subscription Receipts, available borrowings under our existing revolving loan and \$130.0 million of borrowings under a new term loan that is contingent upon the closing of the Acquisition. For further information regarding the Acquisition, please see "Risk Factors - The acquisition of PetroLatina may not be completed, and even if the acquisition is completed, we may fail to realize the benefits anticipated as a result of the acquisition."

Credit Facility

We have a credit facility with a syndicate of lenders. Availability under the credit facility is determined by a proven reserves-based borrowing base, and remains subject to the satisfaction of conditions precedent set forth in the credit agreement. Loans under the credit agreement are scheduled to mature on September 18, 2018. On June 2, 2016, we entered into a Second Amendment (the "Second Amendment") to our credit agreement dated September 18, 2015 (the "credit facility"). Pursuant to the Second Amendment, among other things, the committed borrowing base under our credit facility was reduced from \$200 million to \$185 million, with \$160 million readily available and \$25 million subject to the consent of all lenders. Further, the amount of permitted senior debt under the Company's credit facility was decreased from \$600 million to \$500 million.

The borrowing base will be re-determined semi-annually based on reserve evaluation reports, subject to a maximum of \$500 million. The next borrowing base redetermination is in late November 2016. The borrowing base for the credit facility is supported by the present value of the petroleum reserves of our subsidiaries with operating branches in Colombia. The credit agreement includes a letter of credit sub-limit of up to \$100 million. Amounts drawn down under the facility bear interest, at our option, at the USD LIBOR rate plus a margin ranging from 2.00% per annum to 3.00% per annum, or an alternate base rate plus a margin ranging from 1.00% per annum to 2.00% per annum, in each case based on the borrowing base utilization percentage. Undrawn amounts under the credit facility bear interest at 0.75% per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure.

Under the terms of the credit facility, we are required to maintain compliance with certain financial and operating covenants which include: the maintenance of a ratio of debt, including letters of credit, to net income plus interest, taxes, depreciation, depletion, amortization, exploration expenses and all non-cash charges minus all non-cash income ("EBITDAX") not to exceed 4.00 to 1.0; the maintenance of a ratio of senior secured obligations to EBITDAX not to exceed 3.00 to 1.00; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5 to 1.0. As at December 31, 2015, we were in compliance with all financial and operating covenants in our credit agreement. As of June 30, 2016, no amounts have been drawn on this facility. Under the terms of the credit facility, we are limited in our ability to pay any dividends to our shareholders without bank approval.

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

At June 30, 2016, 32% 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. As noted above, during the three months ended June 30, 2016, our parent company in the United States received net proceeds of \$108.9 million from the Notes offering and this significantly increased the percentage of cash and cash equivalents held by our subsidiaries and partnerships in Canada and the United States. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

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

Cash Flows

During the six months ended June 30, 2016, our cash and cash equivalents increased by \$26.1 million as a result of cash provided by operating activities of \$38.2 million and cash provided by financing activities of \$114.3 million, partially offset by cash used in investing activities of \$128.3 million (including \$50.9 million and \$19.4 million of cash used in investing activities in relation to the Petroamerica and PGC acquisitions, respectively).

Cash provided by operating activities in the six months ended June 30, 2016, was primarily affected by decreased oil and natural gas sales, higher transportation expenses and realized foreign exchange losses and a \$6.6 million change in assets and liabilities from operating activities. These amounts were partially offset by lower operating, G&A, severance, equity tax and income tax expenses and the absence of cash settlement of financial instruments.

Cash used in investing activities in the six months ended June 30, 2016, included an increase in restricted cash of \$2.3 million, capital expenditures incurred of \$44.6 million plus \$19.4 million of cash paid for property, plant and equipment for the PGC acquisition and net cash paid for the Petroamerica acquisition of \$50.9 million and \$11.1 million of net cash outflows related to changes in assets and liabilities associated with investing activities. Cash used in investing activities in the six months ended June 30, 2015, included an increase in restricted cash of \$0.3 million, capital expenditures incurred of \$91.3 million, and net cash outflows related to changes in assets and liabilities associated with investing activities of \$77.1 million.

Cash provided by financing activities in the six months ended June 30, 2016 relates to \$108.9 million of net proceeds on issuance of the Notes, net of issuance costs, and proceeds from issuance of shares of our Common Stock upon the exercise of stock options compared with solely proceeds from issuance of shares of our Common Stock upon the exercise of stock options in the corresponding period.

Off-Balance Sheet Arrangements

As at June 30, 2016, we had no off-balance sheet arrangements.

Contractual Obligations

During April 2016, we issued \$115.0 million aggregate principal amount of our Notes. The Notes bear interest at a rate of 5.00% per year, payable semi-annually in arrears on April 1 and October 1 of each year, beginning on October

1, 2016. The Notes will mature on April 1, 2021, unless earlier redeemed, repurchased or converted. See Note 6 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.

Except as noted above, as at June 30, 2016, there were no other material changes to our contractual obligations outside of the ordinary course of business from those as of December 31, 2015.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2015 Annual Report on Form 10-K, filed with the SEC on February 29, 2016, and have not changed materially since the filing of that document, other than as follows:

Derivative Activities

During the three months ended June 30, 2016, we entered into commodity price derivative contracts to manage the variability 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. We also entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs.

Under accounting rules, we may elect to designate certain derivative contracts that qualify for hedge accounting as hedges against the price that we will receive for our future oil and gas production. However, we do not designate any of our derivative contracts as accounting hedges. Because derivative contracts not designated for hedge accounting are accounted for on a mark-to-market basis, we are likely in the future to experience non-cash volatility in our reported net income or loss during periods of commodity price volatility.

As of June 30, 2016, we had derivative assets of \$7.0 million which are classified as a Level 2 fair value measurement. The value of these contracts at their respective settlement dates could be significantly different than the fair value as of June 30, 2016. 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. We also perform an internal valuation to ensure the reasonableness of third party quotes.

For further discussion of our derivative instruments and activities, see Note 12, "Financial Instruments, Fair Value Measurement, Credit Risk and Foreign Exchange Risk" to our condensed consolidated financial statements in Item 1 of this report for additional information regarding the accounting applicable to our derivative contracts, a listing of open contracts and the estimated fair market value of those contracts as of June 30, 2016.

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

In the six months ended June 30, 2016, we recorded ceiling test impairment losses in our Colombia and Brazil cost centers of \$132.8 million and \$15.4 million, respectively, related to lower oil prices. Holding all factors constant other than benchmark oil prices, it is reasonably likely that we will experience ceiling test impairment losses in our Brazil and Colombia cost centers in the third quarter of 2016.

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 believe that ceiling test impairment losses in the third quarter of 2016 could exceed \$5 million in Brazil and \$92 million in Colombia. The calculation of the impact of lower commodity prices on our estimated ceiling test calculation was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of benchmark oil prices. Therefore, this calculation strictly isolates the impact of commodity prices on the prescribed GAAP ceiling test. This calculation was based on pro forma Brent oil price of \$42.58 per bbl for the year ended September 30, 2016. These pro forma oil prices were calculated using a 12-month unweighted arithmetic average of oil prices, and included the oil prices on the first day of the month for the ten months ended July 30, 2016, and, for the two months ended September 30, 2016, estimated oil prices for the third quarter of 2016 using the forward price curve forecast of our independent reserves evaluator dated July 1, 2016. We used an average Brent price of \$44.48 per bbl for the purposes of the June 30, 2016, ceiling test calculations (March 31, 2016 - \$48.79; December 31, 2015 - \$54.08).

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

Holding all factors constant other than benchmark oil prices and related royalty rates, we do not expect any downward adjustment to our consolidated NAR reserve volumes during the third quarter of 2016. This disclosure is based on a pro forma Brent oil price of \$42.58 per bbl for the year ended September 30, 2016, calculated as described above.

Business Environment Outlook

Our revenues are significantly affected by the continuing fluctuations in world oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about the quantity of world supply and demand fundamentals, market competition between large producers, predominately members of OPEC (Organization of Petroleum Producing Countries), for

market share, political influences, financial markets and the impact of the worldwide economy on oil supply and demand growth.

We believe that our current operations and 2016 capital expenditure program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including additional pipeline delivery restrictions in Colombia or continued downturn in oil and gas prices, we would consider financing our capital expenditure program with borrowings under our revolving credit facility, proceeds from the disposition of assets or capital markets transactions, or a combination thereof, or we would consider reducing our capital expenditure program. We are the operator in the majority of our blocks and therefore have discretion on the timing of our capital expenditures. Given the current economic environment and unstable conditions in the Middle East, North Africa, and Europe and the current over supply of oil in world markets, the oil price environment is unpredictable and unstable. We are unable to determine the impact, if any, these events may have on oil prices and demand. The timing and execution of our capital expenditure program are also affected by the availability of services from third party oil field contractors and our ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities. Any delay may affect our ability to execute our capital expenditure program.

The credit markets, including the high yield bond market and other debt markets that provide capital to oil and gas companies have experienced adverse conditions. We have not been materially impacted by these conditions; however, continuing volatility in oil prices may continue to contribute to these adverse conditions, which could increase costs associated with renewing or issuing debt or affect our ability to access those markets.

Our future growth and acquisitions may depend on our ability to raise additional funds through equity and debt capital market transactions. Should we access such capital markets to fund capital expenditures or other acquisition and development opportunities, such funding may be affected by the market value of shares of our Common Stock. Issuing additional shares of Common Stock, or other equity securities convertible into Common Stock, may further dilute our existing shareholders. Any securities we issue may have rights, preferences and privileges that are senior to our existing equity securities. Borrowing money may also involve further pledging of some or all of our assets may require compliance with debt covenants and will expose us to interest rate risk. Depending on the currency used to borrow money, we may also be exposed to further foreign exchange risk. Our ability to borrow money and the interest rate we pay for any money we borrow will be affected by market conditions and we cannot predict what price we may pay for any borrowed money.

For over 40 years, the Colombian government has been engaged in a conflict with two main Marxist guerrilla groups: the Revolutionary Armed Forces of Colombia ("FARC") and the National Liberation Army ("ELN"). Both of these groups have been designated as terrorist organizations by the United States and the European Union. Another threat comes from criminal gangs formed from the former members of the United Self-Defense Forces of Colombia militia, a paramilitary group that originally sprouted up to combat FARC and ELN, which the Colombian government successfully dissolved. We operate principally in the Putumayo Basin in Colombia. Pipelines have been primary targets because such pipelines cannot be adequately secured due to the sheer length of such pipelines and the remoteness of the areas in which the pipelines are laid. The CENIT S.A.-operated Trans-Andean oil pipeline (the "OTA pipeline") which transports oil from the Putumayo region and which is one of our export routes, has been targeted by these guerrilla groups.

While peace talks continue between the Colombian government and the FARC, peace process negotiations between the government and FARC may not generate the intended outcome for both parties. The impact of such a peace process is not determinable on our operations. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain

the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

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.

During the three months ended June 30, 2016, we entered into commodity price derivative contracts to manage the variability 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 essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil. In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars or are based on U.S. dollar prices. In Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of our capital expenditures within Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. In Peru, capital expenditures are based on U.S. dollar prices and may be paid in local currency or U.S. dollars. The majority of income and value added taxes and G&A expenses in all locations are in local currency. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

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

During the three months ended June 30, 2016, we entered into foreign currency derivative contracts to manage the variability in cash flows associated with the Company's forecasted Colombian peso ("COP") denominated costs.

Further information

See Note 12 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 13a-15(e) of the Exchange Act. Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as of June 30, 2016.

Changes in Internal Control over Financial Reporting

We acquired Petroamerica Oil Corp. and PetroGranada Colombia Limited on January 13, 2016 and January 25, 2016, respectively, and are currently in the process of integrating these companies into our existing internal controls and procedures.

There were no changes in our internal control over financial reporting during the quarter ended June 30, 2016, 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 11 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, 2015, and material matters that have arisen since the filing of such report.

Item 1A. Risk Factors

See Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015. Except as set forth below, the risks facing our company have not changed materially from those set forth in Part I, Item 1A Risk Factors of our Annual Report on Form 10-K for the fiscal year ended December 31, 2015.

The acquisition of PetroLatina may not be completed, and even if the acquisition is completed, we may fail to realize the benefits anticipated as a result of the acquisition.

The Acquisition is expected to close prior to October 31, 2016, subject to customary closing conditions including, among other things, regulatory approval. If these conditions are not satisfied or waived, the Acquisition will not be consummated. There can be no assurances that the Acquisition will be consummated or that the expected benefits of the Acquisition will be realized. If the Acquisition is delayed, not consummated or consummated in a manner different than previously disclosed, the price of our common stock may decline.

Subsequent to the signing of the Acquisition Agreement, we paid \$5 million, which funds are to be held in escrow and applied to the initial payment at closing (the "Escrow Funds"). The Acquisition Agreement may be terminated by either Gran Tierra or the vendors under certain circumstances set forth in the Acquisition Agreement, including, among other circumstances, the failure of the Acquisition to be consummated on or before October 31, 2016. If the Acquisition Agreement is terminated by Gran Tierra as a result of the vendors breach of any representations, warranties, covenants or obligations, the Vendors' aggregate maximum liability will be limited to \$5.0 million, and the Escrow Funds will be returned to Gran Tierra. If the Acquisition Agreement is terminated as a result of Gran Tierra breaching any representations, warranties, covenants or obligations, Gran Tierra's maximum liability will be limited to the loss of the Escrow Funds deposited by Gran Tierra subsequent to the signing of the Acquisition Agreement. In addition, if the Acquisition Agreement is terminated in accordance with its terms or Gran Tierra announces that it does not intend to proceed with the Acquisition, the subscription for common stock represented by each private placement subscription receipt shall be automatically terminated and canceled and each holder shall receive an amount equal to \$3.00 per private placement subscription receipt held plus such holder's pro rata share of the Earned Interest (as defined in the Subscription Receipt Agreement), less applicable withholding taxes, all in the manner and on the terms and conditions set out in the Subscription Receipt Agreement.

If we are able to consummate the Acquisition, such consummation would involve potential risks, including, without limitation, inefficiencies and unexpected costs and liabilities. If we consummate the Acquisition and if these risks or other expected costs and liabilities were to materialize, any desired benefits of the Acquisition may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

Item 6. Exhibits

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

SIGNATURES

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

GRAN TIERRA ENERGY INC.

Date: August 5, 2016 /s/ Gary Guidry

By: Gary Guidry

President and Chief Executive Officer

(Principal Executive Officer)

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Date: August 5, 2016 /s/ Ryan Ellson
By: Ryan Ellson
Chief Financial Officer
(Principal Financial and Accounting Officer)

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1	Arrangement Agreement, dated November 12, 2015, between Gran Tierra Energy Inc. and Petroamerica Oil Corp.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 18, 2015 (SEC File No. 001-34018).
3.1	Amended and Restated Articles of Incorporation.	Incorporated by reference to Exhibit 3.1 to the Annual Report on Form 10-K, filed with the SEC on February 26, 2014 (SEC File No. 001-34018).
3.2	Amended and Restated Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed with the SEC on March 3, 2016 (SEC File No. 001-34018).
4.1	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).
4.2	Form of 5.00% Convertible Senior Notes due 2021.	Included as Exhibit A to Exhibit 4.1.
4.3	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).
4.4	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	Severance Agreement and Release dated April 6, 2016, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale.	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on May 3, 2016 (SEC File No. 001-34018).
10.2	Share Purchase Agreement dated as of June 30, 2016, among Gran Tierra Energy International Holdings Ltd., Tribeca Oil & Gas Inc., Macquarie Bank Limited, Rorick Ventures Group Inc., as vendors, and PetroLatina Energy Limited.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on July 7, 2016 (SEC File No. 001-34018).
10.3	Second Amendment to Credit Agreement, dated as of June 2, 2016, 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 June 3, 2016 (SEC File No. 34018).

- 10.4 Executive Employment Agreement effective June 24, 2016,
between Gran Tierra Energy Canada ULC, Gran Tierra Energy
Inc. and Ed Caldwell Filed herewith.
- 10.5 Executive Employment Agreement effective June 24, 2016,
between Gran Tierra Energy Canada ULC, Gran Tierra Energy
Inc. and Susan Mawdsley Filed herewith.
- 10.6 Executive Employment Agreement effective June 24, 2016,
between Gran Tierra Energy Canada ULC, Gran Tierra Energy
Inc. and Glen Mah Filed herewith.
- 10.7 Executive Employment Agreement effective June 24, 2016,
between Gran Tierra Energy Canada ULC, Gran Tierra Energy
Inc. and Rodger Trimble Filed herewith.
- 12.1 Statement re: Computation of Ratio of Earnings to Fixed Charges Filed herewith.

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| 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.