GRAN TIERRA ENERGY INC.
Form 10-Q
May 07, 2015

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

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

For the quarterly period ended March 31, 2015

or

o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from __________ to __________

Commission file number 001-34018

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

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 ý No o

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

Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

On May 1, 2015, the following number of shares of the registrant's capital stock were outstanding: 277,210,589 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 5,542,618 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

Three Months Ended March 31, 2015

Table of contents

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q, particularly in Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” 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, including without limitation statements in the Management’s Discussion and Analysis of Financial Condition and Results of Operations, 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 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. The information included herein is given as of the filing date of this 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	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
bopd	barrels of oil per day	MMBtu	million British thermal units
BOE	barrels of oil equivalent	NGL	natural gas liquids
MMBOE	million barrels of oil equivalent	NAR	net after royalty
BOEPD	barrels of oil equivalent per day		

Production represents production volumes NAR adjusted for inventory changes and losses. Our oil and gas reserves are also reported NAR.

NGL 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.

In the discussion that follows we discuss our interests in wells and/or acres in gross and net terms. Gross oil and natural gas wells or acres refer to the total number of wells or acres in which we own a working interest. Net oil and natural gas wells or acres are determined by multiplying gross wells or acres by the working interest that we own in such wells or acres. Working interest refers to the interest we own in a property, which entitles us to receive a specified percentage of the proceeds of the sale of oil and natural gas, and also requires us to bear a specified percentage of the cost to explore for, develop and produce that oil and natural gas. A working interest owner that owns a portion of the working interest may participate either as operator, or by voting its percentage interest to approve or disapprove the appointment of an operator, in drilling and other major activities in connection with the development of a property.

We also refer to royalties and farm-in or farm-out transactions. Royalties include payments to governments on the production of oil and gas, either in kind or in cash. Royalties also include overriding royalties paid to third parties. Our reserves, production volumes and sales are reported net after deduction of royalties. As noted above, production volumes are also reported net of inventory adjustments and losses. Farm-in or farm-out transactions refer to transactions in which a portion of a working interest is sold by an owner of an oil and gas property. The transaction is labeled a farm-in by the purchaser of the working interest and a farm-out by the seller of the working interest. Payment in a farm-in or farm-out transaction can be in cash or in kind by committing to perform and/or pay for certain work obligations.

In the petroleum industry, geologic settings with proven petroleum source rocks, migration pathways, reservoir rocks and traps are referred to as petroleum systems.

Several items that relate to oil and gas operations, including aeromagnetic and aerogravity surveys, seismic operations and several kinds of drilling and other well operations, are also discussed in this document.

Aeromagnetic and aerogravity surveys are a remote sensing process by which data is gathered about the subsurface of the earth. An airplane is equipped with extremely sensitive instruments that measure changes in the earth's gravitational and magnetic field. Variations as small as 1/1,000th in the gravitational and magnetic field strength and direction can indicate structural changes below the ground surface. These structural changes may influence the trapping of hydrocarbons. These surveys are an efficient way of gathering data over large regions.

Seismic data is used by oil and natural gas companies as the principal source of information to locate oil and natural gas deposits, both for exploration for new deposits and to manage or enhance production from known reservoirs. To gather seismic data, an energy source is used to send sound waves into the subsurface strata. These waves are reflected back to the surface by underground formations, where they are detected by geophones which digitize and record the reflected waves. Computer software applications are then used to process the raw data to develop an image of underground formations. 2-D seismic is the standard acquisition technique used to image geologic formations over a broad area. 2-D seismic data is collected by a single line of energy sources which reflect seismic waves to a single line of geophones. When processed, 2-D seismic data produces an image of a single vertical plane of sub-surface data. 3-D seismic data is collected using a grid of energy sources, which are generally spread over several square miles. A 3-D seismic survey produces a three dimensional image of the subsurface geology by collecting seismic data along parallel lines and creating a cube of information that can be divided into various planes, thus improving visualization. Consequently, 3-D seismic data is generally considered a more reliable indicator of potential oil and natural gas reservoirs in the area evaluated.

Wells drilled are classified as exploration, development, injector or stratigraphic. An exploration well is a well drilled in search of a previously undiscovered hydrocarbon-bearing reservoir. A development well is a well drilled to develop a hydrocarbon-bearing reservoir that is already discovered. Exploration and development wells are tested during and after the drilling process to determine if they have oil or natural gas that can be produced economically in commercial quantities. If they do, the well will be completed for production, which could involve a variety of equipment, the specifics of which depend on a number of technical geological and engineering considerations. If there is no oil or natural gas (a “dry” well), or there is oil and natural gas but the quantities are too small and/or too difficult to produce, the well will be abandoned. Abandonment is a completion operation that involves closing or “plugging” the well and remediating the drilling site. An injector well is a development well that will be used to inject fluid into a reservoir to increase production from other wells. A stratigraphic well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. These wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as “exploratory type” if drilled in an unknown area or “development type” if drilled in a known area.

Workover is a term used to describe remedial operations on a previously completed well to clean, repair and/or maintain the well for the purpose of increasing or restoring production. It could include well deepening, plugging portions of the well, working with cementing, scale removal, acidizing, fracture stimulation, changing tubulars or installing/changing equipment to provide artificial lift.

The SEC definitions related to oil and natural gas reserves, per Regulation S-X, reflecting our use of deterministic reserve estimation methods, are as follows:

- Reserves. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

- Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

i. The area of the reservoir considered as proved includes:

A. The area identified by drilling and limited by fluid contacts, if any; and

B. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

ii. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

iii. Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

iv. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

A. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

B. The project has been approved for development by all necessary parties and entities, including governmental entities.

v. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

i. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

ii. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

iii. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

iv. See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of section 210.4-10(a) of Regulations S-X.

- Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

5

i. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

ii. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

iii. Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

iv. The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

v. Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

vi. Pursuant to paragraph (a)(22)(iii) of section 210.4-10(a) of Regulations S-X, where direct observation has defined a HKO elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

- Reasonable certainty. If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and as changes due to increased availability of geoscience (geological, geophysical and geochemical), engineering and economic data are made to estimated ultimate recovery ("EUR") with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

- Deterministic estimate. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

- Probabilistic estimate. The method of estimating reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience, engineering or economic data) is used to generate a full range of possible outcomes and their associated probabilities of occurrences.

- Developed oil and gas reserves. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

i. Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well; and

ii. Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

- Undeveloped oil and gas reserves. Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

6

i. Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

ii. Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

iii. Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of section 201.4-10(a) of Regulation S-X, or by other evidence using reliable technology establishing reasonable certainty.

PART I - Financial Information

Item 1. Financial Statements

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

	Three Months Ended March 31,	
	2015	2014
REVENUE AND OTHER INCOME		
Oil and natural gas sales	$76,231	$151,105
Interest income	421	750
	76,652	151,855
EXPENSES		
Operating	31,434	21,866
Depletion, depreciation, accretion and impairment	86,154	44,264
General and administrative	7,294	12,863
Severance (Note 11)	4,378	—
Equity tax (Note 8)	3,769	—
Foreign exchange gain	(11,538)	(4,210)
Financial instruments gain (Note 10)	(42)	(2,409)
	121,449	72,374
(LOSS) INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	(44,797)	79,481
Income tax expense (Note 8)	(69)	(29,709)
(LOSS) INCOME FROM CONTINUING OPERATIONS	(44,866)	49,772
Loss from discontinued operations, net of income taxes (Note 3)	—	(4,643)
NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)	(44,866)	45,129
RETAINED EARNINGS, BEGINNING OF PERIOD	239,622	410,961
RETAINED EARNINGS, END OF PERIOD	$194,756	$456,090
(LOSS) INCOME PER SHARE		
BASIC		
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.16)	$0.18
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	—	(0.02)
NET INCOME (LOSS)	$(0.16)	$0.16
DILUTED		
(LOSS) INCOME FROM CONTINUING OPERATIONS	$(0.16)	$0.18
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	—	(0.02)
NET INCOME (LOSS)	$(0.16)	$0.16
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	286,194,315	283,235,202
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	286,194,315	288,636,904

(See notes to the condensed consolidated financial statements)

8

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

	March 31, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$203,460	$331,848
Restricted cash	707	1,836
Accounts receivable	64,825	83,227
Marketable securities (Note 10)	7,998	7,586
Inventory (Note 5)	16,095	17,298
Taxes receivable	8,258	15,843
Prepaids	5,472	6,000
Deferred tax assets (Note 8)	420	1,552
Total Current Assets	307,235	465,190
Oil and Gas Properties (using the full cost method of accounting)		
Proved	770,658	801,075
Unproved	334,613	316,856
Total Oil and Gas Properties	1,105,271	1,117,931
Other capital assets	10,890	11,013
Total Property, Plant and Equipment (Note 5)	1,116,161	1,128,944
Other Long-Term Assets		
Restricted cash	3,664	2,037
Deferred tax assets (Note 8)	568	601
Taxes receivable	15,035	9,684
Other long-term assets	4,394	5,013
Goodwill	102,581	102,581
Total Other Long-Term Assets	126,242	119,916
Total Assets	$1,549,638	$1,714,050
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable	$44,402	$112,401
Accrued liabilities	60,330	75,430
Foreign currency derivative (Note 10)	1,070	3,057
Taxes payable	8,844	25,412
Deferred tax liabilities (Note 8)	1,622	1,040
Asset retirement obligation (Note 7)	9,717	8,026
Total Current Liabilities	125,985	225,366
Long-Term Liabilities		
Deferred tax liabilities (Note 8)	158,932	175,324
Asset retirement obligation (Note 7)	25,458	27,786
Other long-term liabilities	7,364	8,889
Total Long-Term Liabilities	191,754	211,999

Contingencies (Note 9)		
Shareholders' Equity		
Common Stock (Note 6) (277,210,589 and 276,072,351 shares of Common Stock and 9,181,507 and 10,119,745 exchangeable shares, par value $0.001 per share, issued and outstanding as at March 31, 2015, and December 31, 2014, respectively)	10,190	10,190
Additional paid in capital	1,026,953	1,026,873
Retained earnings	194,756	239,622
Total Shareholders' Equity	1,231,899	1,276,685
Total Liabilities and Shareholders' Equity	$1,549,638	$1,714,050

(See notes to the condensed consolidated financial statements)

9

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

	Three Months Ended March 31,	
	2015	2014
Operating Activities		
Net income (loss)	$(44,866)	$45,129
Adjustments to reconcile net income (loss) to net cash (used in) provided by operating activities:		
Loss from discontinued operations, net of income taxes (Note 3)	—	4,643
Depletion, depreciation, accretion and impairment	86,154	44,264
Deferred tax recovery (Note 8)	(2,356)	(2,260)
Non-cash stock-based compensation	(513)	1,480
Unrealized foreign exchange gain	(9,037)	(4,178)
Unrealized financial instruments gain	(2,399)	(2,409)
Cash settlement of asset retirement obligation (Note 7)	(1,425)	—
Net change in assets and liabilities from operating activities of continuing operations		
Accounts receivable and other long-term assets	13,484	(53,396)
Inventory	2,159	(574)
Prepaids	528	551
Accounts payable and accrued and other long-term liabilities	(22,369)	(16,812)
Taxes receivable and payable	(19,983)	18,461
Net cash (used in) provided by operating activities of continuing operations	(623)	34,899
Net cash provided by operating activities of discontinued operations	—	1,265
Net cash (used in) provided by operating activities	(623)	36,164
Investing Activities		
(Increase) decrease in restricted cash	(497)	507
Additions to property, plant and equipment	(127,770)	(68,159)
Net cash used in investing activities of continuing operations	(128,267)	(67,652)
Net cash used in investing activities of discontinued operations	—	(6,987)
Net cash used in investing activities	(128,267)	(74,639)
Financing Activities		
Proceeds from issuance of shares of Common Stock (Note 6)	502	628
Net cash provided by financing activities	502	628
Net decrease in cash and cash equivalents	(128,388)	(37,847)
Cash and cash equivalents, beginning of period	331,848	428,800
Cash and cash equivalents, end of period	$203,460	$390,953
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	$55,335	$87,859

(See notes to the condensed consolidated financial statements)

10

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

	Three Months Ended March 31, 2015	Year Ended December 31, 2014
Share Capital		
Balance, beginning of period	$10,190	$10,187
Issue of shares of Common Stock (Note 6)	—	3
Balance, end of period	10,190	10,190
Additional Paid in Capital		
Balance, beginning of period	1,026,873	1,008,760
Exercise of stock options (Note 6)	502	11,137
Stock-based compensation (Note 6)	(422)	6,976
Balance, end of period	1,026,953	1,026,873
Retained Earnings		
Balance, beginning of period	239,622	410,961
Net loss	(44,866)	(171,339)
Balance, end of period	194,756	239,622
Total Shareholders' Equity	$1,231,899	$1,276,685

(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 oil and gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties. The Company’s principal business activities are in Colombia, Peru and Brazil. Until June 25, 2014, the Company also had business activities in Argentina.

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, 2014, included in the Company’s 2014 Annual Report on Form 10-K, filed with the Securities and Exchange Commission (“SEC”) on March 2, 2015.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2014 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

3. Discontinued Operations

On June 25, 2014, the Company, through several of its indirect subsidiaries (the “Selling Subsidiaries”), sold its Argentina business unit to Madalena Energy Inc. ("Madalena") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares.

The sale was made pursuant to agreements entered into by the Selling Subsidiaries (the “Agreements”); specifically, pursuant to the Agreements: (1) Madalena agreed to acquire from Gran Tierra Argentina Holdings ULC, an Alberta corporation (“GTE ULC”), and PCESA Petroleros Canadienses de Ecuador S.A., an Ecuador corporation (“PCESA”), both indirect subsidiaries of the Company, all of the outstanding shares of the Company’s indirect subsidiaries Gran Tierra Energy Argentina S.R.L. (“GTE Argentina”) and P.E.T.J.A. S.A, and agreed to acquire certain debt owed by GTE Argentina, for (a) approximately $44.8 million in cash, plus certain other adjustments and interest, and (b) shares of Madalena stock valued at $13.9 million; and (2) Madalena agreed to acquire from Gran Tierra Petroco Inc., an Alberta corporation (“Petroco”), an indirect subsidiary of the Company, all of the outstanding shares of the Company’s indirect subsidiary Petrolifera Petroleum Limited (“PPL”), and agreed to acquire certain debt owed by PPL , for approximately $10.6 million in cash, plus certain other adjustments and interest. Collectively, GTE Argentina, P.E.T.J.A. S.A., PPL and PPL’s subsidiaries held all of the assets of Gran Tierra's Argentina business unit.

Accordingly, the results of the Company’s Argentina business unit are classified as “Loss from discontinued operations, net of income taxes” on the consolidated statements of operations for the three months ended March 31, 2014.

Additionally, cash flows of the Company’s Argentina business unit are presented separately in the interim unaudited condensed consolidated statement of cash flows for the three months ended March 31, 2014, as cash provided by or used in operating and investing activities of discontinued operations. Amounts for 2014 have been reclassified to conform to the discontinued operations presentation. The reclassifications had no effect on net income (loss).

Revenue and other income and loss from discontinued operations, net of income taxes, for the three months ended March 31, 2014, were as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2014
Revenue and other income	$ 17,824
Loss from operations of discontinued operations before income taxes	$ (4,172)
Income tax expense	(471)
Loss from discontinued operations, net of income taxes	$ (4,643)

4. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company's reportable segments are Colombia, Peru and Brazil based on geographic organization. Prior to classifying the Company's Argentina business unit as discontinued operations, Argentina was a reportable segment. The All Other category represents the Company's corporate activities. The amounts disclosed in the tables below exclude the results of the Argentina business unit. Certain subsidiaries which were previously included in the All Other category were sold as part of the Argentina business unit, and therefore amounts disclosed in the All Other category have been reclassified to exclude amounts reported in loss from discontinued operations. The Company evaluates reportable segment performance based on income or loss from continuing operations before income taxes.

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

	Three Months Ended March 31, 2015				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 74,067	$ —	$ 2,164	$ —	$ 76,231
Interest income	67	—	140	214	421
Depletion, depreciation, accretion and impairment	46,255	32,948	6,594	357	86,154
Depletion, depreciation, accretion and impairment - per unit of production	27.41	—	112.50	—	49.35
Income (loss) from continuing operations before income taxes	2,928	(35,442)	(6,881)	(5,402)	(44,797)
Segment capital expenditures	21,367	38,034	13,901	719	74,021

	Three Months Ended March 31, 2014				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 144,935	$ —	$ 6,170	$ —	$ 151,105
Interest income	137	—	425	188	750
Depletion, depreciation, accretion and impairment	41,250	208	2,579	227	44,264
Depletion, depreciation, accretion and impairment - per unit of production	25.44	—	38.89	—	26.23
Income (loss) from continuing operations before income taxes	86,011	(2,058)	1,950	(6,422)	79,481
Segment capital expenditures	50,543	20,893	10,366	299	82,101

	As at March 31, 2015				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$863,087	$92,194	$155,880	$5,000	$1,116,161
Goodwill	102,581	—	—	—	102,581
All other assets	146,540	27,002	8,587	148,767	330,896
Total Assets	$1,112,208	$119,196	$164,467	$153,767	$1,549,638

	As at December 31, 2014				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Property, plant and equipment	$888,822	$87,028	$148,457	$4,637	$1,128,944
Goodwill	102,581	—	—	—	102,581
All other assets	157,549	40,613	14,724	269,639	482,525
Total Assets	$1,148,952	$127,641	$163,181	$274,276	$1,714,050

The Company’s revenues are derived principally from uncollateralized sales to customers in the oil and natural gas industry. The concentration of credit risk in a single industry affects the Company’s overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions.

In the three months ended March 31, 2015, the Company had one significant customer in Colombia: Ecopetrol S.A. ("Ecopetrol") which accounted for 79% of the Company's consolidated oil and natural gas sales from continuing operations. In the three months ended March 31, 2014, sales to Ecopetrol accounted for 48% of the Company's consolidated oil and natural gas sales from continuing operations and sales to one other significant customer accounted for 41% of the Company's consolidated oil and natural gas sales from continuing operations.

5. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

	As at March 31, 2015			As at December 31, 2014		
(Thousands of U.S. Dollars)	Cost	Accumulated depletion, depreciation and impairment	Net book value	Cost	Accumulated depletion, depreciation and impairment	Net book value
Oil and natural gas properties						
Proved	$1,898,962	$(1,128,304)	$770,658	$1,876,371	$(1,075,296)	$801,075
Unproved	334,613	—	334,613	316,856	—	316,856
	2,233,575	(1,128,304)	1,105,271	2,193,227	(1,075,296)	1,117,931
Furniture and fixtures and leasehold improvements	11,355	(8,236)	3,119	11,177	(8,421)	2,756
Computer equipment	15,246	(8,220)	7,026	14,323	(7,461)	6,862
Automobiles	1,569	(824)	745	1,787	(392)	1,395
Total Property, Plant and Equipment	$2,261,745	$(1,145,584)	$1,116,161	$2,220,514	$(1,091,570)	$1,128,944

On February 19, 2015, the Company made the decision to cease all further development expenditures on the Bretaña field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. As a result, in the year ended December 31, 2014, the Company recorded an impairment loss in the Company’s Peru cost center of

$265.1 million. This impairment charge related to costs incurred to December 31, 2014, on Block 95. In the three months ended March 31, 2015, the Company recorded an additional impairment loss in its Peru cost center of $32.7 million relating to costs incurred in the first quarter of 2015, on Block 95. Costs incurred in Peru on Block 95 in the three months ended March 31, 2015, comprised: $14.0 million of drilling costs for the Bretaña Sur 95-3-4-1X appraisal well; $6.2 million for the construction of the long-term test facilities, $5.0 million relating to contract termination fees associated with the decision not to proceed with the long-term test, and $7.5 million of other costs including restocking fees and the front end engineering design study. Total contract termination and restocking fees were $8.7 million.

Depletion and depreciation expense from continuing operations on property, plant and equipment for the three months ended March 31, 2015, was $49.8 million (three months ended March 31, 2014 - $44.3 million). A portion of depletion and depreciation expense was recorded as inventory in each period and adjusted for inventory changes.

In the three months ended March 31, 2015, we recorded a $4.3 million impairment loss in our Brazil cost center related to lower oil prices.

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Peru and Brazil. As at March 31, 2015, the Company had $173.0 million (December 31, 2014 - $170.5 million) of unproved assets in Colombia, $90.8 million (December 31, 2014 - $85.7 million) of unproved assets in Peru, and $70.8 million (December 31, 2014 - $60.7 million) of unproved assets in Brazil for a total of $334.6 million (December 31, 2014 - $316.9 million). Unproved oil and natural gas properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration warrants whether or not future areas will be developed.

Inventory

At March 31, 2015, oil and supplies inventories were $14.5 million and $1.6 million, respectively (December 31, 2014 - $15.2 million and $2.1 million, respectively).

6. Share Capital

The Company’s authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as Common Stock, par value $0.001 per share, 25 million are designated as Preferred Stock, par value $0.001 per share, and two shares are designated as special voting stock, par value $0.001 per share.

As at March 31, 2015, outstanding share capital consists of 277,210,589 shares of Common Stock of the Company, 5,542,618 exchangeable shares of Gran Tierra Exchangeco Inc., (the "Exchangeco exchangeable shares") and 3,638,889 exchangeable shares of Gran Tierra Goldstrike Inc. (the "Goldstrike exchangeable shares"). The redemption date for the Exchangeco exchangeable shares and the Goldstrike exchangeable shares is a date to be established by the applicable Board of Directors. During the three months ended March 31, 2015, 200,000 shares of Common Stock were issued upon the exercise of stock options, 52,500 shares of Common Stock were issued upon the exchange of the Exchangeco exchangeable shares and 885,738 shares of Common Stock were issued upon the exchange of the Goldstrike exchangeable shares.

The holders of shares of Common Stock are entitled to one vote for each share on all matters submitted to a stockholder vote and are entitled to share in all dividends that the Company’s Board of Directors, in its discretion, declares from legally available funds. The holders of Common Stock have no pre-emptive rights, no conversion rights, and there are no redemption provisions applicable to the shares. Holders of exchangeable shares have substantially the same rights as holders of shares of Common Stock. Each exchangeable share is exchangeable into one share of Common Stock of the Company.

Restricted Stock Units and Stock Options

The Company grants time-vested restricted stock units ("RSUs") to certain officers, employees and consultants. Additionally, the Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. The following table provides information about RSU and stock option activity for the three months ended March 31, 2015:

	RSUs Number of Outstanding Share Units	Options Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2014	1,236,963	13,790,220	5.93
Granted	826,450	2,193,260	2.75
Exercised	(377,254)	(200,000)	(2.51)
Forfeited	(412,893)	(986,308)	(6.82)
Expired	—	(380,665)	(6.05)
Balance, March 31, 2015	1,273,266	14,416,507	5.46

For the three months ended March 31, 2015, 200,000 shares of Common Stock were issued for cash proceeds of $0.5 million upon the exercise of stock options (three months ended March 31, 2014 - $0.6 million).

The weighted average grant date fair value for options granted in the three months ended March 31, 2015, was $1.10 (three months ended March 31, 2014 - $2.52).

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

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2015	2014
Compensation (recovery) costs for stock options	$ (422)	$ 2,016
Compensation (recovery) costs for RSUs	(60)	1,244
	(482)	3,260
Less: Stock-based compensation costs capitalized	(31)	(783)
Stock-based compensation costs (recovery) expense	$ (513)	$ 2,477

For the three months ended March 31, 2015, stock-based compensation was a recovery of $0.5 million due to the reversal of stock-based compensation expense for unvested options of terminated employees and a decrease in the Company's share price since December 31, 2014. The stock-based compensation recovery for the three months ended March 31, 2015, was primarily recorded in general and administrative ("G&A") expenses. Of the total stock-based compensation expense for the three months ended March 31, 2014, $2.1 million was recorded in G&A expenses, $0.1 million was recorded in operating expenses and $0.3 million was recorded in loss from discontinued operations.

At March 31, 2015, there was $6.1 million (December 31, 2014 - $4.8 million) of unrecognized compensation cost related to unvested stock options and RSUs which is expected to be recognized over a weighted average period of 1.7 years.

Income (loss) per share

Basic income (loss) per share is calculated by dividing income (loss) attributable to common shareholders by the weighted average number of shares of Common Stock and exchangeable shares issued and outstanding during each period. Diluted 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.

16

	Three Months Ended March 31,	
	2015	2014
Weighted average number of common and exchangeable shares outstanding	286,194,315	283,235,202
Weighted average shares issuable pursuant to stock options	—	14,553,754
Weighted average shares assumed to be purchased from proceeds of stock options	—	(9,152,052)
Weighted average number of diluted common and exchangeable shares outstanding	286,194,315	288,636,904

For the three months ended March 31, 2015, 13,742,502 options, on a weighted average basis, (three months ended March 31, 2014 - 3,175,152 options) were excluded from the diluted income per share calculation as the options were anti-dilutive.

7. Asset Retirement Obligation

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

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2015	Year Ended December 31, 2014
Balance, beginning of period	$35,812	$21,973
Settlements	(1,425)	(1,137)
Liability incurred	432	11,956
Liabilities associated with the Argentina business unit sold (Note 3)	—	(10,170)
Foreign exchange	—	(53)
Accretion	304	1,406
Revisions in estimated liability	52	11,837
Balance, end of period	$35,175	$35,812
Asset retirement obligation - current	$9,717	$8,026
Asset retirement obligation - long-term	25,458	27,786
Balance, end of period	$35,175	$35,812

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 March 31, 2015, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was $3.2 million (December 31, 2014 - $2.0 million). These assets are included in restricted cash on the Company's interim unaudited condensed consolidated balance sheets.

8. Taxes

The income tax expense reported differs from the amount computed by applying the U.S. statutory rate to income from continuing operations before income taxes for the following reasons:

	Three Months Ended March 31,	
(Thousands of U.S. Dollars)	2015	2014
(Loss) income from continuing operations before income taxes		
United States	$(2,068)	$(5,078)
Foreign	(42,729)	84,559
	(44,797)	79,481
	35%	35%
Income tax (recovery) expense from continuing operations expected	(15,679)	27,818
Foreign currency translation adjustments	(1,043)	(1,714)
Impact of foreign taxes	334	(921)
Other local taxes	1,597	842
Stock-based compensation	194	736
Increase in valuation allowance	12,674	3,190
Non-deductible third party royalty in Colombia	927	2,223
Other permanent differences	1,065	(2,465)
Total income tax expense from continuing operations	$69	$29,709
Current income tax expense from continuing operations		
United States	$225	$357
Foreign	2,200	31,612
	2,425	31,969
Deferred income tax recovery from continuing operations		
Foreign	(2,356)	(2,260)
Total income tax expense from continuing operations	$69	$29,709

	As at	
(Thousands of U.S. Dollars)	March 31, 2015	December 31, 2014
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	$49,447	$51,248
Tax basis in excess of book basis	121,340	108,120
Foreign tax credits and other accruals	19,179	20,369
Tax benefit of capital loss carryforwards	29,445	29,984
Deferred tax assets before valuation allowance	219,411	209,721
Valuation allowance	(218,423)	(207,568)
	$988	$2,153
Deferred tax assets - current	$420	$1,552
Deferred tax assets - long-term	568	601
	988	2,153
Deferred tax liabilities - current	(1,622)	(1,040)
Deferred tax liabilities - long-term	(158,932)	(175,324)
	(160,554)	(176,364)
Net Deferred Tax Liabilities	$(159,566)	$(174,211)

As at March 31, 2015, the Company had operating loss carryforwards of $163.9 million (December 31, 2014 - $167.0 million) and capital loss carryforwards of $230.6 million (December 31, 2014 – $232.2 million) before valuation allowance. Of these operating loss and capital loss carryforwards, $353.3 million (December 31, 2014 - $356.1 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between 2015 and

18

2035 and the capital loss carryforwards expire between 2016 and 2020, while certain other jurisdictions allow operating and capital losses to be carried forward indefinitely.

As at March 31, 2015, the total amount of Gran Tierra’s unrecognized tax benefit related to continuing operations was $3.2 million (December 31, 2014 - $3.3 million), which if recognized would affect the Company’s effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the interim unaudited condensed consolidated statement of operations.

Changes in the Company's unrecognized tax benefit relating to continuing operations are as follows:

	Three Months Ended March 31,	
	2015	2014
(Thousands of U.S. Dollars)		
Unrecognized tax benefit relating to continuing operations at beginning of period	$3,300	$2,900
Decreases for positions relating to prior year	(100)	(100)
Increases for positions relating to prior year	—	500
Unrecognized tax benefit relating to continuing operations at end of period	$3,200	$3,300

The Company and its subsidiaries file income tax returns in U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for the tax years 2007 through 2014 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

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 has recognized the annual amount of $3.8 million for the equity tax expense in the consolidated statement of operations during the three months ended March 31, 2015 and a corresponding payable on the consolidated balance sheet at March 31, 2015. At March 31, 2015, accounts payable included the unpaid balance of equity tax liability of $3.5 million (December 31, 2014 - $nil) which will be paid in May and September 2015.

As of March 31, 2015, the Company expects to make cash payments of $35.2 million for income and equity taxes in Colombia for the remainder of 2015. Of this amount, $15.8 million was paid in April 2015, $1.8 million is due in May 2015, $15.8 million is due in June 2015 and $1.8 million is due in September 2015.

9. Contingencies

Gran Tierra’s production from the Costayaco Exploitation Area is subject to an additional royalty (the "HPR royalty"), which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Block exploration and production contract (the "Chaza Contract") and the sales price. The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. Gran Tierra supplemented its claim on May 30, 2013. The ANH filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH's responses to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. As at March 31, 2015, total cumulative production from the Moqueta Exploitation Area was 4.8 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH's claims are accepted in the arbitration is $65.6 million plus related interest of $21.3 million. Gran Tierra also disagrees with the interest rate that the ANH has used in calculating the interest cost. Gran Tierra asserts that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum. At March 31, 2015, based on an interest rate of three-month LIBOR plus 4% related interest would be $4.2 million. At this time no amount has been accrued in the interim unaudited condensed consolidated financial statements nor deducted from the Company's reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. 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 $41.2 million as at March 31, 2015. 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.

Gran Tierra Energy Colombia, Ltd. and Petrolifera Petroleum (Colombia) Ltd (collectively “GTEC”) and Ecopetrol, the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long-term test of the Guayuyaco-1 and Guayuyaco-2 wells, prior to GTEC's purchase of the companies originally involved in the dispute. There was no agreement between the parties, and Ecopetrol filed a lawsuit in the Contravention Administrative Tribunal in the District of Cauca (the "Tribunal") regarding this matter. During 2013, the Tribunal ruled in favor of Ecopetrol and awarded Ecopetrol 44,025 bbl of oil. GTEC has filed an appeal of the ruling to the Supreme Administrative Court (Consejo de Estado) in a second instance procedure. At March 31, 2015, and December 31, 2014, Gran Tierra had accrued $2.4 million in the interim unaudited condensed consolidated financial statements in relation to this dispute.

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 March 31, 2015, the Company had provided promissory notes totaling $79.4 million (December 31, 2014 - $86.3 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

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

Financial Instruments

At March 31, 2015, the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, trading securities, accounts payable, accrued liabilities, foreign currency derivatives included in current assets and liabilities and contingent consideration included in other long-term liabilities.

Fair Value Measurement

The fair value of the trading securities, foreign currency derivatives and contingent consideration are being remeasured at the estimated fair value at the end of each reporting period.

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

The fair value of foreign currency derivatives was based on the estimated maturity value of foreign exchange non-deliverable forward contracts using applicable forward exchange rates. The most significant variable to the cash flow calculations is the estimation of forward foreign exchange rates. The resulting future cash inflows or outflows at maturity of the contracts are the net value of the contract.

The fair value of the contingent consideration, which relates to the acquisition of the remaining 30% working interest in certain properties in Brazil, was estimated based on the consideration expected to be transferred and discounted back to present value by applying an appropriate discount rate that reflected the risk factors associated with the payment streams. The discount rate used is determined in accordance with accepted valuation methods.

The fair value of the trading securities, foreign currency derivative liability and contingent consideration at March 31, 2015, and December 31, 2014, were as follows:

	As at	
(Thousands of U.S. Dollars)	March 31, 2015	December 31, 2014
Trading securities	$7,998	$7,586
Foreign currency derivative liability	$1,070	$3,057
Contingent consideration liability	1,061	1,061
	$2,131	$4,118

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 Ended March 31,	
	2015	2014
Trading securities gain	$(412)	$—
Foreign currency derivatives loss (gain)	370	(2,409)
	$(42)	$(2,409)

These gains are presented as financial instruments gain in the interim unaudited condensed consolidated statements of operations and cash flows. There were no sales of trading securities in the three months ended March 31, 2015, and the trading securities gain represents an unrealized gain.

The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

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

At March 31, 2015, and December 31, 2014, the fair value of the trading securities acquired in connection with the disposal of the Argentina business unit was determined using Level 1 inputs. At March 31, 2015, and December 31, 2014, the fair value of the foreign currency derivatives was determined using Level 2 inputs. At March 31, 2015, and December 31, 2014, the fair value of the contingent consideration payable in connection with the Brazil acquisition was determined using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of cash and restricted cash is 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.

Foreign Exchange Rate Risk

Unrealized foreign exchange gains and losses primarily result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra’s current and deferred tax liabilities, which are monetary liabilities mainly denominated in the local currency of the Colombian operations. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $62,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The Company purchases non-deliverable forward contracts for purposes of fixing exchange rates at which it will purchase or sell Colombian pesos to settle its income tax installment payments. With the exception of these foreign currency derivatives, any foreign currency transactions are conducted on a spot basis with major financial institutions in the Company’s operating areas.

At March 31, 2015, the Company had the following open foreign currency derivative positions:
Forward Contracts

Currency	Contract Type	Notional (Millions of Colombian Pesos)	Weighted Average Fixed Rate Received (Colombian Pesos - U.S. Dollars)	Expiration
Colombian pesos	Buy	12,468.2	2,116	April 2015

For the three months ended March 31, 2015, 97% (three months ended March 31, 2014 - 96%) of the Company's revenue and other income was generated in Colombia. In Colombia, the company receives 100% of its revenues in U.S. dollars and the majority of its 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 the Company's 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.

Credit Risk

Credit risk arises from the potential that the Company may incur a loss if a counterparty to a financial instrument fails to meet its obligation in accordance with agreed terms. The Company’s financial instruments that are exposed to concentrations of credit risk consist primarily of cash, accounts receivables and foreign currency derivatives. The carrying value of cash, accounts receivable and foreign currency derivatives reflects management’s assessment of credit risk.

At March 31, 2015, cash and cash equivalents and restricted cash included balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with financial institutions with strong investment grade ratings or governments, or the equivalent in the Company’s operating areas.

11. Severance Costs

In March 2015, largely as a result of the current low commodity price environment, the Company significantly reduced the number of its full-time employees. This was substantially completed at March 31, 2015. Employee termination benefits were recorded as incurred based on existing employee contracts, statutory requirements, completed negotiations and Company policy.

Severance costs for the Company’s reportable segments and other activities for the three months ended March 31, 2015, were as follows:

	Three Months Ended March 31, 2015				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Severance expenses	$1,166	$523	$109	$2,580	$4,378

The amounts in the above table also represent cumulative costs incurred to date.

At March 31, 2015, accounts payable and accrued liabilities included $2.5 million in relation to these actions which are expected to be settled within the six months ending September 30, 2015. Changes in the severance cost related liability were as follows:

(Thousands of U.S. Dollars)	Three Months Ended March 31, 2015
Balance, beginning of period	$—
Liability incurred	4,378
Settlements	(1,858)
Balance, end of period	$2,520

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

This report, and in particular this Management’s Discussion and Analysis of Financial Condition and Results of Operations, 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.

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 U.S. Securities and Exchange Commission (“SEC”) on March 2, 2015.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America in Colombia, Peru and Brazil, and we are headquartered in Calgary, Alberta, Canada.

During the three months ended March 31, 2015, largely as a result of the current low commodity price environment, we reevaluated our business strategy with a renewed focus on balancing the return and risk of our exploration and development projects. As a result, on February 19, 2015, we made the decision to cease all further development expenditures on the Bretaña field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. The high capital investment, associated debt financing and long-term payout horizon of this project does not align with our shift in strategy as announced on February 2, 2015.

As a result of this decision, all probable and possible reserves associated with the field were reclassified as contingent resources in a report with an effective date of January 31, 2015. Further, $265.1 million of unproved properties relating to Block 95 were impaired at December 31, 2014. An additional impairment loss of $32.7 million relating to the remaining drilling costs for the Bretaña Sur 95-3-4-1X appraisal well and other costs related to Block 95, which were incurred in the first quarter of 2015, was recognized in the three months ended March 31, 2015. These other costs included costs associated with construction of the long-term test facilities, contract termination and restocking fees and a front end engineering design ("FEED") study.

In March 2015, we announced cost reductions in line with our strategy to preserve our strong balance sheet and maximize potential for future growth. In addition to reductions in 2015 capital expenditures, we focused on reductions to our operating and general and administrative expenses, including lower service and transportation costs. In March 2015, we reduced the number of our full-time employees by 20% from previous staffing levels. Additionally, we are in ongoing negotiations with suppliers and service providers to achieve further savings.

On June 25, 2014, we sold our Argentina business unit to Madalena Energy Inc. ("Madalena") for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares. As such, the results of operations for our Argentina business unit are reflected as loss from discontinued operations, net of income taxes and discussed further in Note 3, "Discontinued Operations," of our interim unaudited condensed consolidated financial statements for the three months ended March 31, 2015.

For the three months ended March 31, 2015, 97% (three months ended March 31, 2014 - 96%) of our revenue and other income from continuing operations was generated in Colombia.

The price of oil is a critical factor to our business, has historically been volatile and has fallen dramatically in December 2014 through March 2015. Sustained periods of low oil prices have been detrimental to our financial performance. During three months ended March 31, 2015, the average price realized for our oil was $43.79 per barrel (three months ended March 31, 2014 - $89.89). Average Brent oil prices for the three months ended March 31, 2015, were $53.91 per bbl compared with $108.17 per bbl in the three months ended March 31, 2014. West Texas Intermediate ("WTI") oil prices for the three months ended March 31, 2015, were $48.63 per bbl compared with $98.68 per bbl in three months ended March 31, 2014.

Highlights

	Three Months Ended March 31,		
	2015	2014	% Change
Production (BOEPD) (1)(2)	19,399	18,753	3
Prices Realized - per BOE (1)	$43.66	$89.53	(51)
Revenue and Other Income ($000s) (1)	$76,652	$151,855	(50)
(Loss) Income from Continuing Operations ($000s) (1)	$(44,866)	$49,772	(190)
Loss from Discontinued Operations, Net of Income Taxes ($000s)	—	(4,643)	100
Net Income (Loss) ($000s)	$(44,866)	$45,129	(199)
(Loss) Income Per Share - Basic			
(Loss) Income from Continuing Operations (1)	$(0.16)	$0.18	(189)
Loss from Discontinued Operations, Net of Income Taxes	—	(0.02)	100
Net Income (Loss)	$(0.16)	$0.16	(200)
(Loss) Income Per Share - Diluted			
(Loss) Income from Continuing Operations (1)	$(0.16)	$0.18	(189)
Loss from Discontinued Operations, Net of Income Taxes	—	(0.02)	100
Net Income (Loss)	$(0.16)	$0.16	(200)
Funds Flow from Continuing Operations ($000s) (1)(3)	$25,558	$86,669	(71)
Capital Expenditures for Continuing Operations ($000s) (1)	$74,021	$82,101	(10)

	As at March 31, 2015	December 31, 2014	% Change
Cash & Cash Equivalents ($000s)	$203,460	$331,848	(39)
Working Capital (including Cash & Cash Equivalents) ($000s)	$181,250	$239,824	(24)
Property, Plant & Equipment ($000s)	$1,116,161	$1,128,944	(1)

(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes and losses, associated with discontinued operations was nil BOEPD for the three months ended March 31, 2015, and 3,066 BOEPD for the corresponding period in 2014.

(2) Production represents production volumes NAR adjusted for inventory changes and losses.

(3) Funds flow from continuing operations is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Management uses this financial measure to analyze operating performance and income or loss generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that this financial measure is also useful supplemental information for investors to analyze operating performance and our financial results. Investors are cautioned that this measure should not be construed as an alternative to net income or loss or other measures of financial performance as determined in accordance with

GAAP. Our method of calculating this measure may differ from other companies and, accordingly, it may not be comparable to similar measures used by other companies. Funds flow from continuing operations, as presented, is net income or loss adjusted for loss from discontinued operations, net of income taxes, depletion, depreciation, accretion and impairment (“DD&A”) expenses, deferred tax recovery, non-cash stock-based compensation, unrealized foreign exchange and financial instruments gains and cash settlement of asset retirement obligation. A reconciliation from net income or loss to funds flow from continuing operations is as follows:

	Three Months Ended March 31,	
Funds Flow From Continuing Operations - Non-GAAP Measure ($000s)	2015	2014
Net income (loss)	$(44,866)	$45,129
Adjustments to reconcile net income (loss) to funds flow from continuing operations		
Loss from discontinued operations, net of income taxes	—	4,643
DD&A expenses	86,154	44,264
Deferred tax recovery	(2,356)	(2,260)
Non-cash stock-based compensation	(513)	1,480
Unrealized foreign exchange gain	(9,037)	(4,178)
Unrealized financial instruments gain	(2,399)	(2,409)
Cash settlement of asset retirement obligation	(1,425)	—
Funds flow from continuing operations	$25,558	$86,669

- Oil and gas production, NAR before inventory adjustments and losses, was 20,140 BOEPD for the three months ended March 31, 2015, compared with 19,029 BOEPD in the corresponding period in 2014. In the three months ended March 31, 2015, production from new wells in the Moqueta field in the Chaza Block in Colombia had a positive effect on production. Production from the Costayaco field in the Chaza Block was consistent with the comparable period. Production in the three months ended March 31, 2015, was 86% from the Chaza Block in Colombia.

- Oil and gas production, NAR and adjusted for inventory changes and losses, increased by 3% to 19,399 BOEPD for the three months ended March 31, 2015, compared with 18,753 BOEPD in the corresponding period in 2014. During the three months ended March 31, 2015, an increase in oil inventory and losses ("oil inventory") accounted for 66,653 barrels or 741 bopd of reduced production compared with an oil inventory increase which accounted for 24,784 barrels or 276 bopd of reduced production in the corresponding period in 2014.

- For the three months ended March 31, 2015, revenue and other income decreased by 50% to $76.7 million compared with $151.9 million in the corresponding period in 2014. The decrease was primarily due to the effect of lower realized prices. The average price realized per BOE decreased by 51% to $43.66 for the three months ended March 31, 2015, from $89.53 in the comparable period in 2014.

- Loss from continuing operations for the three months ended March 31, 2015, was $44.9 million, or $0.16 per share basic and diluted, compared with income from continuing operations of $49.8 million, or $0.18 per share basic and diluted, in the corresponding period in 2014. In the three months ended March 31, 2015, we recorded impairment losses of $32.7 million in our Peru cost center relating to costs incurred on Block 95 and $4.3 million in our Brazil cost center due to lower oil prices. Additionally, loss from continuing operations was impacted by decreased oil and natural gas sales as a result of lower realized oil prices, higher operating, DD&A, severance and equity tax expenses and lower financial instrument gains which were partially offset by lower general and administrative ("G&A") expenses, increased foreign exchange gains and lower income tax expenses.

- Net loss was $44.9 million, or $0.16 per share basic and diluted, for the three months ended March 31, 2015, compared with net income of $45.1 million, or $0.16 per share basic and diluted, in the corresponding period in 2014. In the three months ended March 31, 2015, we recorded impairment losses of $32.7 million and $4.3 million in our Peru and Brazil cost centers, respectively.

- For the three months ended March 31, 2015, funds flow from continuing operations decreased by 71% to $25.6 million primarily due to decreased oil and natural gas sales as a result of lower oil realized prices, higher operating, severance and equity tax expenses, and higher realized financial instrument losses, partially offset by lower G&A expenses, higher realized foreign exchange gains and lower income tax expenses.

- Cash and cash equivalents were $203.5 million at March 31, 2015, compared with $331.8 million at December 31, 2014. The decrease in cash and cash equivalents for the three months ended March 31, 2015, was primarily the result of capital expenditures incurred during the quarter of $74.0 million ($21.4 million in Colombia, $38.0 million in Peru, $13.9 million in Brazil and $0.7 million Corporate), $53.8 million of net cash outflows related to changes in assets and liabilities associated with investing activities ($45.1 million outflow in Colombia, $9.4 million outflow in Peru, and a

$0.7 million inflow in Brazil and Corporate), a $26.1 million change in assets and liabilities from operating activities of continuing operations, a $0.5 million increase in restricted cash, partially offset by funds flow from continuing operations of $25.6 million, and proceeds from the issuance of shares of common stock of $0.5 million.

- Working capital (including cash and cash equivalents) was $181.3 million at March 31, 2015, a $58.6 million decrease from December 31, 2014. The decrease in working capital was primarily a result of a $128.3 million decrease in cash and cash equivalents, an $18.4 million decrease in accounts receivable primarily due to lower revenues, a $1.2 million decrease in inventory, a $1.7 million increase in the current portion of asset retirement obligation and a $1.7 million increase in net deferred tax liabilities, partially offset by a $83.1 million decrease in accounts payable and accrued liabilities due to lower drilling activity and lower accruals for royalties due to lower oil prices, a $2.0 million decrease in the foreign currency derivative and a $9.0 million decrease in net taxes payable primarily due to lower current income taxes for 2015 in Colombia.

- Property, plant and equipment at March 31, 2015, was $1.1 billion, a decrease of $12.8 million from December 31, 2014, as a result of $74.0 million of capital expenditures, which were more than offset by $86.8 million of depletion, depreciation and impairment expenses, including an impairment losses of $32.7 million and $4.3 million in our Peru and Brazil cost centers, respectively.

- Capital expenditures for continuing operations for the three months ended March 31, 2015, were $74.0 million compared with $82.1 million for the three months ended March 31, 2014. In 2015, these capital expenditures included drilling of $32.7 million, geological and geophysical (“G&G”) of $21.8 million, facilities of $16.9 million and other expenditures of $2.6 million.

Business Environment Outlook

Our revenues are significantly affected by the continuing fluctuations in oil prices and pipeline disruptions in Colombia. Oil prices are volatile and unpredictable and are influenced by concerns about the quantity of world supply and demand, market competition between large suppliers to the market 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 2015 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 another sharp downturn in oil and gas prices, we would examine measures such as further capital expenditure program reductions, use of our revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. Given the current economic environment, unstable conditions in the Middle East, North Africa and Eastern 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 markets. Should we be required to raise debt or equity financing 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. The current low and volatile oil price has had a negative impact on the value of shares of our Common Stock. Also, raising funds by issuing shares or other equity securities would further dilute our existing shareholders, and this dilution would be exacerbated by a decline in our share price. 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.

Consolidated Results of Operations

	Three Months Ended March 31,		
	2015	2014	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales (1)	$76,231	$151,105	(50)
Interest income (1)	421	750	(44)
	76,652	151,855	(50)
Operating expenses (1)	31,434	21,866	44
DD&A expenses (1)	86,154	44,264	95
G&A expenses (1)	7,294	12,863	(43)
Severance expenses (1)	4,378	—	—
Equity tax (1)	3,769	—	—
Foreign exchange gain (1)	(11,538)	(4,210)	(174)
Financial instruments gain (1)	(42)	(2,409)	98
	121,449	72,374	68
(Loss) income from continuing operations before income taxes (1)	(44,797)	79,481	(156)
Income tax expense (1)	(69)	(29,709)	(100)
(Loss) income from continuing operations (1)	(44,866)	49,772	(190)
Loss from discontinued operations, net of income taxes	—	(4,643)	100
Net income (loss)	$(44,866)	$45,129	(199)
Production (1)(2)			
Oil and NGL's, bbl	1,734,898	1,676,977	3
Natural gas, Mcf	66,026	64,779	2
Total production, BOE	1,745,902	1,687,774	3
Average Prices (1)			
Oil and NGL's per bbl	$43.79	$89.89	(51)
Natural gas per Mcf	$3.87	$5.48	(29)
Consolidated Results of Operations per BOE			
Oil and natural gas sales (1)	$43.66	$89.53	(51)
Interest income (1)	0.24	0.44	(45)
	43.90	89.97	(51)
Operating expenses (1)	18.00	12.96	39
DD&A expenses (1)	49.35	26.23	88
G&A expenses (1)	4.18	7.62	(45)
Severance expenses (1)	2.51	—	—
Equity tax (1)	2.16	—	—
Foreign exchange gain (1)	(6.61)	(2.49)	(165)
Financial instruments gain (1)	(0.02)	(1.43)	99
	69.57	42.89	62

(Loss) income from continuing operations before income taxes (1)	(25.67)	47.08	(155)
Income tax expense (1)	(0.04)	(17.60)	(100)
(Loss) income from continuing operations (1)	$(25.71)	$29.48	(187)

(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes and losses, associated with discontinued operations was nil BOEPD for the three months ended March 31, 2015, and 3,066 BOEPD for the three months ended March 31, 2014.

(2) Production represents production volumes NAR adjusted for inventory changes and losses.

Net loss for the three months ended March 31, 2015, was $44.9 million compared with net income of $45.1 million in the comparable period in 2014. On a per share basis, net loss was $0.16 per share basic and diluted for the three months ended March 31, 2015, compared with net income of $0.16 per share basic and diluted in the corresponding period in 2014. In the three months ended March 31, 2015, we recorded impairment losses of $32.7 million and $4.3 million in our Peru and Brazil cost centers, respectively.

Loss from continuing operations was $44.9 million, or $0.16 per share basic and diluted, for the three months ended March 31, 2015, compared with income from continuing operations of $49.8 million, or $0.18 per share basic and diluted, in the corresponding period in 2014. In the three months ended March 31, 2015, we recorded impairment losses of $32.7 million in our Peru cost center relating to costs incurred on Block 95 and $4.3 million in our Brazil cost center due to lower oil prices. Additionally, decreased oil and natural gas sales as a result of lower realized oil prices, higher operating, DD&A, severance and equity tax expenses and lower financial instrument gains were partially offset by lower G&A expenses, increased foreign exchange gains and lower income tax expenses.

Loss from discontinued operations, net of income taxes, was $nil for the three months ended March 31, 2015, compared with $4.6 million, or $0.02 per share basic and diluted, in the corresponding period in 2014. We sold our Argentina business unit on June 25, 2014.

Oil and NGL production, NAR before inventory adjustments and losses, for the three months ended March 31, 2015, increased to 20,017 bopd compared with 18,909 bopd in the corresponding period in 2014. In the three months ended March 31, 2015, production from new wells in the Moqueta field in the Chaza Block in Colombia had a positive effect on production. Production from the Costayaco field in the Chaza Block was consistent with the comparable period.

Oil and NGL production, NAR after inventory adjustments and losses, for the three months ended March 31, 2015, increased by 3% to 19,276 bopd compared with 18,633 bopd in the corresponding period in 2014. During the three months ended March 31, 2015, an oil inventory increase accounted for 0.1 MMbbl or 741 bopd of reduced production compared with an oil inventory increase which accounted for 24,784 barrels or 276 bopd of reduced production in the corresponding period in 2014.

Average realized oil prices decreased by 51% to $43.79 per bbl for the three months ended March 31, 2015, from $89.89 per bbl in the comparable period in 2014, primarily due to decreases in the benchmark prices. Average Brent oil prices for the three months ended March 31, 2015, were $53.91 per bbl, compared with $108.17 per bbl in the corresponding period in 2014. Average WTI oil prices for the three months ended March 31, 2015, were $48.63 per bbl compared with $98.68 per bbl in the corresponding period in 2014. Additionally, beginning July 1, 2014, the port operations fee component of the Trans-Andean oil pipeline ("OTA pipeline”) pricing structure increased by $2.94 per bbl resulting in a reduction of realized oil prices by this amount on sales delivered through the OTA pipeline.

During periods of OTA pipeline disruptions we use transportation alternatives. During the three months ended March 31, 2015, 20% of our oil volumes sold in Colombia, were through these transportation alternatives compared with 59% in the corresponding period in 2014. These sales have varying effects on our realized prices and transportation costs.

Revenue and other income for the three months ended March 31, 2015, decreased to $76.7 million from $151.9 million in the comparable period in 2014 primarily due to the effect of decreased realized oil prices.

Operating expenses increased by 44% to $31.4 million for the three months ended March 31, 2015, compared with the corresponding period in 2014. For the three months ended March 31, 2015, the increase in operating expenses was primarily due to an increase in the operating cost per BOE. On a per BOE basis, operating expenses increased by 39% to $18.00 for the three months ended March 31, 2015, from $12.96 in the comparable period in 2014. The increase in operating expenses per BOE in 2015 was primarily due to higher transportation costs of $2.59 per BOE associated with higher sales using the OTA pipeline which carried higher transportation costs instead of the realized price reductions that we incur with some alternative customers, and increased workover expenses of $2.70 per BOE.

DD&A expenses for the three months ended March 31, 2015, increased to $86.2 million from $44.3 million in the comparable period in 2014. As previously discussed, DD&A expenses in the three months ended March 31, 2015, included $32.7 million of impairment charges in our Peru cost center. Additionally, in the three months ended March 31, 2015, we recorded a $4.3 million ceiling test impairment loss in our Brazil cost center related to lower oil prices. On a per BOE basis, the depletion rate increased by 88% to $49.35 from $26.23 primarily due to the 2015 impairment charges.

G&A expenses for the three months ended March 31, 2015, decreased by 43% to $7.3 million ($4.18 per BOE) from $12.9 million ($7.62 per BOE) in the corresponding period in 2014. The decrease was mainly due to the effect of the strengthening of the U.S. dollar against the Colombian peso which resulted in significant savings for costs denominated in local currency and a 20% reduction in the number of our full-time employees in March 2015 as part of our cost saving measures and focus on reductions to our other G&A expenses. G&A expenses in the three months ended March 31, 2015, are net of a credit of $1.7 million ($0.97 per BOE) relating to the reversal of stock-based compensation expense for unvested options and restricted stock units ("RSUs") on employee terminations. G&A expenses per BOE in the three months ended March 31, 2015, of $4.18 were 45% lower compared with $7.62 in the corresponding period in 2014 for the same reasons.

Severance expenses for the three months ended March 31, 2015, were $4.4 million compared with $nil in the corresponding period in 2014. As noted above, in March 2015, we reduced the number of our full-time employees by 20%.

Equity tax expense for the three months ended March 31, 2015, of $3.8 million, represented a Colombian tax which was calculated based on our Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. The legal obligation for each year's equity tax liability arises on January 1 of each year, therefore, we recognized the 2015 annual amount of the equity tax payable on our interim unaudited condensed consolidated balance sheet at March 31, 2015, and a corresponding expense in our interim unaudited condensed consolidated statement of operations during the three months ended March 31, 2015.

For the three months ended March 31, 2015, the foreign exchange gain was $11.5 million, comprising a realized foreign exchange gain of $2.5 million and an unrealized non-cash foreign exchange gain of $9.0 million. For the three months ended March 31, 2014, there was a foreign exchange gain of $4.2 million, which was primarily a $4.2 million unrealized non-cash foreign exchange gain. Unrealized foreign exchange gains were primarily a result of a net monetary liability position in Colombia and the weakening of Colombian peso versus U.S. dollar.

In the three months ended March 31, 2015, financial instruments gains included $2.4 million of unrealized financial instruments gains which were offset by $2.4 million of realized financial instrument losses. In the three months ended March 31, 2015, we had a $0.4 million financial instrument loss on our Colombian peso non-deliverable forward contracts, comprising a $2.4 million realized loss and a $2.0 million unrealized gain. We purchased these contracts for purposes of fixing the exchange rate at which we will purchase or sell Colombian pesos to settle our income tax installments and payments. Financial instrument gains for the three months ended March 31, 2015, also included a $0.4 million unrealized gain on the Madalena shares we received in connection with the sale of our Argentina business unit. In the three months ended March 31, 2014, we had an unrealized gain of $2.4 million related to our Colombian peso non-deliverable forward contracts.

Income tax expense related to continuing operations was $0.1 million for the three months ended March 31, 2015, compared with $29.7 million in the comparable period in 2014. The decrease was primarily due to lower taxable income. The effective tax rate was 0.2% in the three months ended March 31, 2015, compared with 37% in the comparable period in 2014. The decrease in the effective tax rate was primarily due to losses before income taxes caused by the 2015 impairment losses and changes in stock-based compensation and the non-deductible third party royalty in Colombia, partially offset by changes in foreign currency translation adjustments, impact of foreign taxes, other local taxes, an increase in the valuation allowance, and other permanent differences.

For the three months ended March 31, 2015, the difference between the effective tax rate of 0.2% and the 35% U.S. statutory rate was primarily a result of a loss before income taxes caused by the 2015 impairment losses which was fully offset by an increase in the valuation allowance. Other factors that affected the effective tax rate in the three months ended March 31, 2015, were other local taxes, a non-deductible third party royalty in Colombia and other permanent differences, partially offset by foreign currency translation adjustments. The variance from the 35% U.S. statutory rate for the three months ended March 31, 2014, was primarily attributable to other local taxes, stock-based compensation, an increase in the valuation allowance and the non-deductible third party royalty in Colombia, partially offset by foreign currency translation adjustments, the impact of foreign taxes and other permanent differences.

2015 Capital Program

Our 2015 planned capital program has remained at $140 million. This includes $60 million for Colombia, $55 million for Peru, $24 million for Brazil and $1 million associated with corporate activities. The capital spending program allocates $45 million for drilling, $49 million for facilities, pipelines and other and $46 million for G&G expenditures. Approximately $35 million of the capital program is dedicated to the maintenance of existing production while $21 million is dedicated to drilling in Colombia.

The increase in the Peru capital program compared with the budget we released on February 9, 2015, is mainly due to increased costs to complete the seismic program on Block 107, increased drilling costs related to the Bretaña Sur 95-3-4-1X appraisal well, finalization of costs for decommissioning assets related to the long-term test facilities and other activities previously planned on the Bretaña field.

We expect to finance our 2015 capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds be expended as set forth in our 2015 capital program, there may be circumstances where, for business reasons, actual expenditures may in fact differ.

Segmented Results from Continuing Operations – Colombia

	Three Months Ended March 31,		
	2015	2014	% Change
(Thousands of U.S. Dollars)			
Oil and natural gas sales	$74,067	$144,935	(49)
Interest income	67	137	(51)
	74,134	145,072	(49)
Operating expenses	29,974	20,205	48
DD&A expenses	46,255	41,250	12
G&A expenses	2,716	4,383	(38)
Severance expenses	1,166	—	—
Equity tax	3,769	—	—
Foreign exchange gain	(13,043)	(4,368)	(199)
Financial instruments loss (gain)	369	(2,409)	115
	71,206	59,061	21
Income from continuing operations before income taxes	$2,928	$86,011	(97)
Production (1)			
Oil and NGL's, bbl	1,676,287	1,610,655	4
Natural gas, Mcf	66,026	64,779	2
Total production, BOE	1,687,291	1,621,452	4
Average Prices			
Oil and NGL's per bbl	$44.03	$89.73	(51)
Natural gas per Mcf	$3.87	$6.34	(39)
Segmented Results of Operations per BOE			
Oil and natural gas sales	$43.90	$89.39	(51)
Interest income	0.04	0.08	(50)
	43.94	89.47	(51)
Operating expenses	17.76	12.46	43
DD&A expenses	27.41	25.44	8
G&A expenses	1.61	2.70	(40)
Severance expenses	0.69	—	—
Equity tax	2.23	—	—
Foreign exchange gain	(7.73)	(2.69)	(187)
Financial instruments loss (gain)	0.22	(1.49)	115
	42.19	36.42	16
Income from continuing operations before income taxes	$1.75	$53.05	(97)

(1) Production represents production volumes NAR adjusted for inventory changes and losses.

32

For the three months ended March 31, 2015, income from continuing operations before income taxes was $2.9 million, compared with $86.0 million in the comparable period in 2014. For the three months ended March 31, 2015, the decrease was due to lower oil and natural gas sales primarily as a result of lower realized oil prices, increased operating, DD&A, severance and equity tax expenses and the absence of financial instrument gains, partially offset by lower G&A expenses and higher foreign exchange gains.

Oil and NGL production, NAR before inventory adjustments and losses, for the three months ended March 31, 2015, increased to 19,397 bopd compared with 18,152 bopd in the corresponding period in 2014. In the three months ended March 31, 2015, production from new wells in the Moqueta field in the Chaza Block and increased production on the Guayuyaco Block as a result of a successful well workover were partially offset by the impact of a water cut increase on the Juanambu field. Production from the Costayaco field in the Chaza Block was consistent with the comparable period. Production during the three months ended March 31, 2015, reflected approximately 10 days of oil delivery restrictions in Colombia compared with 51 days of oil delivery restrictions in the comparable period in 2014.

Oil and NGL production, NAR after inventory adjustments and losses, for the three months ended March 31, 2015, increased to 1.7 MMbbl or 18,625 bopd compared with 1.6 MMbbl or 17,896 bopd in the comparable period in 2014. During the three months ended March 31, 2015, an oil inventory increase accounted for decreased production of 0.1 MMbbl or 772 bopd compared with an oil inventory increase which accounted for 256 bopd reduced production in the comparable period in 2014.

Revenue and other income for the three months ended March 31, 2015, decreased by 49% to $74.1 million from the comparable period in 2014. For the three months ended March 31, 2015, the average realized price per bbl for oil decreased by 51% to $44.03 compared with $89.73 in the corresponding period in 2014. The decrease was primarily due to decreases in benchmark prices, as previously discussed. Additionally, an increase in the Port of Tumaco tariff effective July 1, 2014, reduced our Colombian realized oil price by approximately $2.36 per bbl in the three months ended March 31, 2015.

During periods of OTA pipeline disruptions, we conduct sales using transportation alternatives. These sales have varying effects on our realized prices and transportation costs. During the three months ended March 31, 2015, 20% of our oil volumes sold in Colombia were through these transportation alternatives. The effect on the Colombian realized price for the three months ended March 31, 2015, for sales using these transportation alternatives was an increase of approximately $0.01 per BOE, compared with delivering all of our Colombian oil through the OTA pipeline. Sales using these transportation alternatives during the corresponding period in 2014 were 59% of our oil and gas volumes sold in Colombia, and the effect on the Colombian realized price was a reduction of approximately $8.63 per BOE.

Operating expenses increased by 48% to $30.0 million for the three months ended March 31, 2015, compared with the comparable period in 2014 primarily due to increased operating costs per BOE. On a per BOE basis, operating expenses increased by 43% to $17.76 for the three months ended March 31, 2015, from $12.46 in the comparable period in 2014. The increase was primarily due to higher transportation costs associated with higher sales using the OTA pipeline which carried higher transportation costs instead of the realized price reductions that we incur with some alternative customers and higher workover expenses. The estimated net effect of OTA pipeline disruptions on Colombian transportation costs for the three months ended March 31, 2015, was an increase of $0.80 per BOE compared with a saving of $1.90 in the corresponding period in 2014. Additionally, in the three months ended March 31, 2015, workover expenses increased by $2.95 per BOE compared with the corresponding period in 2014. In 2015, workovers were performed on wells in the Moqueta and Costayaco fields.

DD&A expenses increased by 12% to $46.3 million for the three months ended March 31, 2015, from the comparable period in 2014 primarily as a result of increased DD&A expenses per BOE. On a per BOE basis, DD&A expenses in the three months ended March 31, 2015, increased by 8% to $27.41 due to increased costs in the depletable base and a reduction in proved reserves.

G&A expenses decreased by 38% to $2.7 million ($1.61 per BOE) from $4.4 million ($2.70 per BOE) for the three months ended March 31, 2015, from the comparable period in 2014. The decrease in G&A expenses was due to the effect of the strengthening of the U.S. dollar against the Colombian peso which resulted in significant savings for costs denominated in local currency, a significant reduction in the number of our full-time employees in March 2015 as part of our cost saving measures and focus on reductions to our other G&A expenses. This was partially offset by reduced G&A allocations to capital projects as a result of lower capital activity in the three months ended March 31, 2015.

Severance expenses for the three months ended March 31, 2015, were $1.2 million compared with $nil in the corresponding period in 2014. As noted above, in March 2015, we significantly reduced the number of our full-time employees.

Equity tax expense for the three months ended March 31, 2015, of $3.8 million, represented a Colombian tax which was calculated based on our Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015, as previously discussed.

For the three months ended March 31, 2015, the foreign exchange gain was $13.0 million, which included a $9.4 million unrealized non-cash foreign exchange gain. In the three months ended March 31, 2014, we had a foreign exchange gain of $4.4 million, which included a $4.2 million unrealized non-cash foreign exchange gain. The Colombian peso weakened by 8% and 2% against the U.S. dollar in the three months ended March 31, 2015, and 2014, respectively. Under 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 is the main source of the unrealized foreign exchange losses or gains.

Financial instruments loss of $0.4 million in the three months ended March 31, 2015, related to losses on our Colombian peso non-deliverable forward contracts and comprised a $2.4 million realized financial instruments loss and a $2.0 million unrealized gain. We purchased these contracts for purposes of fixing the exchange rate at which we purchase or sell Colombian pesos to settle our income tax installments and payments.

Capital Program - Colombia

Capital expenditures in our Colombian segment during the three months ended March 31, 2015, were $21.4 million. The following table provides a breakdown of capital expenditures in 2015 and 2014:

	Three Months Ended March 31,	
(Millions of U.S. Dollars)	2015	2014
Drilling and completions	$11.0	$30.6
G&G	6.0	11.1
Facilities and equipment	3.2	6.2
Other	1.2	2.6
	$21.4	$50.5

The significant elements of our first quarter 2015 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), we successfully completed, stimulated and tied-in the Moqueta-17 development well in the Moqueta field as an oil producer. We also drilled the Moqueta-18i development well and encountered mechanical difficulties. The well is currently suspended pending the results of injectivity testing at the Zapotero-1 well, which is interpreted to be in the same fault compartment as Moqueta 18i (the Moqueta South Block).

- We completed the acquisition of 2-D seismic on the Cauca-7 (100% WI, operated) and Sinu-3 (51% WI, operated) Blocks and continued activities in preparation for the acquisition of 2-D seismic on the Putumayo-10 Block (100% WI, operated). We also commenced environmental impact assessments ("EIA"s) for future drilling on the Sinu-3 Block.
- We continued facilities work at the Costayaco and Moqueta fields on the Chaza Block.

Outlook - Colombia

The 2015 capital program in Colombia is $60 million with $21 million allocated to drilling, $16 million to facilities and pipelines and $23 million for G&G expenditures.

Our planned capital program for the remainder of 2015 in Colombia includes drilling two gross development wells with our partner on the Garibay Block (50% WI, non-operated). Additionally, we plan to continue the interpretation and processing of 2-D seismic on the Cauca-7 and Sinu-3 Blocks and the acquisition of 2-D seismic on the Putumayo-10 Block. Facilities work is also planned for the Chaza and Garibay Blocks and we expect to pay back-in costs for the Putumayo-4 Block (70% operated, subject to ANH approval) farm-in.

Segmented Results from Continuing Operations – Peru

	Three Months Ended March 31,		
	2015	2014	% Change
(Thousands of U.S. Dollars)			
DD&A expenses	32,948	208	—
G&A expenses	1,040	1,642	(37)
Severance expenses	523	—	—
Foreign exchange loss	931	208	348
	35,442	2,058	—
Loss from continuing operations before income taxes	$(35,442)	$(2,058)	—

For the three months ended March 31, 2015, loss from continuing operations before income taxes in Peru was $35.4 million compared with $2.1 million in the comparable period in 2014. The increase in loss from continuing operations before income taxes was primarily due to an impairment loss in our Peru cost center of $32.7 million relating to costs incurred on Block 95. As previously discussed, in February 2015, we ceased all further development expenditures on the Bretaña field on Block 95 other than what is necessary to maintain tangible asset integrity and security and, as a result, costs incurred in relation to this project were impaired as at March 31, 2015.

DD&A expenses for the three months ended March 31, 2015, included $32.7 million of impairment charges as previously discussed.

G&A expenses were $1.0 million for the three months ended March 31, 2015, compared with $1.6 million in 2014. The decrease in G&A expenses was due to increased G&A allocations to capital projects, partially offset by higher salaries expenses in January and February 2015 due to expanded operations. In March 2015, we significantly reduced the number of our full-time employees as part of our cost saving measures and focus on reductions to our other G&A expenses, combined with increased G&A allocations to capital projects.

Severance expenses for the three months ended March 31, 2015, were $0.5 million compared with $nil in the corresponding period in 2014. As noted above, in March 2015, we significantly reduced the number of our full-time employees.

For the three months ended March 31, 2015, the foreign exchange loss was $0.9 million, compared with $0.2 million in 2014. The loss primarily relates to realized foreign exchange losses on monetary assets in Peru. The Peruvian Nuevo Sol weakened by 4% and 1% against the U.S. dollar in three months ended March 31, 2015, and 2014, respectively.

Capital Program – Peru

Capital expenditures in our Peruvian segment for the three months ended March 31, 2015, were $38.0 million, which included $32.7 million on Block 95 and $5.3 million on our other blocks in Peru. Our capital expenditures consisted of: drilling of $19.0 million, which included $14.0 million of drilling costs for the Bretaña Sur 95-3-4-1X appraisal well and $3.7 million of restocking fees associated with the cancellation of a multi-lateral trial well; facilities expenditures of $12.7 million, which included $6.2 million for the construction of the long-term test facilities, $5.0 million relating to contract termination fees associated with the decision not to proceed with the long-term test, and $1.5 million of costs related to the FEED study; G&G expenditures of $5.9 million; and asset retirement obligation and other expenditures of $0.4 million. Total contract termination and restocking fees were $8.7 million.

The significant elements of our first quarter 2015 capital program in Peru were:

- On Block 95 (100% WI, operated), we completed drilling operations on the Bretaña Sur 95-3-4-1X appraisal well on the L4 lobe on the Bretaña field, which satisfied our work obligation for the fifth exploration period. We encountered approximately six feet of oil pay above the oil-water contact in the Vivian Sandstone Reservoir. This oil column is less than what we had estimated prior to drilling. As previously discussed, in February 2015, we ceased all further development expenditures on the Bretaña field on Block 95 other than what is necessary to maintain tangible asset integrity and security. Prior to the decision to cease further development expenditures on the Bretaña field, we continued construction of the long-term test facilities, continued the FEED study for full field development and completed a workover on the water disposal well Bretaña Norte 95-2-1XD ST on this field.

- On Block 107 (100% WI, operated), we acquired 2-D seismic, commenced planning activities for the Osheki-1 exploration well and preparations for the refurbishment of the base camp and planned Osheki-1 well location. Both of these planning activities were suspended at the end of February 2015. Interpretation and processing of the 2-D seismic is ongoing.

Outlook - Peru

The 2015 capital program in Peru is $55 million with $19 million allocated to drilling primarily for the Bretaña Sur 95-3-4-1X appraisal well on the L4 lobe on the Bretaña field, $24 million for facilities and $12 million for G&G expenditures. The budgeted Bretaña Sur 95-3-4-1X appraisal well drilling costs were primarily incurred in January and February 2015.

Our planned capital program for the remainder of 2015 in Peru includes the dismantling, removal and abandonment of the long-term test facilities on Block 95. On Block 107, we plan to continue the permitting process for the Osheki-1 exploration well. On Blocks 123, 129 and 133, we plan to continue the permitting activity necessary to maintain the blocks and be ready for future activity.

Segmented Results from Continuing Operations – Brazil

	Three Months Ended March 31,		
	2015	2014	% Change
(Thousands of U.S. Dollars)			
Oil sales	$2,164	$6,170	(65)
Interest income	140	425	(67)
	2,304	6,595	(65)
Operating expenses	1,459	1,660	(12)
DD&A expenses	6,594	2,579	156
G&A expenses	627	651	(4)
Severance expenses	109	—	—
Foreign exchange loss (gain)	396	(245)	262
	9,185	4,645	98
(Loss) income from continuing operations before income taxes	$(6,881)	$1,950	(453)
Production (1)			
Oil and NGL's, bbl	58,611	66,322	(12)
Average Prices			
Oil and NGL's per bbl	$36.92	$93.03	(60)
Segmented Results of Operations per bbl			
Oil sales	$36.92	$93.03	(60)
Interest income	2.39	6.41	(63)
	39.31	99.44	(60)
Operating expenses	24.89	25.03	(1)
DD&A expenses	112.50	38.89	189
G&A expenses	10.70	9.82	9
Severance expenses	1.86	—	—
Foreign exchange loss (gain)	6.76	(3.69)	283
	156.71	70.05	124
(Loss) income from continuing operations before income taxes	$(117.40)	$29.39	(499)

(1) Production represents production volumes NAR adjusted for inventory changes and losses.

For the three months ended March 31, 2015, loss from continuing operations before income taxes was $6.9 million compared with income from continuing operations before income taxes of $2.0 million in the comparable period in 2014. In the three months ended March 31, 2015, we recorded a $4.3 million ceiling test impairment loss in our Brazil cost center. Loss from continuing operations before income taxes resulted from decreased oil and natural gas sales, increased DD&A expenses and foreign exchange losses.

Oil and NGL production in Brazil is from the Tiê field in Block 155 in the onshore Recôncavo Basin. Oil and NGL production for the three months ended March 31, 2015, was 0.1 Mbbl or 651 bopd compared with 0.1 Mbbl or 737 bopd in the comparable

37

---

period in 2014. Our operations on the Tiê Field have been suspended by the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") from March 11, 2015, due 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. We have provided documentation to the ANP to support compliance with certain regulations and await ANP approval to resume operations. Our production in Brazil continues to be limited due to gas flaring restrictions, but we are continuing to evaluate options to mitigate the effect of these restrictions.

Revenue and other income decreased to $2.3 million for the three months ended March 31, 2015, compared with $6.6 million in the comparable period in 2014. The decrease was due to decreased average realized prices combined with lower oil production levels. For the three months ended March 31, 2015, the average realized price per bbl for oil decreased by 60% to $36.92. The price we receive in Brazil is at a discount to Brent due to refining and quality discounts.

Operating expenses decreased to $1.5 million for the three months ended March 31, 2015, compared with $1.7 million in the comparable period in 2014 due to decreased production. On a per bbl basis, operating expenses of $24.89 for the three months ended March 31, 2015, were consistent with $25.03 per bbl in the corresponding period in 2014. Workover expenses were $nil per bbl in the three months ended March 31, 2015, compared with $4.19 per bbl in the comparable period in 2014, but this was offset by higher other operating costs per bbl due to reduced production.

DD&A expenses were $6.6 million ($112.50 per bbl) in the three months ended March 31, 2015, compared with $2.6 million ($38.89 per bbl) in the comparable period in 2014. In the three months ended March 31, 2015, we recorded a $4.3 million ceiling test impairment loss in our Brazil cost center related to lower oil prices. On a per bbl basis, the increase was due to the 2015 impairment charge combined with increased costs in the depletable base, partially offset by increased reserves.

G&A expenses were $0.6 million ($10.70 per bbl) in the three months ended March 31, 2015, consistent with $0.7 million ($9.82 per bbl) in the comparable period in 2014.

Severance expenses for the three months ended March 31, 2015, were $0.1 million compared with $nil in the corresponding period in 2014.

For the three months ended March 31, 2015, foreign exchange losses were $0.4 million compared with foreign exchange gains of $0.2 million in the three months ended March 31, 2014. The Brazilian Real weakened by 21% and strengthened by 3% against the U.S. dollar in the three months ended March 31, 2015 and 2014, respectively.

Capital Program – Brazil

Capital expenditures in our Brazilian segment during the three months ended March 31, 2015, were $13.9 million and consisted of drilling and other expenditures of $3.0 million, G&G expenditures of $9.9 million and facilities of $1.0 million.

Our first quarter 2015 capital program in Brazil included:

- On Blocks REC-T-86, Block REC-T-117 and Block REC-T-118 (100% WI, operated)), we completed the acquisition of 3-D seismic. Processing of the 3-D seismic is ongoing.

- On Block REC-T-155 (100% WI, operated), we initiated construction of an infield gas pipeline between the Tiê facilities and 3-GTE-03-BA.

Outlook – Brazil

The 2015 capital program in Brazil is $24 million with $5 million allocated to drilling, $8 million to facilities and pipelines and $11 million for G&G and other expenditures.

Our planned capital program for the remainder of 2015 in Brazil includes continued work on facilities, one workover in the Tiê field and seismic interpretation and processing on Block REC-T-86, Block REC-T-117 and Block REC-T-118. The First Appraisal Plan ("PAD") phase for Blocks REC-T-129, REC-T-142 and REC-T-155 will end May 24, 2015, before which must decide whether to move to the next exploration phase. We have requested a suspension of the PAD phase and are awaiting a response from the ANP.

Results from Continuing Operations - Corporate Activities

	Three Months Ended March 31,		
	2015	2014 (1)	% Change
(Thousands of U.S. Dollars)			
Interest income	$214	$188	14
DD&A expenses	357	227	57
G&A expenses	2,911	6,188	(53)
Severance expenses	2,580	—	—
Foreign exchange loss	180	195	(8)
Financial instruments gain	(412)	—	—
	5,616	6,610	(15)
Loss from continuing operations before income taxes	$(5,402)	$(6,422)	16

(1) Certain entities which were previously reported in Corporate Activities were sold as part of the Argentina business unit, and amounts previously reported in Corporate Activities related to these entities have been reclassified to loss from discontinued operations.

G&A expenses in the three months ended March 31, 2015, were $2.9 million compared with $6.2 million in the comparable period in 2014. In March 2015, we significantly reduced the number of our full-time employees as part of our cost saving measures and focus on reductions to our other G&A expenses. G&A expenses in the three months ended March 31, 2015, are net of a credit of $1.7 million relating to the reversal of stock-based compensation expense for unvested options and RSUs associated with terminated employees.

Severance expenses for the three months ended March 31, 2015, were $2.6 million compared with $nil in the corresponding period in 2014. As noted above, in March 2015 we significantly reduced the number of our full-time employees.

Financial instruments gain was $0.4 million in the three months ended March 31, 2015, and consisted solely of unrealized financial instruments gains on the Madalena shares we received in connection with the sale of our Argentina business unit. Madalena is an independent, Canadian-based, domestic and international upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Madalena's shares are listed on the Canadian TSX Venture Exchange.

Results from Discontinued Operations

On June 25, 2014, we sold our Argentina business unit to Madalena for aggregate consideration of $69.3 million, comprising $55.4 million in cash and $13.9 million in Madalena shares. Loss from discontinued operations, net of income taxes was $nil for the three months ended March 31, 2015, compared with $4.6 million in the corresponding period in 2014.

Liquidity and Capital Resources

At March 31, 2015, we had cash and cash equivalents of $203.5 million compared with $331.8 million at December 31, 2014.

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 2015, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc., 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.

At March 31, 2015, 82% of our cash and cash equivalents were held by subsidiaries and partnerships outside of Canada and the United States. This cash was generally not available to fund domestic or head office operations unless funds were repatriated.

At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The government in Brazil requires us to register funds that enter and exit the country with the central bank. In Brazil and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in the Special Exchange Regime, which allows us to 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.

At March 31, 2015, one of our subsidiaries had a credit facility with a syndicate of banks, led by Wells Fargo Bank National Association as administrative agent. This reserve-based facility has a current borrowing base of $150 million and a maximum borrowing base that is dependent on the value of our reserves as assessed by the banking syndicate, but in no case would be more than $300 million. The borrowing base for the credit facility is supported by the present value of the petroleum reserves of two of our subsidiaries with operating branches in Colombia and our subsidiary in Brazil. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus a margin ranging between 2.25% and 3.25% per annum depending on the rate of borrowing base utilization. In addition, a stand-by fee of 0.875% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. The credit facility was entered into on August 30, 2013, and became effective on October 31, 2013, for a three-year term. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. Under the terms of the credit facility, we cannot pay any dividends to our shareholders if we are in default under the facility and, if we are not in default, we are required to obtain bank approval for any dividend payments exceeding $2.0 million in any fiscal year. No amounts have been drawn on this facility.

Cash Flows

During the three months ended March 31, 2015, our cash and cash equivalents decreased by $128.4 million as a result of cash used in operating activities of $0.6 million and cash used in investing activities of $128.3 million, partially offset by cash provided by financing activities of $0.5 million. During the three months ended March 31, 2014, our cash and cash equivalents decreased by $37.8 million as a result of cash used in investing activities of $74.6 million (included $7.0 million of cash used for investing activities of discontinued operations), partially offset by cash provided by operating activities of $36.2 million (included $1.3 million of cash provided by operating activities of discontinued operations) and cash provided by financing activities of $0.6 million.

Cash used in operating activities in the three months ended March 31, 2015, was primarily affected by decreased oil and natural gas sales as a result of lower oil realized prices, higher operating, severance and equity tax expenses, higher realized financial instrument losses, and a $26.1 million change in assets and liabilities from operating activities. These amounts were partially offset by lower G&A expenses, higher realized foreign exchange gains, and lower income tax expenses.

The main changes in assets and liabilities from operating activities were as follows: accounts receivable decreased by $13.5 million primarily due to lower revenues; inventory decreased by $2.2 million primarily due to lower inventory costs, partially offset by higher inventory volumes; accounts payable and accrued liabilities decreased by $22.4 million due to a reduction in drilling activity and lower accruals for royalties due to lower oil prices; and net taxes receivable increased by $20.0 million primarily due to lower current income taxes for 2015 in Colombia.

Cash provided by operating activities of continuing operations in the three months ended March 31, 2014, included funds flow from continuing operations of $86.7 million and cash provided by operating activities of discontinued operations of $1.3 million, partially offset by a $51.8 million change in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets increased by $53.4 million primarily due to an increase in the number of days of sales outstanding in Colombia as a result of a higher portion of sales being to Ecopetrol S.A. which has longer payment terms than our other significant customer; inventory increased by $0.6 million; accounts payable and accrued liabilities decreased by $16.8 million due to the timing of payments for drilling activity; and net taxes payable increased by $18.5 million due to increased taxable income in Colombia.

Cash used in investing activities of continuing operations in the three months ended March 31, 2015, included capital expenditures incurred during the three months ended March 31, 2015, of $74.0 million ($21.4 million in Colombia, $38.0 million in Peru, and $13.9 million in Brazil and $0.7 million Corporate), $53.8 million of net cash outflows related to changes in assets and liabilities associated with investing activities ($45.1 million outflow in Colombia, $9.4 million outflow in Peru, and a $0.7 million inflow in Brazil and Corporate),and an increase in restricted cash of $0.5 million. Cash used in investing activities of continuing operations in the three months ended March 31, 2014, included cash capital expenditures of $68.2 million, partially offset by a decrease in restricted cash of $0.5 million.

Cash provided by financing activities of continuing operations in the three months ended March 31, 2015 and 2014, related to proceeds from issuance of shares of our Common Stock upon the exercise of stock options.

West Face Capital, Inc., or West Face, has initiated a proxy contest with respect to the matters to be voted upon at our 2015 annual meeting of stockholders, or the Annual Meeting. Among other things, West Face is proposing to solicit proxies in opposition to us for the purpose of voting in favor of its six nominees for election to our board of directors. West Face communicated to us, and states explicitly, that the board of directors should replace our chief executive officer. Responding to the potential proxy contest is costly and time-consuming, is a significant distraction for our board of directors, management and employees, and diverts the attention of our board of directors and senior management from the pursuit of our business strategy, which could adversely affect our results of operations and financial condition. Further, we have incurred, and will continue to incur, expenses for legal and advisory fees and administrative and associated costs incurred in connection with responding to the potential proxy contest, which may include related litigation, which costs may be substantial.

Off-Balance Sheet Arrangements

As at March 31, 2015, we had no off-balance sheet arrangements.

Contractual Obligations

As at March 31, 2015, there were no material changes to our contractual obligations outside of the ordinary course of business from those as of December 31, 2014.

Critical Accounting Policies and Estimates

Our critical accounting policies and estimates are disclosed in Item 7 of our 2014 Annual Report on Form 10-K, filed with the SEC on March 2, 2015, and have not changed materially since the filing of that document. If Brent oil prices continue at current levels, we continue to believe that it is reasonably likely that we would record further ceiling test impairment losses in our Brazil cost center and possibly a ceiling test impairment loss in our Colombia cost center in 2015. Additionally, we expect to record further impairment losses in our Peru cost center for costs incurred on Block 95 in 2015.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Our principal market risk relates to oil prices. Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand and many other market factors outside of our control. Oil prices started falling in September 2014 and have fallen dramatically during the period December 2014 to March 2015. 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.

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. We have engaged in non-deliverable foreign exchange contracts to buy or sell Colombian pesos in order to fix the exchange rate of our income tax installments and payments in

Colombia. At March 31, 2015, we held Colombia peso non-deliverable forward contracts totaling 12.5 billion Colombian pesos.

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. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $62,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The table below provides information about our foreign currency forward exchange agreements at March 31, 2015, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equal the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. The increase or decrease in the value of the forward contract is offset by the increase or decrease to the U.S. dollar equivalent of the Colombian peso current tax liabilities. We do not hold any of these investments for trading purposes.

	As at March 31, 2015				
Currency	Contract Type	Notional (Millions of Colombian Pesos)	Weighted Average Fixed Rate Received (Colombian Pesos - U.S. Dollars)	Fair Value of the Forward Contracts (thousands of U.S. Dollars)	Expiration
Colombian pesos	Buy	12,468.2	2,116	(1,070)	April 2015

This compares to our foreign currency forward exchange agreements at December 31, 2014, as follows:

	As at December 31, 2014				
Currency	Contract Type	Notional (Millions of Colombian Pesos)	Weighted Average Fixed Rate Received (Colombian Pesos - U.S. Dollars)	Fair Value of the Forward Contracts (thousands of U.S. Dollars)	Expiration
Colombian pesos	Buy	51,597.5	2,006	(4,175)	February and April 2015
Colombian pesos	Sell	10,275.3	1,895	1,118	February 2015

Interest Rate Risk

We consider our exposure to interest rate risk to be immaterial. Our interest rate exposures primarily relate to our investment portfolio. Our investment objectives are focused on preservation of principal and liquidity. By policy, we manage our exposure to market risks by limiting investments to high quality bank issues at overnight rates, or U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. A 10% change in interest rates would not have a material effect on the value of our investment portfolio. We do not hold any of these investments for trading purposes. We have no debt.

Equity Investment in Madalena Energy Inc.

We hold an equity investment in Madalena Energy Inc. ("Madalena"), received as consideration in the sale of our Argentina business unit, which closed June 25, 2014. We hold 29,831,537 shares of Madalena which had a value of $7.6 million at December 31, 2014, and $8.0 million at March 31, 2015, and represented approximately 5.7% of

Madalena's outstanding shares at March 31, 2015. These shares trade on the TSX Venture Exchange and as such are subject to changes in value that are outside of our control. We may face market related obstacles such as trading volume and value in divesting these shares.

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 management, including our Executive Chairman of the Board, Interim Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of March 31, 2015, 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 Executive Chairman of the Board, Interim Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended March 31, 2015, 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

As discussed in Note 9 of Notes to Condensed Consolidated Financial Statements (Unaudited) in Part I, Item 1 above, Gran Tierra’s production from the Costayaco Exploitation Area is subject to the HPR royalty, which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. Gran Tierra supplemented its claim on May 30, 2013. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH defense to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. As at March 31, 2015, total cumulative production from the Moqueta Exploitation Area was 4.8 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH's claims are accepted in the arbitration is $65.6 million plus related interest of $21.3 million. Gran Tierra also disagrees with the interest rate that the ANH has used in calculating the interest cost. Gran Tierra asserts that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum. At March 31, 2015, based on an interest rate of three-month LIBOR plus 4% related interest would be $4.2 million. At this time, no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $41.2 million as at March 31, 2015. At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

We have several other lawsuits and claims pending. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we believe the resolution of these matters would not have a material adverse effect on our consolidated financial position, results of operations or cash flows. We record costs as they are incurred or become probable and determinable.

Item 1A. Risk Factors

The risks relating to our business and industry, as set forth in our Annual Report on Form 10-K for the year ended December 31, 2014, filed with the Securities and Exchange Commission on March 2, 2015, are set forth below and are unchanged substantively, other than as designated by an asterisk *.

Risks Related to Our Business

Guerrilla Activity in Colombia Has Disrupted and Delayed, and Could Continue to Disrupt or Delay, Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Colombia.

During 2012 and 2013, guerrilla activity in Colombia increased significantly, and the activity level remained high in 2014 and into 2015 to date. This increased activity creates a greater risk for our operations and our employees and our mitigation activities may not be adequate to alleviate the risks arising from such guerrilla activity.

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, and have properties in other basins, including the Catatumbo, Cauca, Llanos, Sinu-San Jacinto, Middle Magdalena and Lower Magdalena Basins. The Putumayo and Catatumbo regions have been the breeding place of guerrilla activity. 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 Ecopetrol-operated Trans-Andean oil pipeline (the "OTA pipeline") which transports oil from the Putumayo region and upon which we materially rely has been targeted by these guerrilla groups. Starting in 2008, the OTA pipeline experienced outages of various lengths. In 2012, the OTA pipeline was shutdown for over 162 days and the shutdown had a material adverse effect on our deliveries to Ecopetrol and our financial performance for 2012. Recently we have experienced outages from October 2012 through to April 2015. In 2014, the OTA pipeline was shutdown for approximately 180 days, which included 49 days as a result of a landslide. In the three months ended March 31, 2015, the OTA pipeline was shutdown for approximately 10 days. We have employed mitigation strategies as discussed in the risk "We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses" later in this section. Such disruptions may continue indefinitely and could harm our business.

In 2013, we experienced damage to two of our facilities in the amount of approximately $0.8 million. Production of about 330 bopd was shut in for 39 days. No long-term environmental damage or injury to personnel occurred in either incident. 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.

Our Lack of Diversification Will Increase the Risk of an Investment in Our Common Stock.

Our business focuses on the oil and gas industry in a limited number of properties in Colombia, Peru, and Brazil. Most of our production is in one basin in Colombia. As a result, we lack diversification, in terms of both the nature and geographic scope of our business. Accordingly, factors affecting our industry, such as the price of oil, or the regions in which we operate, including the geographic remoteness of our operations and weather conditions, will likely impact us more acutely than if our business was more diversified. In particular, most of our production is from two fields in the Putumayo Basin in Colombia, and we depend on the OTA pipeline and alternative transportation arrangements to transport our oil to market. Cash flow from these sales funds a large part of our business. Disruptions to this pipeline, as described in the risk "We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses", or decline in production from these fields because of the natural aging cycle of the reservoir could harm our business in Colombia and other countries.

We Have an Aggressive Business Plan, and if We do Not Have the Resources to Execute on Our Business Plan, We May Be Required to Curtail Our Operations.

Our revised preliminary capital program for 2015 calls for approximately $140 million to fund our exploration and development, which we intend to fund through cash flows from operations and cash on hand. Funding this program relies in part on oil prices remaining close to current levels or higher and other factors to generate sufficient cash flow. Oil prices were very volatile at the end of 2014 and have remained at low levels in the first part of 2015. We have restricted activity and lowered our planned capital spending for 2015. Low oil prices affect our debt capacity and the amount of money we can borrow using our oil reserves as collateral, as well as the amount of cash we are able to generate from current operations. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our business plan which would cause us to further decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses.

To sell the oil and natural gas that we are able to produce, we have to make arrangements for storage and distribution to the market. We rely on local infrastructure and the availability of transportation for storage and shipment of our products, but infrastructure development and storage and transportation facilities may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. This could be particularly problematic to the extent that our operations are conducted in remote areas that are difficult to access, such as areas that are distant from shipping and/or pipeline facilities. In certain areas, we may be required to rely on only one gathering system, trucking company or pipeline, and, if so, our ability to market our production would be subject to their reliability and operations. These factors may affect our ability to explore and develop properties and to store and transport our oil and gas production, and may increase our expenses. Furthermore, future instability in one or more of the countries in which we operate, weather conditions or natural disasters, actions by companies doing business in those countries, labor disputes or actions taken by the international community may impair the distribution of oil and/or natural gas and in turn diminish our financial condition or ability to maintain our operations.

The majority of our oil in Colombia is contracted for delivery to a single pipeline owned by CENIT S.A. ("CENIT"), a wholly-owned subsidiary of Ecopetrol, and operated by Ecopetrol. Sales of oil have been and could continue to be disrupted by damage to this pipeline or displaced by Ecopetrol’s use of the pipeline itself. In addition, CENIT has a monopoly over pipeline transportation from the area as well as operation of the port of Tumaco, which limits our ability to negotiate on pipeline and port tariff increases and our costs may increase as a result. Under our transportation contract with CENIT, the delivery point for our oil is at the end of the pipeline. This creates a risk of loss of oil due to sabotage by guerrillas or theft from the pipeline which may result in reduced revenues and increased clean-up or third party costs. We have attempted to mitigate the risk of increased costs with insurance and are investigating potential ways to mitigate and reduce revenue risk. CENIT and Ecopetrol maintain responsibility for clean-up of any spilled oil and for pipeline repair.

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, June, July and August of 2009, June, August, and September 2010, February 2011, February to August of 2012 and October 2012 to April 2015, as a result of sabotage by guerrillas. In addition, there is competition for space in these pipelines, and additional discoveries in our area of operations by other companies could decrease the pipeline capacity available to us. Trucking is an alternative to transportation by pipeline; however, it is generally more expensive and carries higher safety risks for us, our employees and the public.

Alternative transportation arrangements in Colombia allowed us to deliver our full production during 2014 and the first three months of 2015; however, these deliveries result in reduced realized prices compared to the Ecopetrol operated OTA pipeline deliveries and are not necessarily sustainable. When disruptions are of a long enough duration, our sales volumes may be lower than normal, which will cause our cash flow to be lower than normal, and if our storage facilities become full, we can be forced to reduce production.

In Peru, any oil produced may be delivered via river barge. Suppliers of barges that meet our high standards for safety and reliability are limited and this may affect our ability to deliver the production volumes we have planned for the test.

Our Oil Sales Will Depend on a Relatively Small Group of Customers, Which Could Adversely Affect Our Financial Results.

During the year ended December 31, 2014, and the three months ended March 31, 2015, our oil sales were to Ecopetrol, one other main customer and three other customers. While oil prices in Colombia are related to international market prices, lack of competition and reliance on a limited number of customers for sales of oil may diminish prices and depress our financial results.

In Brazil, there are a number of potential customers for our oil and we are working to establish relationships with as many as possible to ensure a stable market for our oil. Currently, all of our production in Brazil is sold to Petróleo Brasileiro S.A ("Petrobras"). Petrobras' refinery in the area of our operations has previously had some technical difficulties which have restricted its ability to receive deliveries. This could mean that we cannot produce to full capacity in the area because of restrictions in being able to deliver our oil.

Our Business is Subject to Local Legal, Political and Economic Factors Which Are Beyond Our Control, Which Could Impair Our Ability to Expand Our Operations or Operate Profitably.

We operate our business in Colombia, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as nationalization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. Our production in Brazil was shut in for three weeks in October 2013 as a result of a strike by employees of Petrobras which affected the crude oil receiving terminal we use in the Recôncavo Basin, and we experienced minor delays in trucking operations due to demonstrations and strikes in our operating area during the year ended December 31, 2014. We do not know how long any such labor action will last, and if it lasts a significant amount of time, it may affect our ability to meet our production targets.

South America has a history of political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including the imposition of additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Colombia, Peru or Brazil or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

Changes in laws in the jurisdiction in which we operate or expand into with the effect of favoring local enterprises, and changes in political views regarding the exploitation of natural resources and economic pressures, may make it more difficult for us to negotiate agreements on favorable terms, obtain required licenses, comply with regulations or effectively adapt to adverse economic changes, such as increased taxes, higher costs, inflationary pressure and currency fluctuations. In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for business. These licenses and agreements may be susceptible to revision or cancellation and legal redress may be uncertain or delayed.

Recently, in the Department of Putumayo in Colombia where we operate, despite a company's compliance with legislative requirements for prior consultation of communities and minority ethnic groups and the receipt of the necessary permits to drill and operate, new ethnic groups have been threatening, and in some cases using, the Judicial Branch of the Government, Superior Court of the Judicial District of Mocoa (the "Local Court") to require that they be consulted, and thereby obtain benefits from companies operating in the Department of Putumayo as a result of those consultations. The Local Court has the ultimate jurisdiction to determine, upon a writ for protection or tutela, by an ethnic group (i) whether there has been a violation of a fundamental right to prior consultation by act or omission of a public authority or individual and (ii) whether the ethnic group is legitimate. If the Local Court determines that there has been a violation and the ethnic group is legitimate despite receipt by the company of its proper governmental permits, the Local Court has the power to invalidate a company’s permits and force the company to cease operations immediately until such time as the company can successfully appeal to the Supreme Court to overturn the Local Court’s decision or prior consultations are completed and the permits effective once again.

Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government and judicial authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired and, if we are faced with a tutela, our operations in the area(s) governed by a Local Court’s order may be shut down for a period of time thereby causing significant harm to our business in Colombia.

Recently in Brazil, environmental regulations related to fracture stimulation drilling have been under review by national agencies. In December 2014, the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") issued an injunction specifically related to properties in the Recôncavo Basin covered by Bid Round 12. This injunction placed a moratorium on unconventional activities on the Bid Round 12 blocks, all of which were unconventional exploration targets, until such a time as policies governing unconventional activities are finalized. Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 were granted in Bid Round 9, for which there has not been a similar injunction; however, we expect that the ANP's injunction may limit our ability to receive permits in the short-term for our blocks with unconventional exploration targets. We acquired Blocks REC-T-86, REC-T-117 and REC-T-118 in Bid Round 11 and these blocks may be affected by the same or a similar injunction as the one placed on blocks acquired in Bid Round 12. Until this situation is resolved, the expansion of our drilling operations in Brazil may be limited which would harm our business in Brazil.

Almost All of Our Cash and Cash Equivalents is Held Outside of Canada and the United States, and if We Determine to, or Are Required to, Repatriate These Funds, We Could Be Subject to Significant Taxes.

At March 31, 2015, 82% of our cash and cash equivalents was held by subsidiaries and partnerships outside of Canada and the United States. This cash is generally not available to fund domestic or head office operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay taxes in certain jurisdictions on the distribution of accumulated earnings.

Strategic and Business Relationships Upon Which We May Rely Are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.

Our ability to successfully bid on and acquire additional properties, to discover reserves, to participate in drilling opportunities and to identify and enter into commercial arrangements will depend on developing and maintaining effective working relationships with industry participants and on our ability to select and evaluate suitable partners and to consummate transactions in a highly competitive environment. These relationships are subject to change and may impair our ability to grow.

To develop our business, we enter into strategic and business relationships, which may take the form of joint ventures with other parties or with local government bodies, or contractual arrangements with other oil and gas companies, including those that supply equipment and other resources that we will use in our business. We also have an active business development program to develop those relationships and foster new relationships. We may not be able to establish these business relationships, or if established, we may choose the wrong partner or we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to take to fulfill our obligations to these partners or maintain our relationships. If we fail to make the cash calls required by our joint venture partners in the joint ventures we do not operate, we may be required to forfeit our interests in these joint ventures. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

In cases where we are the operator, our partners may not be able to fulfill their obligations, which would require us to either take on their obligations in addition to our own, or possibly forfeit our rights to the area involved in the joint venture. In addition, despite our partner's failure to fulfill its obligations, if we elect to terminate such relationship, we may be involved in litigation with such partners or may be required to pay amounts in settlement to avoid litigation despite such partner's failure to perform. Alternatively, our partners may be able to fulfill their obligations, but will not agree with our proposals as operator of the property. In this case there could be disagreements between joint venture partners that could be costly in terms of dollars, time, deterioration of the partner relationship, and/or our reputation as a reputable operator. These joint venture partners may not comply with their responsibilities or may engage in conduct that could result in liability to us.

In cases where we are not the operator of the joint venture, the success of the projects held under these joint ventures is substantially dependent on our joint venture partners. The operator is responsible for day-to-day operations, safety, environmental compliance and relationships with government and vendors.

We have various work obligations on our blocks that must be fulfilled or we could face penalties, or lose our rights to those blocks if we do not fulfill our work obligations. Failure to fulfill obligations in one block can also have implications on the ability to operate other blocks in the country ranging from delays in government process and procedure to loss of rights in other blocks or in the country as a whole. Failure to meet obligations in one particular country may also have an impact on our ability to operate in others.

Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations

Our production is subject to royalty obligations which may be prescribed by government regulation or by contract. These royalty obligations may be subject to changes in interpretation as business circumstances change.

As discussed in Note 12 to the Consolidated Financial Statements in Part II, Item 8 below, our production from the Costayaco Exploitation Area is subject to the HPR royalty, which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Contract and the sales price. The ANH has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which we contested because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. We also believe that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have initiated the dispute resolution process under the Chaza Contract by filing on January 14, 2013, an arbitration claim before the Center for Arbitration and Conciliation of the Chamber of Commerce of Bogotá, Colombia, seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. We supplemented our claim on May 30, 2013. The ANH has filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that we breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. We filed a response to the ANH's counterclaim and filed our comments on the ANH defense to our claim. The ANH filed an amended counterclaim and we filed a response to the ANH's amended counterclaim. As at March 31, 2015, total cumulative production from the Moqueta Exploitation Area was 4.8 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $65.6 million plus related interest of $21.3 million. We also disagree with the interest rate that the ANH has used in calculating the interest cost. We assert that since the HPR royalty is denominated in the U.S. dollar, the contract requires the interest rate to be three-month LIBOR plus 4%, whereas the ANH has applied the highest legally authorized interest rate on Colombian peso liabilities, which during the period of production to date has averaged approximately 29% per annum. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed HPR royalty as we do not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on our understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $41.2 million as at March 31, 2015. At this time no amount has been accrued in the financial statements as we do not consider it probable that a loss will be incurred.

Our Business May Suffer if We do Not Attract and Retain Talented Personnel.

Our success will depend in large measure on the abilities, expertise, judgment, discretion, integrity and good faith of our executive team and other personnel in conducting our business. The loss of any of these individuals or our inability to attract suitably qualified individuals to replace any of them could materially adversely impact our business. We have experienced difficulties in the past in finding and retaining suitably qualified staff in certain jurisdictions, particularly in Brazil and Peru, where experienced personnel in our industry are in high demand and competition for their talents is intense.

Our success depends on the ability of our management and employees to interpret market and geological data successfully and to interpret and respond to economic, market and other business conditions to locate and adopt appropriate investment opportunities, monitor such investments and ultimately, if required, successfully divest such investments. Further, our key personnel may not continue their association or employment with us and we may not be able to find replacement personnel with comparable skills. If we are unable to attract and retain key personnel, our business may be adversely affected.

Maintaining Good Community Relationships and Being a Good Corporate Citizen May Be Costly and Difficult to Manage.

Our operations have a significant effect on the areas in which we operate. To enjoy the confidence of local populations and the local governments, we must invest in the communities where were operate. In many cases, these communities are impoverished and lack many resources taken for granted in North America. The opportunities for investment are large, many and varied; however, we must invest carefully in projects that will truly benefit these areas. Improper management of these investments and relationships could lead to a delay in operations, loss of license or major impact to our reputation in these communities, which could adversely affect our business.

Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business.

The oil and gas industry is highly competitive. Other oil and gas companies will compete with us by bidding for exploration and production licenses and other properties and services we will need to operate our business in the countries in which we expect to operate. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies, which, in particular, may have access to greater resources than us, may be more successful in the recruitment and retention of qualified employees and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. In the event that we do not succeed in negotiating additional property acquisitions, our future prospects will likely be substantially limited, and our financial condition and results of operations may deteriorate.

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. We are also exposed to transaction risk on settlement of payables and receivables denominated in foreign currency. We have purchased non-deliverable foreign exchange contracts to hedge some of the transaction risk related to our Colombian income tax payable. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Production in Brazil is invoiced and paid in Brazilian Reals. Between September 1, 2005, and May 1, 2015, the exchange rate of the Brazilian Real has varied between 1.56 Reals to one U.S. dollar to 3.29 Reals to the U.S. dollar, a variance of 76%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the Colombian peso weakened by 8% against the U.S. dollar in the three months ended March 31, 2015, resulting in a foreign exchange gain.

Our Operations Involve Substantial Costs and Are Subject to Certain Risks Because the Oil and Gas Industries in the Countries in Which We Operate Are Less Developed.

The oil and gas industry in South America is not as efficient or developed as the oil and gas industry in North America. As a result, our exploration and development activities may take longer to complete and may be more expensive than similar operations in North America. The availability of technical expertise, specific equipment and supplies may be more limited than in North America. We expect that such factors will subject our international operations to economic and operating risks that may not be experienced in North American operations.

Further, we operate in remote areas and may rely on helicopter, boats or other transportation methods. Some of these transport methods may result in increased levels of risk and could lead to operational delays which could effect our ability to add to our reserve base and/or produce oil, serious injury or loss of life and could have a significant impact on our reputation or cash flow. Additionally, some of this equipment is specialized and may be difficult to obtain in our areas of operations, which could hamper or delay operations, and could increase the cost of those operations.

Exchange Controls and New Taxes Could Materially Affect Our Ability to Fund Our Operations and Realize Profits from Our Foreign Operations.

Foreign operations may require funding if their cash requirements exceed operating cash flow. To the extent that funding is required, there may be exchange controls limiting such funding or adverse tax consequences associated with such funding. In addition, taxes and exchange controls may affect the dividends that we receive from foreign subsidiaries.

The government in Brazil requires us to register funds that enter and exit the country with the central bank. In Brazil and Colombia, all transactions must be carried out in the local currency of the country. Exchange controls may prevent us from transferring funds abroad.

In Colombia, we participate in a special exchange regime, which allows us to receive revenue in U. S. dollars offshore. This regime gives us flexibility to determine the currency in which we receive our revenues, rather than to be restricted to Colombian pesos if received in Colombia, but also limits the ways in which we are able to fund our operations in Colombia. As such, this could cause us to employ funding strategies for our Colombian operations that are not as tax efficient as might otherwise be possible if we did not participate in the special exchange regime.

Tax law changes can impact the after tax profits available for expatriation. For example, in the fourth quarter of 2014 the Colombian government approved tax legislation increasing the rate of tax applicable to ordinary income from 34% in 2014 to 39% for 2015, 40% for 2016, 42% for 2017 and 43% for 2018. In the same legislation, the Colombian government also instituted a new “wealth tax” payable on the net equity of our Colombia business units at a rate of 1.15% for 2015, 1% for 2016 and 0.4% for 2017.

We May Be Unable to Obtain Additional Capital That We Will Require to Implement Our Business Plan, Which Could Restrict Our Ability to Grow.

We expect that our cash flow from existing operations and cash on hand will be sufficient to fund our currently planned activities. We may require additional capital to expand our exploration and development programs to additional properties. We may be unable to obtain additional capital required.

When we require additional capital, we plan to pursue sources of capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. We may not be successful in locating suitable financing transactions in the time period required or at all, and we may not obtain the capital we require by other means. If we do succeed in raising additional capital, future financings may be dilutive to our shareholders, as we could issue additional shares of Common Stock or other equity to investors. In addition, debt and other mezzanine financing may involve a pledge of assets and may be senior to interests of equity holders. We may incur substantial costs in pursuing future capital financing, including investment banking fees, legal fees, accounting fees, securities law compliance fees, printing and distribution expenses and other costs. We may also be required to recognize non-cash expenses in connection with certain securities we may issue, such as convertibles and warrants, which will adversely impact our financial results.

Our ability to obtain needed financing may be impaired by factors such as the capital markets (both generally and for the oil and gas industry in particular), the location of our oil and natural gas properties in South America, prices of oil and natural gas on the commodities markets (which will impact the amount of asset-based financing available to us), and the loss of key management. Further, if oil and/or natural gas prices on the commodities markets decrease, then our revenues will likely decrease, and such decreased revenues may increase our requirements for capital. The price of oil and natural gas also effects the value of our oil and natural gas reserves, which dictates our capacity to borrow using those reserves as collateral. Some of the contractual arrangements governing our exploration activity may require us to commit to certain capital expenditures, and we may lose our contract rights if we do not have the required capital to fulfill these commitments. If the amount of capital we are able to raise from financing activities, together with our cash flow from operations, is not sufficient to satisfy our capital needs (even to the extent that we reduce our activities), we may be required to curtail our operations.

Negative Political Developments in Colombia May Negatively Affect Our Proposed Operations.

Adverse political incidents may generate social unrest which could impact our operations and oil deliveries in Colombia. Peace process negotiations between the government and FARC may not generate the intended outcome for both parties. With the use of arms, and other methods of influence, the FARC may place pressure on organizations and communities that are in areas of operations of the company. These communities, and affiliated organizations, can generate protests to attract the attention of government. These communities may make further use of the Local Court by filing a tutela, or writ of protection, to stop operations in Colombia until such time as these new ethnic communities obtain further consultations and benefits from companies operating in Colombia. Protests or other demonstrations may establish blockades, or the issuance of a tutela by a Local Court, could cause interruptions of operations, deliveries, and other disruptions to our capital programs in the affected area.

Negative Political Developments in Peru May Negatively Affect our Proposed Operations.

Peru held a national election in June 2011 after which a new political regime was elected on a left-populist platform. The government has said that the past decade prioritized the strengthening of democracy with economic growth, while the current government will enhance social inclusion to benefit the neediest. This political regime may adopt new policies, laws and regulations that are more hostile toward foreign investment which may result in the imposition of additional taxes, the adoption of regulations that limit price increases, termination of contract rights, or the expropriation of foreign-owned assets. Such actions by the elected political regime could limit the amount of our future revenue in that country and affect our results of operations.

Guerrilla Activity in Peru Could Disrupt or Delay Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Peru.

The Shining Path Guerilla group has been active in Peru since the early 1980's and, at one point, was active throughout the country. Recently, the group's activity has been confined to small areas of Peru and operations have been hampered by the capture of many high profile leaders and membership has fallen dramatically. During April 2012, 30 people working on the Camisea natural gas project in central Peru were kidnapped. Most of the workers were released after a short period of time, and the remainder were freed within a few days. The kidnapping was attributed to the Shining Path Guerilla group. Camisea is a very large, high profile project in an area where the group continues to be active. Our operations in Peru are in a different region, with no known activity by the group. Other groups may be active in other areas of the country and possibly our operational areas. Recently there have been security incidents and incidents of social unrest in and around our operating areas, particularly Block 107. We are monitoring the situation and increasing security measures as required. Nevertheless, we are concerned about the security of our operations in Peru and mitigate our risks through good relationships with local communities and stakeholders as well as strong security procedures.

We May Not Be Able to Effectively Manage Our Growth, Which May Harm Our Profitability.

Our strategy envisions continually expanding our business, both organically and through acquisition of other properties and companies. If we fail to effectively manage our growth or integrate successfully our acquisitions, our financial results could be adversely affected. Growth may place a strain on our management systems and resources. Integration efforts place a significant burden on our management and internal resources. The diversion of management attention and any difficulties encountered in the integration process could harm our business, financial condition and results of operations. In addition, we must continue to refine and expand our business development capabilities, our systems and processes and our access to financing sources. As we grow, we must continue to hire, train, supervise and manage new or acquired employees. We may not be able to:

- expand our systems effectively or efficiently or in a timely manner;
- allocate our human resources optimally;
- identify and hire qualified employees or retain valued employees; or
- incorporate effectively the components of any business that we may acquire in our effort to achieve growth.

If we are unable to manage our growth and our operations our financial results could be adversely affected by inefficiencies, which could diminish our profitability.

The United States Government May Impose Economic or Trade Sanctions on Colombia That Could Result In a Significant Loss to Us.

Colombia is among several nations whose eligibility to receive foreign aid from the United States is dependent on its progress in stemming the production and transit of illegal drugs, which is subject to an annual review by the President of the United States. Although Colombia is currently eligible for such aid, Colombia may not remain eligible in the future. A finding by the President that Colombia has failed demonstrably to meet its obligations under international counternarcotics agreements may result in any of the following:

- all bilateral aid, except anti-narcotics and humanitarian aid, would be suspended;

- the Export-Import Bank of the United States and the Overseas Private Investment Corporation would not approve financing for new projects in Colombia;
- United States representatives at multilateral lending institutions would be required to vote against all loan requests from Colombia, although such votes would not constitute vetoes; and
- the President of the United States and Congress would retain the right to apply future trade sanctions.

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with ANH and Ecopetrol and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on

Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets.

Accordingly, the imposition of the foregoing economic and trade sanctions on Colombia would likely result in a substantial loss and a decrease in the price of shares of our Common Stock. The United States may impose sanctions on Colombia in the future, and we cannot predict the effect in Colombia that these sanctions might cause.

We Are Subject to the U.S. Foreign Corrupt Practices Act, a Violation of Which Could Adversely Affect Our Business.

The U.S. Foreign Corrupt Practices Act ("FCPA") and similar anti-bribery laws in other jurisdictions prohibit corporations and individuals, including us and our employees, from making improper payments to non-U.S. officials and certain other individuals and organizations for the purpose of obtaining or retaining business or engaging in certain accounting practices. We do business and may do future business in countries in which we may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations, international organizations, or private entities. As a result, we face the risk of unauthorized payments or offers of payments by employees, contractors and agents of ours or our subsidiaries or affiliates, even though these parties are not always subject to our control or direction. It is our policy to implement compliance procedures to prohibit these practices. However, our existing safeguards and any future improvements may prove to be less than effective or may not be followed, and our employees, contractors, agents, and partners may engage in illegal conduct for which we might be held responsible. Also, the FCPA contains certain accounting standards which obligate us to maintain accurate and complete books and records and a system of effective internal controls. These accounting provisions are very broad and a violation can occur even if there is no evidence of a bribe. The U.S. government is actively investigating and enforcing the FCPA and similar laws against companies and individuals. A violation of any of these laws, even if prohibited by our policies, may result in criminal or civil sanctions or other penalties (including profit disgorgement), could disrupt our business and could have a material adverse effect on our business. Actual or alleged violations could damage our reputation, be expensive to investigate and defend, and impair our ability to do business. A number of countries, including Canada, have strengthened their anti-corruption legislation. These laws prohibit both domestic and international bribery. There is a risk that an act of corruption can result in a violation of not only the FCPA, but also the laws of several other countries.

Our Business Could Be Negatively Impacted by Security Threats, Including Cybersecurity Threats as Well as Other Disasters, and Related Disruptions.

Our business processes depend on the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure in response to our changing needs. It is critical to our business that our facilities and infrastructure remain secure. Although we employ data encryption processes, an intrusion detection system, and other internal control procedures to assure the security of our data, we cannot guarantee that these measures will be sufficient for this purpose. The ability of the information technology function to support our business in the event of a security breach or a disaster such as fire or flood and our ability to recover key systems and information from unexpected interruptions cannot be fully tested and there is a risk that, if such an event actually occurs, we may not be able to address immediately the repercussions of the breach or disaster. In that event, key information and systems may be unavailable for a number of days or weeks, leading to our inability to conduct business or perform some business processes in a timely manner. We have implemented strategies to mitigate impacts from these types of events.

We have expended significant time and money on the security of our facilities and on our information technology infrastructure including testing of our security at our facilities and infrastructure. If our security measures are breached as a result of third-party action, employee error or otherwise, and as a result our data becomes available to unauthorized parties, we may lose our competitive edge in certain of our business activities and our reputation may be damaged. If we experience any breaches of our network security or sabotage, we might be required to expend significant capital and other resources to remedy, protect against or alleviate these and related problems, and we may not be able to remedy these problems in a timely manner, or at all. Because techniques used by outsiders to obtain unauthorized network access or to sabotage systems change frequently and generally are not recognized until launched against a target, we may be unable to anticipate these techniques or implement adequate preventative measures.

We have had past security breaches to our infrastructure, and, although they did not have a material adverse effect on our operations or our operating results, there can be no assurance of a similar result in the future. Our employees have been and will continue to be targeted by parties using fraudulent “spoof” and “phishing” emails to misappropriate information or to introduce viruses or other malware through “trojan horse” programs to our computers. These emails appear to be legitimate emails sent by us but direct recipients to fake websites operated by the sender of the email or request that the recipient send a password or other confidential information through email or download malware. Despite our efforts to mitigate “spoof” and "phishing" emails through education, "spoof" and "phishing" activities remain a serious problem that may damage our information technology infrastructure.

Risks Related to Our Industry

Unless We Are Able to Replace Our Reserves, and Develop and Manage Oil and Gas Reserves and Production on an Economically Viable Basis, Our Reserves, Production and Cash Flows May Decline as a Result.

Our future success depends on our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We may not be able to find, develop or acquire additional reserves at acceptable costs.

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs.

Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and technical conditions. While we will endeavor to effectively manage these conditions, we may not be able to do so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

Estimates of probable and possible reserves are inherently imprecise. When producing an estimate of the amount of oil that is recoverable from a particular reservoir, probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. Estimates of probable and possible reserves are by their nature much more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

In addition, the quantity and value of our reserves directly effects our ability to access certain kinds of external financing that uses our reserves as collateral. Low oil prices diminish the value of our oil reserves, thus diminishing not only current cash flow, but debt capacity and access to other forms of capital as well. This could impair our ability to carry out the exploration and development activity required to replace our reserves.

Prices and Markets for Oil and Natural Gas Are Unpredictable and Tend to Fluctuate Significantly, Which Could Reduce Our Profitability, Growth and Value.

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for West Texas Intermediate ("WTI") per bbl has varied from $66 in 2006 to $98 in 2013, $93 in 2014 and $49 in the three months ended March 31, 2015, demonstrating the inherent volatility in the market. The average Brent oil price per bbl was $111 in 2011, $112 in 2012, $109 in 2013, $99 in 2014 and $54 in the three months ended March 31, 2015. Given the current economic environment and unstable conditions in the Middle East, North Africa, and Eastern Europe and the current supply of oil in world markets, the oil price environment is unpredictable and unstable. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations, financing available to us, and quantities of reserves recoverable on an economic basis.

Oil prices in Colombia are related to international market prices, but adjustments that are defined by contracts with offtakers may cause realized prices to be lower or higher than those received in North America. Oil prices in Brazil are defined by contract with the refinery and may be lower or higher than those received in North America.

Our Exploration for Oil and Natural Gas Is Risky and May Not Be Commercially Successful, Impairing Our Ability to Generate Revenues from Our Operations.

Oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our exploration expenditures may not result in new discoveries of oil or natural gas in commercially viable quantities or at a commercially viable cost. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. For example, in January 2014, the Corunta-1 exploration well on the west flank of the Moqueta field encountered drilling problems prior to reaching the reservoir target on this long-reach deviated well, and the decision was made to abandon the well. The target location may be drilled again in the future with a revised drilling plan. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations. In addition, changes in the price of oil can affect the commercial success of our exploration activity. If the oil price declines drastically, such as it did at the end of 2014 and beginning of 2015, some projects that were previously considered commercially successful may not be at low oil price levels and may be deferred, which means that our short to medium term production and cash flow may be lower than previously anticipated. For example, largely as a result of the current low commodity price environment, we reevaluated our business strategy with a renewed focus on balancing the return and risk of our exploration and development projects. As a result, on February 19, 2015, we made the decision to cease all further development expenditures on the Bretaña field on Block 95 in Peru other than what is necessary to maintain tangible asset integrity and security. The high capital investment, associated debt financing and long-term payout horizon of this project does not align with our shift in strategy as announced on February 2, 2015. Considering the current low commodity price environment and the significant aspects of the Bretaña field project which were no longer in line with our strategy, our Board of Directors determined that they would not proceed with the further capital investment required to develop the Bretaña field. As a result of this decision, all probable and possible reserves associated with the field were reclassified as contingent resources in a report with an effective date of January 31, 2015. Further as a result, $265.1 million of unproved properties relating to Block 95 were impaired at December 31, 2014, and an additional impairment loss of $32.7 million relating to the remaining costs on Block 95 was incurred in the first quarter of 2015. We expect to continue to identify and evaluate all options for the Bretaña field.

Estimates of Oil and Natural Gas Reserves That We Make May Be Inaccurate and Our Actual Revenues May Be Lower and Our Operating Expenses May Be Higher Than Our Financial Projections.

We make estimates of oil and natural gas reserves, upon which we will base our financial projections. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Wells that are drilled may not achieve the results expected from interpretation of geological data. Economic factors beyond our control, such as world oil prices, interest rates and exchange rates, will also impact the value of our reserves. The process of estimating oil and gas reserves is complex, and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

Exploration, development, production (including transportation and workover costs), marketing (including distribution costs) and regulatory compliance costs (including taxes) will substantially impact the net revenues we derive from the oil and gas that we produce. These costs are subject to fluctuations and variation in different locales in which we operate, and we may not be able to predict or control these costs. If these costs exceed our expectations, this may adversely affect our results of operations. In addition, we may not be able to earn net revenue at our predicted levels, which may impact our ability to satisfy our obligations.

If Oil and Natural Gas Prices Decrease, or Our Operating Results are Different Than We Expect, We May Be Required to Take Write-Downs of the Carrying Value of Our Oil and Natural Gas Properties.

We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. 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. The net book value is compared with the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense. Under full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings. In countries where we do not have proved reserves, dry wells drilled in a period would directly result in an impairment for that period.

In 2012, we recorded a ceiling test impairment loss of $20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. The farm-out agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period. In 2013, we recorded a $2.0 million ceiling test impairment loss in our Brazil cost center related to lower realized prices and an increase in operating costs. In the year ended December 31, 2013, we recorded a ceiling test impairment loss of $30.8 million in our Argentina cost center as a result of deferred investment and inconclusive waterflood results. In 2014, we recorded an impairment loss of $265.1 million in our Peru cost center related to drilling costs on Block 95, and an additional impairment loss of $32.7 million relating to the remaining drilling costs for the Bretaña Sur 95-3-4-1X appraisal well and other costs related to Block 95 was incurred in the first quarter of 2015. Additionally, in the first quarter of 2015 we recorded a $4.3 million ceiling test impairment loss in our Brazil cost center related to lower oil prices.

We Are Required to Obtain Licenses and Permits to Conduct Our Business and Failure to Obtain These Licenses Could Cause Significant Delays and Expenses That Could Materially Impact Our Business.

We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. For example, the permitting process in Peru takes significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere. In Colombia, other drilling and development projects are being delayed, most significantly our Moqueta field development, because of delays at the Ministry of the Environment and other government departments. During the third quarter 2014, we received the Exploitation License for the Moqueta field, however delays in receiving it contributed to operational delays and higher development costs. In addition, environmental and social evaluation demands have increased in Colombia, causing permit processing to take longer than previously experienced in the areas where we operate and, in some areas where we operate, such as the Department of Putumayo, despite the receipt of the proper permits, there are new procedures being utilized by new ethnic communities to make further economic demands on operators to continue to operate in the region, such as the use of the Local Court to obtain a tutela, or writ of protection. These delays and demands are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations. For example, currently in Brazil, we are subject to restrictions on flaring natural gas, which have the impact of limiting our production capacity. We have examined other alternatives for producing and delivering the gas, however, however, to date, we have not been able to successfully implement any of these alternatives. Also in Brazil, we have had operations on our Tiê field suspended since March 12, 2015, due 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. We have carried out the remedial actions required and now await ANP approval to resume operations.

Our Inability to Obtain Necessary Facilities and/or Equipment Could Hamper Our Operations.

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment, transportation, power and technical support in the particular areas where these activities will be conducted, and our access to these facilities may be limited. To the extent that we conduct our activities in remote areas, needed facilities or equipment may not be proximate to our operations, which will increase our expenses. For example, our development and exploration projects in Peru are in remote areas that require barge and helicopter transportation which adds dramatically to the cost of these operations. Demand for such limited equipment and other facilities or access restrictions may affect the availability of such equipment to us and may delay exploration and development activities. The quality and reliability of necessary facilities or equipment may also be unpredictable and we may be required to make efforts to standardize our facilities, which may entail unanticipated costs and delays. Shortages and/or the unavailability of necessary equipment, transportation or other facilities will impair our activities, either by delaying our activities, increasing our costs or otherwise.

Decommissioning Costs Are Unknown and May Be Substantial; Unplanned Costs Could Divert Resources from Other Projects.

We are responsible for costs associated with abandoning and reclaiming some of the wells, facilities and pipelines which we use for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as “decommissioning.” We have determined that we require a reserve account for these potential costs in respect of our current properties and facilities at this time, and have booked such reserve on our financial statements. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy decommissioning costs could impair our ability to focus capital investment in other areas of our business. For example, our decision to not commit to further investment in the Bretaña field on Block 95 in Peru could accelerate the timing of significant decommissioning costs.

Drilling New Wells and Producing Oil and Natural Gas From Existing Facilities Could Result in New Liabilities, Which Could Endanger Our Interests in Our Properties and Assets.

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires and spills. Earthquakes or weather related phenomena such as heavy rain, landslides, storms and hurricanes can also cause problems in drilling new wells. There are also risks in producing oil and natural gas from existing facilities. For example, in January 2014, the Corunta-1 exploration well on the west flank of the Moqueta field encountered drilling problems prior to reaching the reservoir target on this long-reach deviated well, and the decision was made to abandon the well. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. Incidents such as these can lead to serious injury, property damage and even loss of life. We generally obtain insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

Environmental Risks May Adversely Affect Our Business.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require us to incur costs to remedy such discharge. For example, we have encountered difficulties maintaining the stability of the river shoreline at our drilling and production facilities at the Bretaña field on Block 95. We will have to invest money to remediate the shoreline even though we have suspended investment in the field while we evaluate options. The application of environmental laws to our business may cause us to curtail our production or increase the costs of our production, development or exploration activities.

Penalties We May Incur Could Impair Our Business.

Our exploration, development, production and marketing operations are regulated extensively under foreign, federal, state and local laws and regulations. Under these laws and regulations, we could be held liable for personal injuries, property damage, site clean-up and restoration obligations or costs and other damages and liabilities. We may also be required to take corrective actions, such as installing additional safety or environmental equipment, which could require us to make significant capital expenditures. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages. We could be required to indemnify our employees in connection with any expenses or liabilities that they may incur individually in connection with regulatory action against them. As a result of these laws and regulations, our future business prospects could deteriorate and our profitability could be impaired by costs of compliance, remedy or indemnification of our employees, reducing our profitability.

Policies, Procedures and Systems to Safeguard Employee Health, Safety and Security May Not Be Adequate.

Oil and natural gas exploration and production is dangerous. Detailed and specialized policies, procedures and systems are required to safeguard employee health, safety and security. We have undertaken to implement best practices for employee health, safety and security; however, if these policies, procedures and systems are not adequate, or employees do not receive adequate training, the consequences can be severe including serious injury or loss of life, which could impair our operations and cause us to incur significant legal liability.

Our Insurance May Be Inadequate to Cover Liabilities We May Incur.

Our involvement in the exploration for and development of oil and natural gas properties may result in our becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although we have insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, we may choose not to obtain insurance to protect against specific risks due to the high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to us. If we suffer a significant event or occurrence that is not fully insured, or if the insurer of such event is not solvent, we could be required to divert funds from capital investment or other uses towards covering our liability for such events.

Challenges to Our Properties May Impact Our Financial Condition.

Title to oil and natural gas interests is often not capable of conclusive determination without incurring substantial expense. While we intend to make appropriate inquiries into the title of properties and other development rights we acquire, title defects may exist. In addition, we may be unable to obtain adequate insurance for title defects, on a commercially reasonable basis or at all. If title defects do exist, it is possible that we may lose all or a portion of our right, title and interest in and to the properties to which the title defects relate.

Furthermore, applicable governments may revoke or unfavorably alter the conditions of exploration and development authorizations that we procure, or third parties may challenge any exploration and development authorizations we procure. Such rights or additional rights we apply for may not be granted or renewed on terms satisfactory to us.

If our property rights are reduced, whether by governmental action or third party challenges, our ability to conduct our exploration, development and production may be impaired. See the risk factor "Disputes or Uncertainties May Arise in Relation to Our Royalty Obligations" for a description of our dispute with the ANH regarding royalties payable on our Chaza Block and the resulting challenge to our contract for that block.

We Will Rely on Technology to Conduct Our Business and Our Technology Could Become Ineffective or Obsolete.

We rely on technology, including geographic and seismic analysis techniques and economic models, to develop our reserve estimates and to guide our exploration and development and production activities. We will be required to continually enhance and update our technology to maintain its efficacy and to avoid obsolescence. The costs of doing so may be substantial, and may be higher than the costs that we anticipate for technology maintenance and development. If we are unable to maintain the efficacy of our technology, our ability to manage our business and to compete may be impaired. Further, even if we are able to maintain technical effectiveness, our technology may not be the most efficient means of reaching our objectives, in which case we may incur higher operating costs than we would were our technology more efficient.

Risks Related to Our Common Stock

* The Proxy Contest Initiated by a Dissident Stockholder has the Potential to Adversely Affect Our Business and the Market Price of Our Common Stock.

West Face Capital, Inc., or West Face, has initiated a proxy contest with respect to the matters to be voted upon at our 2015 annual meeting of stockholders, or the Annual Meeting. Among other things, West Face is proposing to solicit proxies in opposition to us for the purpose of voting in favor of its six nominees for election to our board of directors. West Face communicated to us, and states explicitly, that the board of directors should replace our chief executive officer. Our business, operating results or financial condition could be harmed by the proxy contest because, among other things:

- responding to the proxy contest is costly and time-consuming, is a significant distraction for our board of directors, management and employees and diverts the attention of our board of directors and senior management from the pursuit of our business strategy, which could adversely affect our results of operations and financial condition.
- perceived uncertainties as to our future direction, our ability to execute on our strategy, or changes to the composition of our board of directors or senior management team, including our chief executive officer, may lead to the perception of a change in the direction of our business, instability or lack of continuity which may be exploited by our competitors, and may result in the loss of potential business opportunities and make it more difficult to attract and retain qualified personnel and business partners.
- we may choose to initiate or may become subject to, litigation as a result of the proxy contest or matters arising from the proxy contest, which would serve as a further distraction to our board of directors, management and employees and would require us to incur significant additional costs.

In addition, the market price of our common stock could be subject to significant fluctuation or otherwise be adversely affected by the uncertainties described above, the outcome of the proxy contest, or a threat of future stockholder activism.

The Market Price of Our Common Stock May Be Highly Volatile and Subject to Wide Fluctuations.

The market price of shares of our Common Stock may be highly volatile and could be subject to wide fluctuations in response to a number of factors that are beyond our control, including but not limited to:

- dilution caused by our issuance of additional shares of Common Stock and other forms of equity securities, which we expect to make in connection with acquisitions of other companies or assets;
- announcements of new acquisitions, reserve discoveries or other business initiatives by our competitors;
- fluctuations in revenue from our oil and natural gas business;
- changes in the market and/or WTI or Brent price for oil and natural gas commodities and/or in the capital markets generally, or under our credit agreement;
- changes in the demand for oil and natural gas, including changes resulting from the introduction or expansion of alternative fuels;
- changes in the social, political and/or legal climate in the regions in which we will operate;
- changes in the valuation of similarly situated companies, both in our industry and in other industries;

- changes in analysts’ estimates affecting us, our competitors and/or our industry;
- changes in the accounting methods used in or otherwise affecting our industry;
- changes in independent reserve estimates related to our oil and gas properties;
- announcements of technological innovations or new products available to the oil and natural gas industry;

- announcements by relevant governments pertaining to incentives for alternative energy development programs;
- fluctuations in interest rates, exchange rates and the availability of capital in the capital markets; and
- significant sales of shares of our Common Stock, including sales by future investors in future offerings we expect to make to raise additional capital.

In addition, the market price of shares of our Common Stock could be subject to wide fluctuations in response to various factors, which could include the following, among others:

- quarterly variations in our revenues and operating expenses and/or results of our operations; and
- additions and departures of key personnel.
- updated reserve estimates by independent parties.
- announcements regarding the proxy contest for our 2015 annual meeting of stockholders or the outcome thereof, as well other actions by stockholder activists;

These and other factors are largely beyond our control, and the impact of these risks, singularly or in the aggregate, may result in material adverse changes to the market price of shares of our Common Stock and/or our results of operations and financial condition.

We do Not Expect to Pay Dividends in the Foreseeable Future.

We do not intend to declare dividends for the foreseeable future, as we anticipate that we will reinvest any future earnings in the development and growth of our business. Therefore, investors will not receive any funds unless they sell their shares of Common Stock, and shareholders may be unable to sell their shares on favorable terms or at all. Investors cannot be assured of a positive return on investment or that they will not lose the entire amount of their investment in shares of our Common Stock.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds

On February 26, 2015, we issued 885,738 shares of our common stock to one holder of exchangeable shares, Verne Johnson, which were issued by a subsidiary of Gran Tierra in a share exchange on November 10, 2005. The shares were issued to this holder in reliance on Regulation S promulgated by the SEC as the investor was not a resident of the United States.

Item 6. Exhibits

See Index to Exhibits at the end of this Report, which is incorporated by reference here. The Exhibits listed in the accompanying Index to Exhibits are filed as part of this report.

SIGNATURES

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

GRAN TIERRA ENERGY INC.

Date: May 6, 2015	/s/ Jeffrey Scott By: Jeffrey Scott Executive Chairman of the Board, Director (Principal Executive Officer)
Date: May 6, 2015	/s/ Duncan Nightingale By: Duncan Nightingale Interim President and Chief Executive Officer (Principal Executive Officer)
Date: May 6, 2015	/s/ James Rozon By: James Rozon Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1	Arrangement Agreement, dated as of July 28, 2008, by and among Gran Tierra Energy Inc., Solana Resources Limited and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on August 1, 2008 (SEC File No. 001-34018).
2.2	Amendment No. 2 to Arrangement Agreement, which supersedes Amendment No. 1 thereto and includes the Plan of Arrangement, including appendices.	Incorporated by reference to Exhibit 2.2 to the Registration Statement on Form S-3, filed with the SEC on October 10, 2008 (SEC File No. 333-153376).
2.3	Arrangement Agreement, dated January 17, 2011, by and between Gran Tierra Energy Inc. and Petrolifera Petroleum Limited. +	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (SEC File No. 001-34018).
2.4	Share Purchase and Sale Offer, dated May 29, 2014, by Gran Tierra Petroco Inc. +	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on July 1, 2014 (SEC File No. 001-34018).
2.5	Share Purchase and Sale Offer, dated May 29, 2014, by Gran Tierra Energy Inc., an Alberta corporation, and PCESA Petroleros Canadienses De Ecuador S.A. +	Incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K, filed with the SEC on July 1, 2014 (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 February 26, 2014 (SEC File No. 001-34018).
4.1	Reference is made to Exhibits 3.1 to 3.2.	
4.2	Details of the Goldstrike Special Voting Share.	Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.3	Goldstrike Exchangeable Share Provisions.	Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.4	Provisions Attaching to the GTE–Solana Exchangeable Shares.	Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the SEC on October 14, 2008 (SEC File No. 001-34018).

10.1	2014 Executive Officer Cash Bonus Compensation and 2015 Cash Compensation Arrangements.	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 25, 2015, with respect to 2014 Cash Bonus Compensation and 2015 Cash Compensation Arrangements (SEC File No. 001-34018).
10.2	Executive Employment Agreement dated February 2, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Jeffrey Scott	Incorporated by reference to Exhibit 10.26 to the Annual Report on Form 10-K, filed with the SEC on March 2, 2015 (SEC File No. 001-34018).
10.3	Amendment to Executive Employment Agreement dated February 19, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale.	Filed herewith.
31.1	Certification of Principal Executive Officer.	Filed herewith.
31.2	Certification of Principal Financial Officer.	Filed herewith.
31.3	Certification of Principal Executive Officer.	Filed herewith.
32.1	Section 1350 Certifications.	Filed 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.