A Transformed Portfolio

- High Quality Assets
- Large Resource Base
- Visible Production Growth

GranTierra energy inc.

Gran Tierra 2016 Annual Report

A Transformed Portfolio

- 4 Strategic acquisitions in Colombia in 2016 (1)
- Working interest (W.I.) 1P, 2P, 3P reserves before royalties increased 51%, 91% and 146% respectively (2)
- Sustainable business model, expected to be fully funded by forecasted cash from operating activities

High Quality Assets

74% of 2P reserves are in three large, operated, conventional, onshore Colombian oil assets with high netback production (2)

Large Resource Base

Dominant Putumayo Position in emerging N-Sand & A-Limestone oil play fairways

Plans to drill 30-35 exploration wells over the next three years

Control of Operations

Operating 90% of production with significant control and flexibility on capital allocation and timing

Visible Production Growth

Fourth quarter 2016 W.I. production increased 34% over fourth quarter 2015 W.I. production

1P - $2.53 NAV/share (3)
2P - $4.85 NAV/share (3)
3P - $7.84 NAV/share (3)

(1) Three completed acquisitions (Petroamerica, PetroGranada, PetroLatina), one pending (Ecopetrol bid round).

(2) Based on independent reserve reports prepared by McDaniel as of December 31, 2016 & December 31, 2015, in accordance with NI 51-101 & COGEH compliant gross W.I.

(3) See footnote (2), based on number of shares of Gran Tierra's common stock and exchangeable shares issued and outstanding at December 31, 2016 and 2015, of 399.0 million and 282.0 million, respectively. Net working capital deficit and long-term debt at December 31, 2016, and working capital at December 31, 2015, prepared in accordance with generally accepted accounting principles in the United States of America.

Gran Tierra Energy Inc. together with its subsidiaries (“Gran Tierra”) is an independent international energy company focused on oil and gas acquisition, exploration, development and production in Colombia. Gran Tierra is traded on the NYSE MKT and the TSX as “GTE”.

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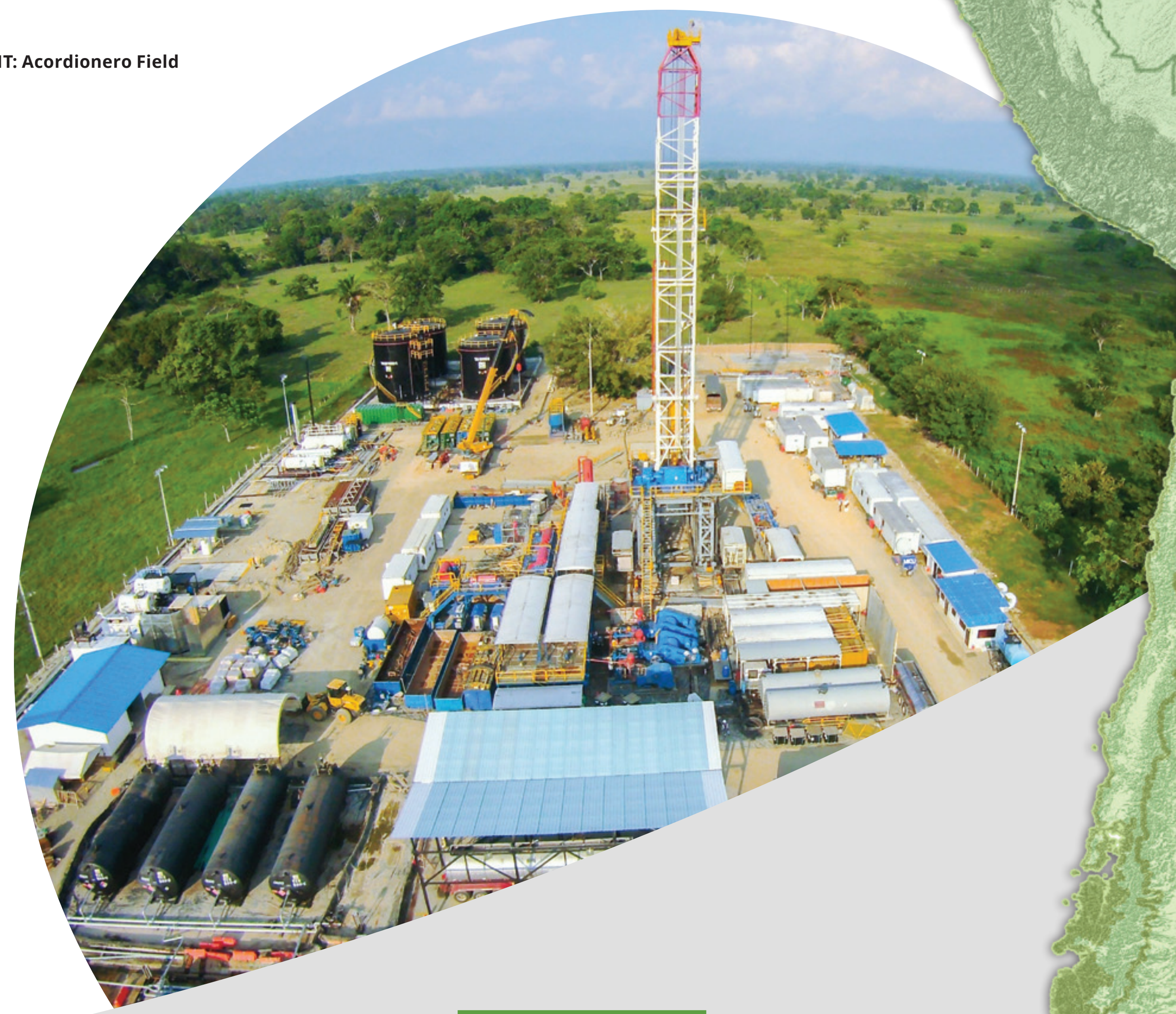
RIGHT: Acordionero Field



Message from the President and CEO

During 2016, Gran Tierra successfully transformed its portfolio by delivering on our strategy of building a high-quality, diversified suite of assets in Colombia with high netback production, low base production declines, an expanded drilling inventory and a large resource base. Now that we have transformed the portfolio, our focus is on execution.

With our delivery of strong production growth in fourth quarter 2016, we are demonstrating that Gran Tierra has created a sustainable business model which we expect to be fully funded point-forward by forecasted cash from operating activities. Since we operate over 90% of our production, Gran Tierra also has significant control and flexibility on capital allocation and timing.

We transformed our portfolio through four strategic, accretive acquisitions in Colombia in 2016 (three completed, one pending), which established a dominant land position in the highly prospective, underexplored Putumayo Basin and a new core area in the prolific Middle Magdalena Valley Basin. Our high quality asset base now has 74% of its 2P reserves contained in three large operated, conventional, onshore Colombian oil assets: Acordionero, Costayaco and Moqueta.

As we reported on January 23, 2017, this transformed portfolio delivered, during 2016, 1P, 2P and 3P W.I. reserves growth of 51%, 91% and 146% respectively, compared to 2015. Our inventory of net undrilled development locations has grown to 36 (2P) and 54 (3P) during the year. We are also pleased that we were able to increase our 2P reserve life index from 7.8 years to 11.1 years. This robust set of assets is now expected to have visibility to 2018 W.I. production greater than 40,000 BOEPD by 2018, based on the 2P forecast. With our large resource base, we also plan to drill 30 to 35 exploration wells over the next three years, which are all expected to be funded by cash from operating activities. Our exploration campaign is designed to test the majority of our portfolio of prospective resources with these wells, including our now dominant Putumayo position in the emerging "N" Sand and "A" Limestone oil play fairways.

We believe Gran Tierra ended 2016 on a strong note by delivering strong production growth in fourth quarter 2016, as we realized the first full three months of production from the PetroLatina acquisition which closed August 23, 2016. Fourth quarter 2016 W.I. production averaged 31,031 BOEPD, an increase of 34% from fourth quarter 2015's level of 23,138 BOEPD and an increase of 20% from the Prior Quarter. Commensurate with our increased production, our funds flow from operations[1] saw a substantial increase of 54% in fourth quarter 2016 to $36.2 million compared with $23.5 million in the Prior Quarter.

Oil prices increased in fourth quarter 2016, with Brent prices averaging $51.13 per barrel, a 9% increase from the Prior Quarter, while Gran Tierra's realized oil price also rose by 9% to $31.89 per BOE in the same time period. Gran Tierra continued to be successful in driving down combined operating and transportation expenses to $11.10 per BOE in the fourth quarter, a decrease of 17% from the Prior Quarter. We believe our low cost structure and growing production base allow us to be successful in a variety of pricing environments. Our ongoing focus on cost reductions allowed us to increase our operating netback in fourth quarter 2016 to $20.79 per BOE, up 31% from the Prior Quarter, a larger increase than the 9% increase in the Brent oil price over the same period.

On behalf of our Board of Directors and the team at Gran Tierra, I want to thank all of our stakeholders for their continued support. We believe that our focused strategy is delivering results on several fronts and that Gran Tierra is well positioned for an exciting year of growth in 2017 and beyond as we efficiently create value in the multi-horizon, proven hydrocarbon producing basins of Colombia.

GARY S. GUIDRY
President and
Chief Executive Officer

(1) Funds flow from operations is a non-GAAP measure and does not have a standardized meaning under GAAP. Refer to "Non-GAAP Measures" in this document for a description of this non-GAAP measure and a reconciliation to the most directly comparable measure calculated and presented in accordance with GAAP.

Our mission is to create value for all of our stakeholders through oil & gas exploration and production, capitalizing on the global operating experience of our team. We are building a record of success in Colombia in a transparent, safe, secure and responsible way.

For more information on how Gran Tierra operates in an environmental and socially responsible way you can read our CSR report at **grantierra.com**

Financial, Operating and Reserves Highlights

	THREE MONTHS ENDED DECEMBER 31,		TWELVE MONTHS ENDED DECEMBER 31,	
	2016	2015	2016	2015
Average Daily Volumes (BOEPD)				
Working Interest Production Before Royalties	31,031	23,138	27,062	23,401
Royalties	(4,768)	(3,397)	(3,875)	(3,912)
Production NAR	26,263	19,741	23,187	19,489
Decrease (Increase) in Inventory	214	(2,707)	767	(1,229)
Sales (1)	26,477	17,034	23,954	18,260
Prices ($/BOE)				
Brent	51.13	43.57	44.33	52.35
Realized Sales Price (2)	31.89	29.07	28.38	34.06
Operating Costs (2)	(8.50)	(7.55)	(8.51)	(9.31)
Transportation Costs (2)	(2.60)	(6.47)	(3.12)	(4.96)
Operating Netback (2), (3)	20.79	15.05	16.75	19.79
Financial Figures ($ thousands)				
Net Cash Provided by Operating Activities	6,643	3,726	93,042	62,305
Net Loss	(127,355)	(82,722)	(465,565)	(268,029)
EBITDA (3)	30,745	15,052	120,095	132,216
Funds Flow from Operations (3)	36,186	16,855	104,984	107,570
Capital Expenditures	58,219	137,856	127,789	156,639

Financial Figures ($ thousands)	AS AT DECEMBER 31, 2016	AS AT DECEMBER 31, 2015
Cash, Cash Equivalents & Current Restricted Cash	33,497	145,434
Working Capital (Deficiency) Surplus, Including Cash & Cash Equivalents	(23,344)	160,449
Revolving Credit Facility	90,000	-
Convertible Senior Notes	115,000	-

Total Company (4)	2016 YEAR-END	2015 YEAR-END	2016 YEAR-END	2015 YEAR-END
BOE (NI 51-101 & COGEH Compliant)	WI RESERVES	WI RESERVES	BEFORE TAX NPV10	BEFORE TAX NPV10
Reserves Category	MBOE	MBOE	$ MILLION	$ MILLION
Total Proved	72,827	48,350	1,230	814
Total Probable	53,313	17,612	925	286
Total Proved plus Probable	126,140	65,962	2,155	1,100
Total Possible	73,103	15,047	1,196	274
Total Proved plus Probable plus Possible	199,243	81,009	3,351	1,374

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

2) Based on W.I. Sales before royalties.

3) Operating netbacks, funds flow from operations and earnings before interest, taxes, depletion, depreciation, accretion and impairment ("DD&A") ("EBITDA") are non-GAAP measures and do not have a standardized meaning under generally accepted accounting principles in the United States of America ("GAAP"). Refer to "Non-GAAP Measures" in this report for descriptions of these non-GAAP measures and reconciliations to the most directly comparable measures calculated and presented in accordance with GAAP.

4) Based on independent reserve reports prepared by McDaniel as of December 31, 2016 & December 31, 2015, in accordance with NI 51-101 & COGEH compliant gross W.I.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2016

or

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

For the transition period from __________ to __________

Commission file number 001-34018

GRAN TIERRA ENERGY INC.

(Exact name of registrant as specified in its charter)

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

900, 520 - 3 Avenue SW
Calgary, Alberta Canada T2P 0R3
(Address of principal executive offices, including zip code)

(403) 265-3221
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.001 per share	**NYSE MKT**
	Toronto Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes ☐ No ☒

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

Indicate by check mark whether the registrant submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☒	Accelerated filer ☐
Non-accelerated filer ☐ (do not check if a smaller reporting company)	Smaller reporting company ☐

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2016, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $1.0 billion.

On February 23, 2017, the following numbers of shares of the registrant's capital stock were outstanding: 390,815,190 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 3,387,302 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 4,804,592 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this report, to the extent not set forth herein, is incorporated by reference from the registrant's definitive proxy statement relating to the 2017 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2016.

Gran Tierra Energy Inc.

Annual Report on Form 10-K

Year Ended December 31, 2016

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K 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 Annual Report on Form 10-K regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words "believe", "expect", "anticipate", "intend", "estimate", "project", "target", "goal", "plan", "objective", "should", or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part I, Item 1A "Risk Factors" in this Annual Report on Form 10-K. The information included herein is given as of the filing date of this Form 10-K 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 Annual Report on Form 10-K 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
BOE	barrels of oil equivalent	bopd	barrels of oil per day
MMBOE	million barrels of oil equivalent	NGL	natural gas liquids
BOEPD	barrels of oil equivalent per day	NAR	net after royalty

Sales volumes represent production NAR adjusted for inventory changes and losses. Our oil and gas reserves are reported NAR. Our production is also reported NAR, except as otherwise specifically noted as "working interest production before royalties." 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.

Below are explanations of some commonly used terms in the oil and gas business and in this report.

Developed acres. The number of acres that are allocated or assignable to producing wells or wells capable of production.

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. Exploratory or development well that does not produce oil or gas in commercial quantities.

Exploitation activities. The process of the recovery of fluids from reservoirs and drilling and development of oil and gas reserves.

Exploration well. An exploration well is a well drilled to find a new field or new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well or a stratigraphic test well.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which we own a working interest.

Net acres or net wells. The sum of the fractional working interests we own in gross acres or gross wells expressed as whole numbers and fractions of whole numbers.

Possible reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. The SEC provides a complete definition of possible reserves in Rule 4-10(a)(17) of Regulation S-X.

Probable reserves. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered. The SEC provides a complete definition of probable reserves in Rule 4-10(a)(18) of Regulation S-X.

Productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Proved developed reserves. In general, reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. The SEC provides a complete definition of developed oil and gas reserves in Rule 4-10(a)(6) of Regulation S-X.

Proved reserves. Those quantities of oil and natural 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 (LKH) 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.

Proved undeveloped reserves. In general, reserves 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. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

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.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas regardless of whether such acreage contains proved reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and a share of production and requires the owner to pay a share of the costs of drilling and production operations.

PART I

Items 1 and 2. *Business and Properties*

General

Gran Tierra Energy Inc. together with its subsidiaries (“Gran Tierra”, "us", "our", or “we”) is an independent international energy company engaged in oil and gas acquisition, exploration, development and production. We are strategically focused on onshore oil and gas properties in Colombia and also own the rights to oil and gas properties in Brazil and Peru. Our Colombian properties represented 87% of our proved reserves NAR at December 31, 2016. The remainder of our proved reserves were attributable to our Brazilian properties. For the year ended December 31, 2016, 97% (year ended December 31, 2015 - 97%; year ended December 31, 2014 - 95%) of our revenue and other income was generated in Colombia.

Our company was incorporated under the laws of the State of Nevada on June 6, 2003, originally under the name Goldstrike Inc. On October 31, 2016, the Company changed its state of incorporation from the State of Nevada to the State of Delaware (the “Reincorporation”) pursuant to a plan of conversion, dated October 31, 2016. The Reincorporation was accomplished by the filing of (i) articles of conversion with the Nevada Secretary of State, and (ii) a certificate of conversion and a certificate of incorporation with the Delaware Secretary of State. Pursuant to the plan of conversion, the Company also adopted new bylaws. The Reincorporation was previously submitted to a vote of, and approved by, the Company’s stockholders at its 2016 Annual Meeting of Stockholders held on June 23, 2016.

We made our initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005. Since then, we have acquired oil and gas producing and non-producing assets in Colombia, Peru, Argentina and Brazil. We sold our Argentina business unit in June 2014. In 2016, we completed acquisitions of Petroamerica Oil Corp. ("Petroamerica"), PetroGranada Colombia Limited ("PGC") and PetroLatina Energy Limited ("PetroLatina").

On February, 6, 2017, we announced that a purchase and sale agreement (the "Agreement") had been executed by a third party ("Purchaser") to purchase our Brazil business unit through the acquisition of all of the equity interests in one of our indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising our Brazil business unit to the Gran Tierra group of companies (the "Brazil Divestiture").

Upon completion of the Brazil Divestiture, the Purchaser will acquire all of our assets and certain liabilities in Brazil, including our 100% working interest in the Tiê Field and all of our interest in exploration rights and obligations held pursuant to concession agreements granted by the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis of Brazil ("ANP").

The completion of the Brazil Divestiture is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP. The consideration to be received on the completion of the Brazil Divestiture is $35 million, subject to adjustments, plus the assumption by the Purchaser of certain existing and potential liabilities of our Brazil business unit. Pursuant to the Agreement, the Purchaser paid a deposit of $3.5 million on February 7, 2017, which is not refundable in the event the Purchaser is not successful in obtaining financing to complete the Brazil Divestiture.

The economic effective date of the transaction will be on or before August 1, 2017, and we will continue to operate our Brazil business unit until the completion of the Brazil Divestiture.

All dollar ($) amounts referred to in this Annual Report on Form 10-K are United States (U.S.) dollars, unless otherwise indicated.

2016 Overview

Acquisitions

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

Additionally, on January 25, 2016, we acquired all of the issued and outstanding common shares of PGC for cash consideration. The net purchase price of PGC was $19.4 million, after giving effect to net working capital of $18.3 million. PGC's working capital on the acquisition date included restricted cash of $18.6 million and cash of $0.2 million. All of the opening balance of restricted cash was released prior to December 31, 2016. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra.

On August 23, 2016, we acquired all of the issued and outstanding common shares of PetroLatina for $525.0 million, consisting of: cash consideration of $465.7 million, which included a deferred cash payment of $25.0 million that was paid on December 31, 2016; assumption of a reserve-backed credit facility with an outstanding balance of $80.0 million; and net of working capital of $17.3 million and other closing adjustments. Upon completion of the transaction, we repaid and canceled the reserve-based credit facility and PetroLatina became an indirect wholly-owned subsidiary of Gran Tierra. The PetroLatina acquisition was funded through a combination of our existing cash balance, gross proceeds of $173.5 million from the subscription receipts offering noted below, available borrowings under our existing revolving credit facility and $130.0 million of borrowings under a bridge loan facility.

On November 25, 2016, we submitted winning bids totaling a combined $30.4 million for two blocks which Ecopetrol S.A. ("Ecopetrol") offered as part of an asset disposition process. Our winning bids were on the Santana and Nancy-Burdine-Maxine Blocks, which are located in the Putumayo Basin. Ecopetrol will transfer ownership of the blocks' assets, contracts, permits and licenses, as well as 100% ownership of Ecopetrol's rights and obligations in respect of the oil and gas assets, to us once the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) grants approval and the conditions of the assignment agreement are met. We intend to finance the $30.4 million purchase price with borrowings under our revolving credit facility.

Debt and equity offerings

During April 2016, we issued $115 million aggregate principal amount of 5.00% Convertible Senior Notes due 2021 (the "Notes") in a private placement to qualified institutional buyers. Net proceeds from the sale of the Notes were $109.1 million, after deducting the initial purchasers' discount and the offering expenses. The Notes bear interest at a rate of 5.00% per year.

On July 8, 2016, we issued approximately 57.8 million subscription receipts ("Subscription Receipts") in a private placement to eligible purchasers at a price of $3.00 per Subscription Receipt for gross proceeds of approximately $173.5 million or net proceeds after share issuance costs of $165.8 million. The proceeds were used to partially fund the PetroLatina acquisition. Each Subscription Receipt entitled the holder to automatically receive one common share of the Company upon closing of the PetroLatina acquisition upon the satisfaction of certain conditions, which occurred on August 23, 2016.

On November 16, 2016, the borrowing base on our revolving credit facility was increased to $250 million readily available. Previously, the borrowing base was $185.0 million, with $160.0 million readily available and $25.0 million subject to the consent of all lenders. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders semi-annually. Our borrowing base will next be re-determined no later than May 2017.

On November 29, 2016, we issued approximately 43.3 million shares of common stock at a public offering price of $3.00 per share, for aggregate gross proceeds of approximately $130.0 million (the "Offering"). The proceeds were used to repay borrowings outstanding under our revolving credit facility.

Colombian peace agreement

On September 26, 2016, the Colombian government and the Revolutionary Armed Forces of Colombia ("FARC") signed a peace agreement (the "Peace Agreement") and, on November 30, 2016, the Peace Agreement was ratified by Colombia's government. Pursuant to the Peace Agreement, the FARC agreed to demobilize its troops and urban militia members and to hand over its weapons to a United Nations mission within 180 days. Once demobilized and disarmed, the FARC can become a legal political party. Under the Peace Agreement, the FARC will be guaranteed at least five seats in the Senate and another five seats in the House of Representatives in 2018 congressional elections.

2016 Operational Highlights

In the year ended December 31, 2016, we incurred capital expenditures of $127.8 million, including $106.0 million or 83% in Colombia, $15.1 million in Brazil, $5.1 million in Peru and $1.6 million in Corporate.

The significant elements of our 2016 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Guriyaco-1 exploration well, which was completed as an oil producer. We completed the Costayaco-24 development well and drilled and completed the Costayaco-23i, Costayaco-27i, Moqueta-20 and Moqueta 22 development wells in the Costayaco and Moqueta Fields. All four wells were completed as oil producers. We performed recompletions on Costayaco-9 and Costayaco-19 and began producing from a new zone in the field, the A-Limestone formation. We also completed a dual completion on the Moqueta-19i water injector well. We drilled the Moqueta-23 development well.

- On the Midas Block (100% WI, operated), we drilled and completed the Acordionero-5 and Acordionero-7 development wells as oil producers and commenced drilling the Acordionero-8i development well.

- On the Putumayo-7 Block (100% WI, operated), we drilled and completed the Cumplidor-1 exploration well, which was completed as an oil producer, and commenced drilling of the Alpha-1 exploration well.

- On the Putumayo-4 Block (100% WI, operated), we continued activities related to environmental permitting for the Siriri-1 exploration well.

- On the Suroriente Block (15.8% WI, non-operated), we commenced a well workover campaign at the Cohembi and Quinde oil fields.

- We completed the acquisition of 2-D seismic on the Sinu-1 (60% WI, operated) and Sinu-3 (51% WI, operated) Blocks.

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

In Brazil:

- We commenced work on a water injection/pressure support project with an initial workover on the 1-GTE-7HPC-BA well to assess potential as a water source well and we continued facility improvements, including the completion of a compressed natural gas project and a flare stack.

In Peru:

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

2017 Outlook

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

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

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

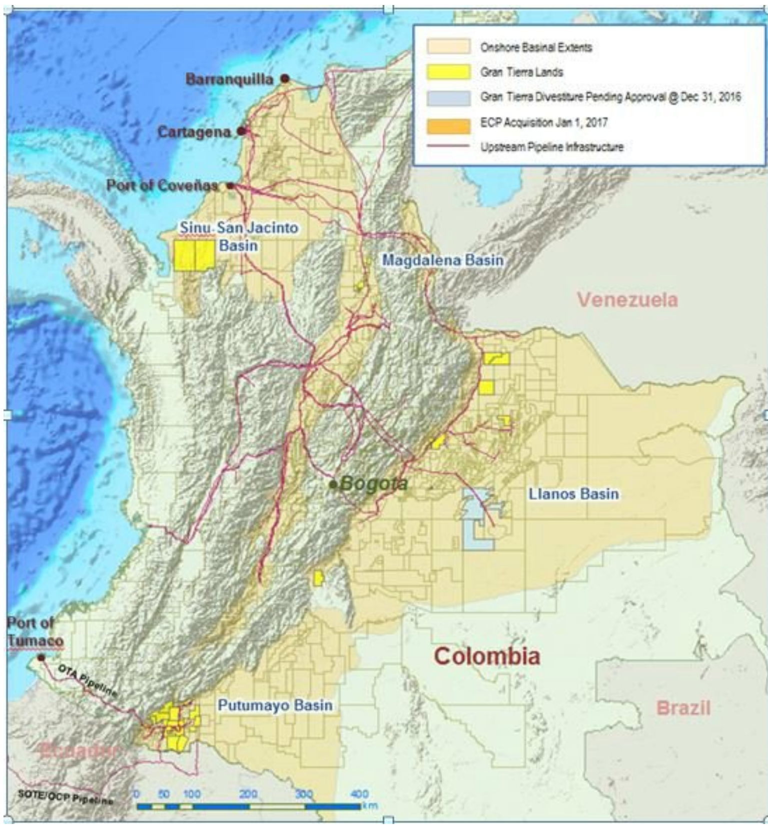
We expect to finance our 2017 capital program through cash flows from operations and available capacity under our credit facility, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions.

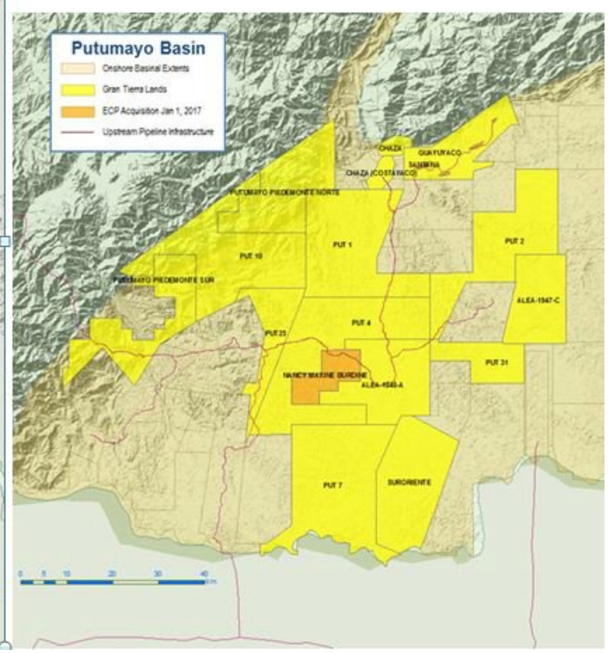
Business Strategy

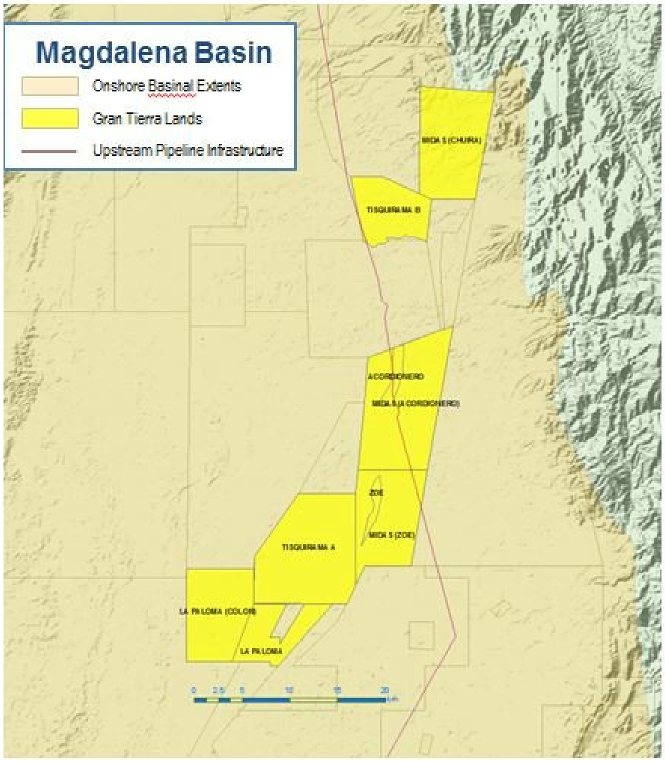
The Company's strategy is to efficiently grow and diversify its portfolio of exploration, development and production opportunities in Colombia. We are taking steps to grow cash flows from existing assets by developing reserves and growing reserves through enhanced oil recovery ("EOR") techniques. Starting in 2017, we have consolidated sufficient exploration opportunities to commence a three to five year continuous exploration program which we expect will be fully funded through the reinvestment of cash flows from operations and leverage of our financial strength.

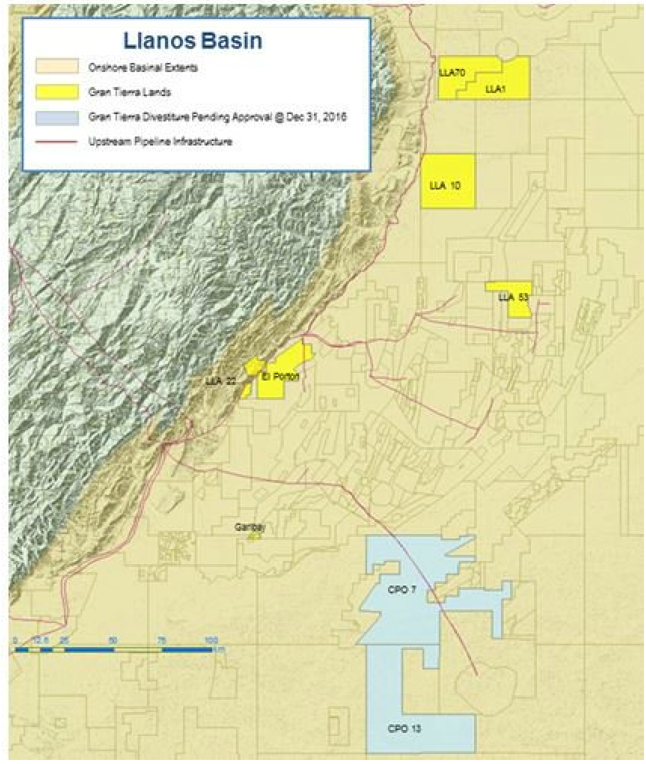
Oil and Gas Properties

Colombian Properties









On January 13, 2016, January 25, 2016, and August 23, 2016, respectively, we completed the acquisitions of all of the issued and outstanding shares of Petroamerica, PGC and PetroLatina, respectively.

On November 25, 2016, we submitted winning bids totaling a combined $30.4 million for two blocks which Ecopetrol S.A. offered as part of an asset disposition process. Our winning bids were on the Santana and Nancy-Burdine-Maxine Blocks, which are located in the Putumayo Basin. Ecopetrol will transfer ownership of the blocks' assets, contracts, permits and licenses, as well as 100% ownership of Ecopetrol's rights and obligations in respect of the oil and gas assets, to us once the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) grants approval and the conditions of the assignment agreement are met. We intend to finance the $30.4 million purchase price with borrowings under our revolving credit facility.

During 2016, we sold our interests in the El Eden and Los Ocarros Blocks to a third party and executed an agreement to transfer our interests in the CPO-7 and CPO-13 Blocks to a third party. Assignment of these WIs is subject to approval, or final approval, by the ANH. We also relinquished our interests in four blocks (Llanos-19, Cauca 6 and 7 and Catguas) and in the Garibay exploration area (we retain our interest in the Melero and Jilguero Fields on the Garibay Block). We requested and received approval to transfer work obligations on these blocks to the Putumayo-4 and Putumayo-7 Blocks. Approval of our request to transfer work obligations on the Catguas Block to the Putumayo-2 is pending. Relinquishments of our interests in ten blocks in Colombia are subject to receipt of final documentation from the ANH (Llanos-19, Cauca-6 and 7, Catguas, Azar, Magdalena, Sierra Nevada, El Balay, Guachiria Norte, Primavera).

Excluding blocks subject to relinquishment and the two blocks awarded in the 2016 Colombia asset disposition process, we have interests in 31 blocks in Colombia and are the operator on 22 of these blocks. The following table provides a summary of selected data for these blocks as at December 31, 2016:

Block and Field (s)	Basin	WI	Estimated Proved Reserves, NAR	2016 Average Production NAR, BOEPD[1]	Number of Productive Wells , Net	End of Production Phase	Acres, Net[2]
Chaza - Costayaco, Moqueta and Guriyaco Fields	Putumayo	100% operated	23,730	16,577	34.0	2033 for Costayaco and 2037 for Moqueta	16,472
Guayuyaco - Guayuyaco and Juanambu Fields	Putumayo	70% operated	1,114	648	3.5	2030	36,656
Suroriente - Cohembi and Quillacinga Fields	Putumayo	15.8%[3] non-operated	392	738	2.7	2024	14,262
Putumayo-7 - Cumplidor Field	Putumayo	100% operated	990	42	1.0	24 years from the date of commerciality	130,186
Midas - Acordionero, Chuira and Zoe Fields	Middle Magdalena	100% operated	17,350	1,845	9.0	2035 for Chuira, 2036 for Zoe and 2039 for Acordionero	45,689
La Paloma - Colon and Juglar Fields	Middle Magdalena	100% operated	429	96	5.0	2034 for Colon and 2039 for Juglar	23,756
Tisquirama A and B - Los Angeles and Querubin Fields	Middle Magdalena	See below	371	73	5.2	Until the economic limit of each field	9,120
Garibay - Jilguero and Melero Fields	Llanos	See below	321	559	1.5	2037	821
Llanos-22 - Ramiriqui Field	Llanos	45% non-operated	1,447	952	0.9	2038	11.258
Other Blocks	See below	See below	—	940	0.8	—	2,005,522
			46,144	**22,470**	**63.6**		**2,293,742**

[1] Includes production on two blocks which were sold during 2016.
[2] Excludes our interest in 13 blocks with a total of 2.8 million net acres for which government approval of relinquishments or sale was pending at December 31, 2016. Includes our interest in the CPO-7 and CPO-13 Blocks which we disposed of subsequent to December 31, 2016. Excludes the Santana and Nancy-Burdine blocks since the acquisition of our interests in those blocks had not closed at December 31, 2016.
[3] Our interest in this block is held through our partially owned subsidiaries.

Status of Exploration Phases

Putumayo Basin Blocks

Chaza Block (100% WI, operated)

The second additional exploration program ended on January 30, 2016. This exploration phase required one exploration well to be drilled, which was satisfied by the Eslabón Sur Deep-1 exploration well. The exploration period in the Chaza Block has ended and we retain the Moqueta and Costayaco Fields.

Guayuyaco Block (70% WI, operated)

We have completed all of our obligations in relation to this contract. Ecopetrol has the option to back-in to a 30% participation interest in any other new discoveries in the block.

Putumayo-4 Block (100% WI, operated)

During 2016, we acquired the remaining 30% WI in this block in the PetroLatina acquisition. We are in the first exploration phase. We requested and received approval to transfer work obligations from the Cauca-7 and Garibay blocks to this block. The transferred work obligation consisted of drilling an exploration well. We requested and were granted an extension of this phase to February 17, 2018. This phase requires the acquisition, processing and interpretation of 143 kilometers of 2-D seismic, and two exploration wells to be drilled. We have satisfied the seismic work obligation on this block.

Putumayo-1 Block (55% WI, operated)

We are in the first of two exploration phases. We requested and were granted a suspension of this phase due to community issues. This phase requires the acquisition of 159 square kilometers of 3-D seismic and one exploration well to be drilled. We have satisfied the seismic work obligation on this block.

Putumayo-10 Block (100% WI, operated)

We are in the first of two exploration phases. We requested and were granted a suspension of the exploration phase due to community and permitting issues. This phase requires the acquisition of 73 kilometers of 2-D seismic and two exploration wells to be drilled. We will have 20 months from the date the suspension is lifted to complete the work obligation.

Putumayo-31 Block (100% WI, operated)

During 2016, we acquired the remaining 35% WI in this block in the Petroamerica acquisition. We are in phase zero, the community consultation phase. We requested and were granted an extension of this phase to March 2, 2017. We have requested a further extension of this phase.

Putumayo Piedemonte Norte Block (70% WI, operated)

We are in the first of six exploration phases, which is currently under suspension. This exploration phase requires the acquisition, processing and interpretation of 70 kilometers of 2-D seismic. We have already acquired 18 kilometers of 2-D seismic on this block.

Putumayo Piedemonte Sur Block (100% WI, operated)

We are in a unified phase two and three of six exploration phases. We requested and were granted a suspension and restitution of this phase for 229 days so that the new phase would end on July 22, 2017. However, our environmental license application was rejected by the Colombian environmental agency due to the high environmental sensitivity in the area (a decision which we have appealed), and therefore, we have requested to keep the phase suspended. This unified phase requires the acquisition of 55 kilometers of 2-D seismic and one exploration well to be drilled. We have satisfied the 2-D seismic work obligation on this block.

Llanos Basin Blocks

Garibay Block (Jilguero Field - Mirador 30.35% WI and 50% other areas; Melero Field 50% WI, non-operated)

During 2016, the ANH approved our request to transfer our work obligation in this block to the Putumayo-4 Block; as a result we do not have any remaining exploration work obligations in this block. The exploration period in the Garibay Block has ended and we retain the Jilguero and Melero Fields.

Llanos-22 Block (45% WI, non-operated)

We are in a unified first and second additional exploration program. Our partner requested and was granted a suspension of the exploration program. Once the suspension is lifted we will have 507 days to complete the work obligation. This exploration program requires one exploration well to be drilled and the acquisition of 85 square kilometers of 3-D seismic.

Sinu Basin Blocks

Sinu-1 Block (60% WI, operated)

The contract comprises one exploration phase which requires the completion of regional studies, the acquisition of 479 kilometers of 2-D seismic and one stratigraphic well to be drilled by August 13, 2017. We completed the regional studies and the acquisition 479 kilometers of 2-D seismic, but are required to acquire an additional 80 kilometers of 2-D seismic to satisfy the minimum required investment.

Sinu-3 Block (51% WI, operated)

We are in the first exploration phase. We requested and were granted an extension of this phase to June 11, 2017. This phase requires the completion of regional studies, the acquisition of 488 kilometers of 2-D seismic and one exploration well to be drilled. We completed the regional studies and the seismic work obligation on this block.

Blocks acquired in the Petroamerica and PGC acquisitions

We acquired interests in the following blocks through the acquisitions of Petroamerica and PGC on January 13, 2016, and January 25, 2016, respectively.

Putumayo Basin Blocks

Putumayo-7 Block (100% WI, operator)

During 2016, we received regulatory approval for the assignment of 100% WI in this block to Petroamerica (50% and Operator) and PGC (50%). This block is in phase one of two exploration phases. We requested and were granted a change of the work obligation from the acquisition of 83.3 square kilometers of 3-D seismic to the drilling of one exploration well. Additionally, we requested and were granted a transfer of work obligations from the Cauca-6 and Llanos-19 blocks to this block, and an extension of the phase for 109 days in order to perform the new work obligations. We also requested and were granted a suspension and restitution of the phase for 69 days. As a result, the phase will end on October 12, 2017. This phase requires the acquisition of 95.3 square kilometers of 3-D seismic and four explorations wells to be drilled. During 2016, we drilled the Cumplidor-1 and Alpha-1 exploration wells which discovered oil, however, we have not yet declared commerciality in this area.

Putumayo-2 Block (100% WI, operator)

We are in the second exploration phase. This phase was suspended, but we requested and were granted the lifting of the suspension. The phase will end on October 16, 2019. We have requested a transfer of the work obligation from the Catguas block to this block. This phase requires two exploration wells to be drilled and the acquisition of 10 square kilometers of 3-D seismic. If the work obligation transfer is approved, the work obligation for this phase will be three exploration wells. The seismic work obligation was satisfied prior to our acquisition of Petroamerica.

Suroriente Block (15.8% WI, non-operated)

We hold our interest in this block through our partially owned subsidiaries. All work obligations in relation to this contract were completed prior to our acquisition of Petroamerica. This is a “Crude Incremental Production Contract” with Ecopetrol. Under the terms of the contract, the working interests are subject to an “R” factor which can reduce the net WI depending on future investment and cash flow ratios. Although the contract is described as an incremental production contract, in this particular case, the working interest parties share in the entire amount of the crude production with Ecopetrol, due to the base production level being set at zero over the life of the contract, which expires in 2024.

Alea 1848-A (50% WI, non-operated)

We are in a unified three and four of five exploration phases. The suspension of this phase was lifted and the phase will end July 5, 2017. This phase requires the reprocessing of 500 kilometers of 2-D seismic, the acquisition of 70 kilometers of 2-D seismic, the acquisition of 52 square kilometers of 3-D seismic and one exploration well to be drilled. The work obligation for the reprocessing of 2-D seismic was satisfied prior to our acquisition of Petroamerica.

Alea 1947-C (49.5% WI, non-operated)

We hold our interest in this block through our partially owned subsidiaries. We are in phase two of five exploration phases. The suspension of this phase was lifted and the phase will end May 19, 2017. This phase requires one exploration well to be drilled.

Llanos Basin Blocks

Llanos-10 (50% WI, non-operated)

We are in the first of two exploration phases, which is currently under suspension. This phase requires the acquisition of 127 square kilometers of 3-D seismic and one exploration well to be drilled. The seismic work obligation was satisfied prior to our acquisition of Petroamerica.

El Porton (100% WI, operator)

Prior to our acquisition of Petroamerica, Petroamerica's two partners on this block withdrew from the exploration phase of the contract and decided not to continue into the fifth exploration phase. As a result, Petroamerica retains 100% WI of the exploration phase of this block. We are in the fifth exploration phase. We requested and were granted an extension of this phase to June 2, 2017. This phase requires one exploration well to be drilled.

Caguán-Putumayo Basin Block

Tinigua (40% WI, operator)

We are in the second of six exploration phases. We requested and were granted a suspension of this exploration phase. Once the suspension is lifted we will have 471 days to complete the work obligation. This phase requires one exploration well to be drilled. The drilling of the exploration well is subjected to a carry from our partner for 90% of the well costs (including testing and completion) up to $12 million.

Lower Magdalena Basin Blocks

Arjona Block (30% WI, non-operated)

This is a contract for the operation of Ecopetrol undeveloped discovered fields. The evaluation period in the Arjona Block has ended. All work obligations in relation to such evaluation period were completed prior to our acquisition of Petroamerica and the contract expiration date is November 9, 2017.

Blocks acquired in the PetroLatina Acquisition

We acquired interests in the following blocks through the acquisition of PetroLatina on August 23, 2016:

Middle Magdalena Basin Blocks

Midas Block (100% WI, operator)

All work obligations in relation to this contract were completed prior to our acquisition of PetroLatina.

La Paloma (100% WI, operator)

All work obligations in relation to this contract were completed prior to our acquisition of PetroLatina.

Tisquirama A and B (Querubin Field - 20% revenue WI and 25% cost WI; Los Angeles Field - 40% revenue WI and 50% cost WI; operator)

All obligations in relation to these contracts were completed prior to our acquisition of PetroLatina.

Putumayo Basin Block

Putumayo-25 Block (100% WI, operator)

We are in phase zero, the community consultation phase, was due to end on November 12, 2016, but we have requested an extension of this phase.

Llanos Basin Blocks

Llanos-1 (100% WI, operated)

We are in phase one of two exploration phases. This phase will end on December 29, 2018, and requires the acquisition of 97.5 square kilometers of 3-D seismic and one exploration well to be drilled.

Llanos-70 (100% WI, operated)

We are in phase one of two exploration phases. This phase will end on December 29, 2018, and requires the acquisition of 163 square kilometers of 3-D seismic and one exploration well to be drilled.

Llanos-53 (100% WI, operated)

We are in phase one of two exploration phases. This phase will end on August 10, 2017, but we have requested a suspension of this phase. This phase requires the acquisition of 89 square kilometers of 3-D seismic and two exploration wells to be drilled.

Royalties

Colombian royalties are regulated under laws 756 of 2002 and 1530 of 2012. All discoveries made subsequent to the enactment of law 756 of 2002 have the sliding scale royalty described below. Discoveries made before the enactment of this law have a royalty of 20%. The ANH contracts to which we are a party all have royalties that are based on a sliding scale described in law 756. This royalty works on an individual oil field basis starting with a base royalty rate of 8% for gross production of less than 5,000 bopd. The royalty increases in a linear fashion from 8% to 20% for gross production between 5,000 and 125,000 bopd and is stable at 20% for gross production between 125,000 and 400,000 bopd. For gross production between 400,000 and 600,000 bopd the rate increases in a linear fashion from 20% to 25%. For gross production in excess of 600,000 bopd the royalty rate is fixed at 25%. In addition to the sliding scale royalty, the following blocks have additional x-factor royalties: Llanos-22, Putumayo-2, Putumayo-4 and Putumayo-7: 1%; Sinu-1 and Llanos-10: 3%; Putumayo-31: 12%; Sinu-3:17%; Llanos-1: 31%; Llanos-53: 33%; Llanos-70: 31% and Putumayo 25: 19%.

For gas fields, the royalty is on an individual gas field basis starting with a base royalty rate of 6.4% for gross production of less than 28.5 MMcf of gas per day. The royalty increases in a linear fashion from 6.4% to 20% for gross production between 28.5 MMcf of gas per day and 3.42 Bcf of gas per day and is stable at 16% for gross production between 712.5 to 2,280 MMcf of gas per day. For gross production between 2.28 to 3.42 Bcf of gas per day the rate increases in a linear fashion from 16% to 20%. For gross production in excess of 3.42 Bcf of gas per day the royalty rate is fixed at 20%.

Pursuant to the Chaza Block exploration and production contract (the "Chaza Contract") between the ANH and Gran Tierra, our production from the Costayaco and Moqueta Exploitation Areas are also subject to an additional royalty (the "HPR royalty") that 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. Pursuant to the Chaza Contract, any new Exploitation Area on the Chaza Block will also be subject to the HPR royalty once the production on such Exploitation Area exceeds five MMbbl of cumulative production. Cumulative gross production from the Acordionero Exploitation Area in the Midas Block exceeded five MMbbl during January 2017, and since that time we have been paying the HPR Royalty on production from the Acordionero Exploitation Area. The Jilguero Exploitation Area in the Garibay Block will be subject to the HPR royalty once production from such Exploitation Area has reached five MMbbl.

For exploration and production contracts awarded in the 2010, 2012 and 2014 Colombia Bid Rounds, the HPR royalty will apply once the production from the area governed by the contract, rather than any particular Exploitation Area designated under the contract, exceeds five MMbbl of cumulative production. We expect that this criterion for the HPR royalty will apply for subsequent bid rounds.

The Guayuyaco and Suroriente Blocks have the sliding scale royalty but do not have the additional royalty.

In addition to these government royalties, our original interests in the Guayuyaco and Chaza Blocks acquired on our entry into Colombia in 2006 are subject to a third party royalty. The additional interests in Guayuyaco and Chaza that we acquired on the acquisition of Solana in 2008 are not subject to this third party royalty. On June 20, 2006, we entered into a participation agreement that would effectively compensate Crosby Capital, LLC ("Crosby") for its share in certain Colombian properties. The compensation is in the form of overriding royalty rights that apply to our original interests in production from the Guayuyaco and Chaza Blocks. The overriding royalty rights start with a 2% rate on working interest production less government royalties. For new commercial fields discovered within 10 years of the agreement date and after a prescribed threshold is reached, Crosby reserves the right to convert the overriding royalty rights to a net profit interest ("NPI"). This NPI ranges from 7.5% to 10% of working interest production less sliding scale government royalties, as described above, and operating and overhead costs. No adjustment is made for the HPR royalty. On certain pre-existing fields, Crosby does not have the right to convert its overriding royalty rights to an NPI. In addition, there are conditional overriding royalty rights that apply only to the pre-existing fields. Currently, we are subject to a 10% NPI on 50% of our working interest production from the Costayaco and Moqueta Fields in the Chaza Block and 35% of our working interest production from the Juanambu Field in the Guayuyaco Block, and overriding royalties on our working interest production from the Guayuyaco Field in the Guayuyaco Block.

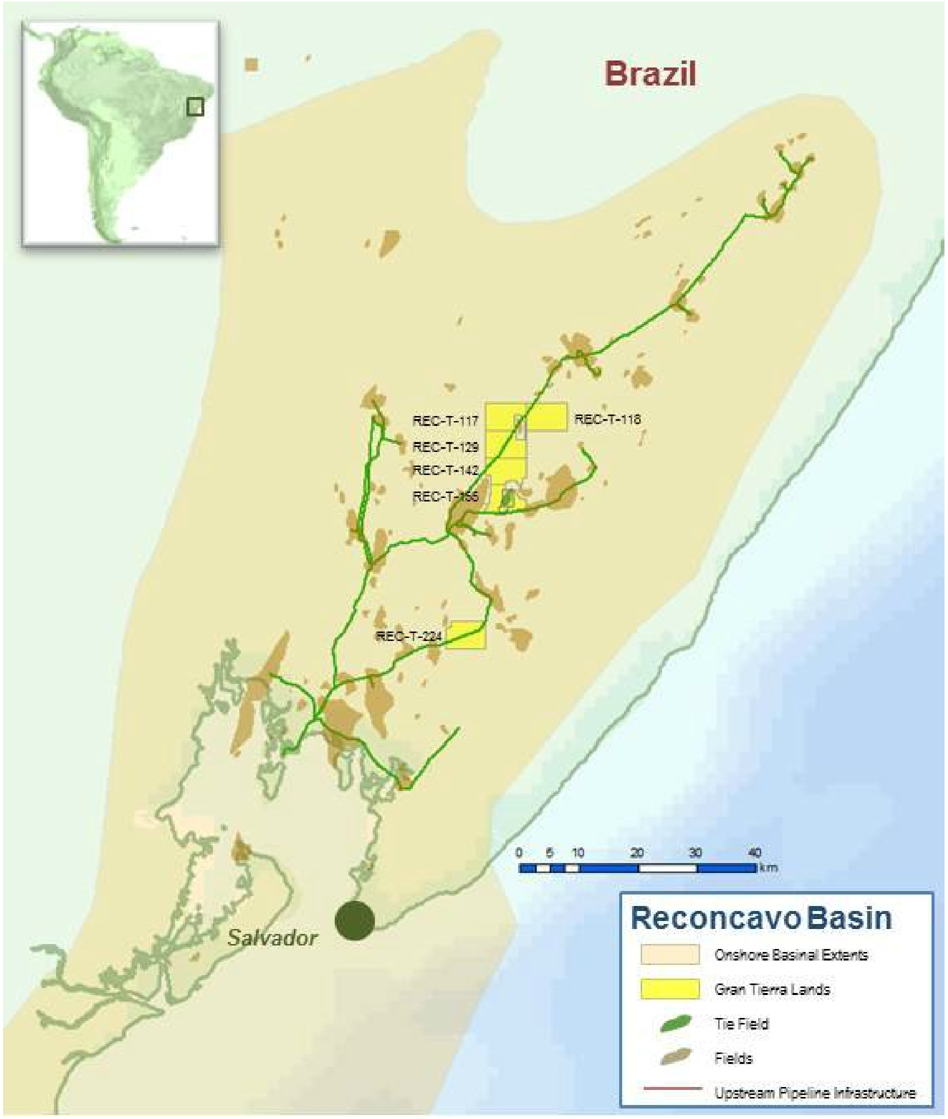
The Putumayo-7 Block is also subject to a third party royalty in addition to the government royalties. Pursuant to the terms of the agreement by which the interests in the Putumayo-7 Block were acquired, a 10% royalty on production from the Putumayo-7 Block is payable to a third party. The terms of the royalty allow for transportation costs, marketing and handling fees, government royalties (including royalties payable to the ANH pursuant to Section 39 of the contract for the Putumayo-7 Block - the "Rights Due to High Prices") and taxes (other than taxes measured by the income of any party, and other than VAT or any equivalent) to be paid in cash or kind to the Government of Colombia (or any federal, state, regional or local government agency) and ANH, and the 1% 'X' factor payment to be deducted from production revenue prior to the royalty being paid to a third party.

Brazilian Properties

On February 6, 2017, we announced that a purchase and sale agreement had been executed by a Purchaser to purchase our Brazil business unit through the acquisition of all of the equity interests in one of our indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising our Brazil business unit to the Gran Tierra group of companies. Upon completion of the Brazil Divestiture, the Purchaser will acquire all of our assets and certain liabilities in Brazil, including our 100% working interest in the Tiê Field and all of our interest in exploration rights and obligations held pursuant to concession agreements granted by the ANP.

The completion of the Brazil Divestiture is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP. The consideration to be received on the completion of the Brazil Divestiture is $35 million, subject to adjustments, plus the assumption by the Purchaser of certain existing and potential liabilities of our Brazil business unit. Pursuant to the Agreement, the Purchaser paid a deposit of $3.5 million on February 7, 2017, which is not refundable in the event the Purchaser is not successful in obtaining financing to complete the Brazil Divestiture.

The economic effective date of the transaction will be on or before August 1, 2017, and we will continue to operate our Brazil business unit until the completion of the Brazil Divestiture.



We have a 100% WI in six blocks in Brazil and are the operator in all of these blocks. Our Brazilian properties are located in the Recôncavo Basin in Eastern Brazil in the State of Bahia. During 2016, we relinquished our interest in Block REC-T-86 at the end of the Block's first exploration phase.

All of our blocks in Brazil are subject to an 11% royalty, which consists of a 10% crown royalty and a 1% landowner royalty.

Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 (100% WI, operated)

Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 are located approximately 70 kilometers northeast of Salvador, Brazil in the Recôncavo Basin and cover 27,076 gross acres. The Tiê Field on Block 155 includes two productive wells.

In 2014, a class action was initiated by the Brazilian Federal Prosecutor to suspend the effects of the 12th Bidding Round of the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") until the issuance of proper environmental regulations. The ANP also issued a resolution to regulate fracture stimulation, which required appropriate environmental permits be in place to specifically authorize fracturing activities in unconventional reservoirs. The result was to halt unconventional activities on the Bid Round 12 blocks, which were promoted as unconventional exploration blocks, until such a time as policies governing unconventional activities could be coordinated and finalized among State and Federal environmental agencies. 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 class action; however, the ANP's resolution and the regulatory uncertainty has limited our ability to receive permits for drilling unconventional exploration targets on our blocks.

The First Appraisal Plan ("PAD") phase for Blocks REC-T-129, REC-T-142 and REC-T-155 ended on May 24, 2015, however we requested and were granted a suspension of the PAD phase until regulatory policies governing unconventional activities are finalized.

The exploration phase of the concession agreement on Block REC-T-224 was due to expire on December 11, 2013; however, we requested and were granted a suspension and extension of the exploration phase of this block. Block REC-T-224 is currently in force majeure pending the approval of environmental permits. The exploration phase on Block REC-T-224 will end one year after the date an environmental permit is granted. This phase requires one exploration well to be drilled.

Blocks REC-T-117 and REC-T-118 (100% WI, operated)

Blocks REC-T-117 and REC-T-118 are located north of our other blocks in the Recôncavo Basin and cover 14,530 gross acres. Both blocks are in the first exploration phase which was due to end in August 2016, but for which we requested and were granted an extension to August 2017 to allow reinterpretation of seismic data to allow definition on conventional prospects. This phase required the acquisition of a total of 58.5 square kilometers of 3-D seismic and two exploration wells to be drilled on Block REC-T-117 and three exploration wells on Block REC-T-118. We have satisfied the work obligation for the acquisition, processing and interpretation of 3-D seismic. We have requested a rephasing of the work obligations for the exploration commitments on Blocks 117 and 118 that would move the obligations to 2017.

Peruvian Properties

We have a 100% WI in five blocks in Peru and we are the operator in all of these blocks. The following table provides summary information for our blocks in Peru:

Block	Acres, Gross and Net
Block 95	853,210
Block 123	2,323,831
Block 129	1,167,409
Block 107	623,504
Block 133	764,320
	5,732,274

All blocks in Peru are subject to a license agreement with PeruPetro. There is a 5-20% sliding scale royalty rate on the lands, dependent on production levels. Production less than 5,000 bopd is assessed a royalty of 5%. For production between 5,000 and 100,000 bopd there is a linear sliding scale between 5% and 20%. Production over 100,000 bopd has a flat royalty of 20%. This royalty structure applies to all blocks in Peru in which we have an interest. Block 133 has an additional royalty 'X' factor of 15%.

Status of Exploration Phases

Block 95 (100% WI, operated)

In February 2015, we ceased all further development expenditures in the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security. We requested and were granted a three year retention period from December 28, 2015, to ring-fence the Bretaña Structure. The obligation during this retention period is to evaluate the economics of the project in order to decide whether to declare commerciality by December 27, 2018.

We successfully "ring-fenced" Block 95's Bretaña Field with PeruPetro S.A., and maintain the remainder of Block 95 as exploration acreage for an additional two years until December 2017. This additional exploration period requires the completion of 176 units of work to move to the next phase or forfeiture with no penalty or commitment.

Block 123 and Block 129 (100% WI, operated)

Both blocks are in the third exploration period of five and are under force majeure. On Block 123, the current exploration period required one exploration well to be drilled or the completion of 300 units of work. This work obligation was satisfied by the acquisition of 318 kilometers of 2-D seismic prior to assuming operatorship. On Block 129, the current exploration period required one exploration well to be drilled or the completion of 204 units of work. This work obligation was satisfied by the acquisition of 252 kilometers of 2-D seismic by our former partners on this block.

Block 107 (100% WI, operated)

We are in the fifth and final exploration period, which is suspended due to delays in the permitting process. A 3-year extension of the fifth exploration phase was granted on April 30 2015. This period requires two exploration wells to be drilled. During 2016, we completed the information required for the EIA approval process. Upon approval of the EIA and necessary permits, suspension of the period will end and the 3-year period will commence.

Block 133 (100% WI, operated)

We are in the third exploration period of four, which is in force majeure pending the approval of 2-D seismic and drilling EIAs. This period requires one exploration well to be drilled or the completion of 200 units of work. Upon approval of the EIA and necessary permits, suspension of the period will end and we would have 24 months to complete the work obligation.

Administrative Facilities

Our principal executive offices are located in Calgary, Alberta, Canada. The Calgary office lease will expire on November 29, 2022. We also have office space in Colombia, Peru and Brazil.

Estimated Reserves

Our 2016 reserves were independently prepared by McDaniel International Inc. ("McDaniel"), a wholly owned subsidiary of McDaniel & Associates. McDaniel & Associates was established in 1955 as an independent Canadian consulting firm and has been providing oil and gas reserves evaluation services to the world's petroleum industry for the past 60 years. They have internationally recognized expertise in reserves evaluations, resource assessments, geological studies, and acquisition and disposition advisory services. McDaniel has offices in Calgary, Canada and Guildford, United Kingdom. The technical person primarily responsible for the preparation of our reserves estimates at McDaniel meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The primary internal technical person in charge of overseeing the preparation of our reserve estimates is the Vice President, Asset Management. He has a B. Eng (Hons) degree in mechanical engineering and is a professional engineer and member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He is responsible for our engineering activities including reserves reporting, asset evaluation, reservoir management and field development. He has over 20 years of experience working internationally in the oil and gas industry.

We have developed internal controls for estimating and evaluating reserves. Our internal controls over reserve estimates include: 100% of our reserves are evaluated by an independent reservoir engineering firm, at least annually; and review controls are followed, including an independent internal review of assumptions used in the reserve estimates and presentation of the results of this internal review to our reserves committee. Calculations and data are reviewed at several levels of the organization to ensure consistent and appropriate standards and procedures. Our policies are applied by all staff involved in generating and reporting reserve estimates including geological, engineering and finance personnel.

The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. “Risk Factors”. The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. Therefore, the accuracy of the reserve estimate is dependent on the quality of the data, the accuracy of the assumptions based on the data and the interpretations and judgment related to the data.

Proved reserves are reserves 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 under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Estimates of proved reserves are generated through the integration of relevant geological, engineering, and production data, utilizing technologies that have been demonstrated in the field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate. Probable reserves are 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. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us.

Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

The following table sets forth our estimated reserves NAR as of December 31, 2016.

Reserves Category	Oil (Mbbl)	Natural Gas (MMcf)	Oil and Natural Gas (MBOE)
Proved			
Developed			
Colombia	35,529	1,468	35,774
Brazil	1,912	1,382	2,142
Total proved developed reserves	37,441	2,850	37,916
Undeveloped			
Colombia	10,349	127	10,370
Brazil	4,140	2,203	4,506
Total proved undeveloped reserves	14,489	2,330	14,876
Total proved reserves	51,930	5,180	52,792
Probable			
Developed			
Colombia	10,852	190	10,884
Total probable developed reserves	10,852	190	10,884
Undeveloped			
Colombia	31,132	2,193	31,498
Brazil	1,649	962	1,809
Total probable undeveloped reserves	32,781	3,155	33,307
Total probable reserves	43,633	3,345	44,191
Possible			
Developed			
Colombia	12,613	504	12,697
Total possible developed reserves	12,613	504	12,697
Undeveloped			
Colombia	46,935	1,411	47,170
Brazil	3,407	2,009	3,742
Total possible undeveloped reserves	50,342	3,420	50,912
Total possible reserves	62,955	3,924	63,609

Product Prices Used In Reserves Estimates

The product prices that were used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions and/or distance from market. The average realized prices for reserves in the report are:

Oil and NGLs (USD/bbl) - Colombia	$ 31.67
Natural Gas (USD/Mcf) - Colombia	$ 3.67
Light/Medium Oil (USD/bbl) - Brazil	$ 31.42
Natural Gas (USD/Mcf) - Brazil	$ 1.47

Proved Undeveloped Reserves

At December 31, 2016, we had total proved undeveloped reserves NAR of 14.9 MMBOE (December 31, 2015 - 7.6 MMBOE), including 10.4 MMBOE in Colombia (December 31, 2015 – 5.0 MMBOE) and 4.5 MMBOE in Brazil (December 31, 2015 – 2.6 MMBOE). Approximately 64%, 5% and 1% of proved undeveloped reserves, respectively, are located in our Acordionero, Costayaco and Ramiriqui Fields in Colombia, and 30% are in the Tiê Field in Brazil. None of our proved undeveloped reserves at December 31, 2016, have remained undeveloped for five years or more since initial disclosure as proved reserves and we have adopted a development plan which indicates that the proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure as proved reserves.

Material changes in proved undeveloped reserves are summarized in the table below:

		Oil Equivalent (MMBOE)
Balance, December 31, 2015	**$**	**7.6**
Acquisitions		**9.5**
Converted to proved producing		**(4.5)**
Technical revisions		**1.5**
Discoveries and extensions		**0.8**
Balance, December 31, 2016	**$**	**14.9**

In 2016, we converted 4.5 MMBOE, or 59% of year-end 2015 proved undeveloped reserves, to developed status. In 2016, we made investments, consisting solely of capital expenditures, of $10.1 million in Colombia and $4.0 million in Brazil, associated with the development of proved undeveloped reserves.

During 2016, as part of the PetroLatina acquisition, we acquired the Acordionero Field in Colombia which added 9.5 MMBOE of proved undeveloped reserves ("PUDs"). PUD conversions into proved developed producing reserves occurred primarily on the Chaza Block in Colombia due to the drilling of three production locations and one conversion to injection in the Moqueta Field, and injection well drilling in the Costayaco Field. Additionally, the discovery of the A-Limestone reservoir and increase in injection capacity in these properties resulted in a net increase in proved developed producing reserves. Also, PUDs were added in the existing waterflood zones in the Costayaco Field based on modeling work. In Brazil, no new wells were drilled; however, positive technical revisions of PUDs occurred in Tiê Field. The ALV-2 well was converted to injection in 2016 and injection is scheduled to start in March 2017. PUDs in the Tiê Field consist of an attic producer and an additional well conversion to injection.

Production, Revenue and Price History

Certain information concerning production, prices, revenues and operating expenses for the three years ended December 31, 2016, is set forth in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and in the Unaudited Supplementary Data provided following our Financial Statements in Item 8, which information is incorporated by reference here.

The following table presents oil and NGL production NAR from our Costayaco, Moqueta and Acordionero Fields for the three years ended December 31, 2016:

	Year Ended December 31,						
	2016			2015		2014	
	Costayaco	Moqueta	Acordionero	Costayaco	Moqueta	Costayaco	Moqueta
Oil and NGL's, bbl	**3,975,842**	**2,091,361**	**648,518**	4,053,977	2,005,444	4,194,933	1,690,335
Average sales price of oil and NGL's per bbl	**$ 33.52**	**$ 32.86**	**$ 35.87**	$ 42.57	$ 42.10	$ 83.05	$ 82.84
Operating expenses of oil and NGL's per bbl	**$ 13.71**	**$ 10.50**	**$ 8.00**	$ 14.87	$ 15.93	$ 15.50	$ 12.06

We prepared the estimate of standardized measure of proved reserves in accordance with the Financial Accounting Standards Board (“FASB”) Accounting Standards Codification 932, “Extractive Activities – Oil and Gas”.

Drilling Activities

The following table summarizes the results of our exploration and development drilling activity for the past three years. Wells labeled as “In Progress” for a year were in progress as of December 31, 2016, 2015 or 2014. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to Gran Tierra of productive wells compared to the costs of dry holes.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	**2.00**	**2.00**	—	—	—	—
Dry	—	—	1.00	1.00	2.00	2.00
In Progress	**1.00**	**1.00**	—	—	1.00	1.00
Development						
Productive	**7.00**	**7.00**	7.00	5.16	6.00	6.00
Service	**2.00**	**2.00**	—	—	—	—
Dry	**1.00**	**1.00**	—		—	—
In Progress	**3.00**	**3.00**	6.00	6.00	3.00	3.00
Total Colombia	**16.00**	**16.00**	14.00	12.16	12.00	12.00
Brazil						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	2.00	2.00
In Progress	—	—	—	—	—	—
Development						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Total Brazil	—	—	—	—	2.00	2.00
Peru						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Development						
Productive	—	—	—	—	—	—
Service	—	—	1.00	1.00	—	—
Dry	—	—	1.00	1.00	—	—
In Progress	—	—	—	—	1.00	1.00
Total Peru	—	—	2.00	2.00	1.00	1.00
Total	**16.00**	**16.00**	16.00	14.16	15.00	15.00

Of the six wells in progress in Colombia as at December 31, 2015, two were producing, two were service wells, one continued to be in progress (suspended), and one was dry at December 31, 2016.

In 2016, we also continued pressure maintenance projects in the Costayaco and Moqueta Fields in Colombia.

Well Statistics

The following table sets forth our productive wells as of December 31, 2016:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia[1]	96.0	63.63	—	—	96.0	63.6
Brazil[2]	2.0	2.0	—	—	2.0	2.0
Peru	—	—	—	—	—	—
	98.0	65.6	—	—	98.0	65.6

(1) Includes 14.0 gross and 11.7 net water injector wells and 51.0 gross and 49.5 net wells with multiple completions.
(2) Includes 2.0 gross and net wells with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2016:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia[1]	274,592	150,225	3,787,827	2,143,517	4,062,419	2,293,742
Brazil	1,511	1,511	40,095	40,095	41,606	41,606
Peru	—	—	5,732,274	5,732,274	5,732,274	5,732,274
Gran Tierra as at December 31, 2016[1]	276,103	151,736	9,560,196	7,915,886	9,836,299	8,067,622

(1) Excludes our interest in 13 blocks in Colombia with a total of 2.8 million net acres for which government approval of relinquishments or sale was pending at December 31, 2016. Excludes the Santana and Nancy-Burdine blocks since the acquisition of our interests in those blocks had not closed at December 31, 2016.

At December 31, 2016, our gross undeveloped acreage was located 60% in Peru (36% Blocks 123 and 129) and 40% in Colombia.

Research and Development

We utilize existing technology, industry best practices and continual process improvement to execute our business plan. We have not expended any resources on pursuing research and development initiatives.

Marketing and Major Customers

Colombia

Our oil in Colombia is mainly located in the Middle Magdalena Valley ("MMV") and Putumayo Basin. In MMV, our focus is on the Acordionero field, where production is approximately 18° API and represented 8% of our production in 2016. The Putumayo production (as defined below) is approximately 29° API and represented 80% of our production in 2016.

We have entered into numerous agreements to sell oil produced in the Chaza and Guayuyaco Blocks (the "Putumayo production"). These agreements are subject to renegotiation annually and generally contain mutual termination provisions with 30 days' notice. The volume of crude oil does not include the volume of oil corresponding to royalties taken in kind, but does include volumes relating to HPR royalties.

We may, but are not obligated to, sell up to 100% of our Putumayo production to Ecopetrol. The Ecopetrol agreement will expire March 31, 2017. We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and through the transportation and logistics assets of CENIT Transporte y Logistica de Hidrocarburos S.A.S ("CENIT"), a wholly-owned subsidiary of Ecopetrol. The point of sale of our Putumayo production to Ecopetrol is the Port of Tumaco on the Pacific coast of Colombia.

We have entered into ship and pay transportation agreements (the "Transportation Agreements") with CENIT. These agreements will expire November 30, 2017. Pursuant to the Transportation Agreements we pay a transportation tariff and transportation tax for the transportation of the Putumayo production from the Putumayo Basin to the Port of Tumaco. Pursuant to the Transportation Agreements, each of Gran Tierra Energy Colombia Ltd. and Petrolifera Petroleum (Colombia) Limited have the right to transport up to 10,000 bopd, subject to availability of capacity, of crude oil production from the Chaza and Guayuyaco Blocks in Colombia: (1) from Santana Station to CENIT's facility at Orito through CENIT's Mansoya – Orito Pipeline, and (2) from CENIT's facility at Orito to the Port of Tumaco through CENIT's Orito – Tumaco Pipeline. We can request that CENIT transport additional crude oil in excess of 20,000 bopd through the pipelines on the same terms, which CENIT may do at its sole discretion. Generally, under these agreements, CENIT is liable (subject to specified limitations) for pollution clean up costs resulting from incidents during transportation. The cost of oil lost during transportation is shared by the parties that ship oil on the pipeline, in proportion to their share of total volumes shipped.

Currently we have Firm Capacity Transportation Agreements for 6,000 bopd, of which 3,000 bopd are under ship or pay agreements and 3,000 bopd are under ship and pay agreements. These agreements will expire October 31, 2020. The remainder of our Putumayo production is transported through the Transportation Agreements.

Putumayo production is also sold to multiple other parties, in addition to Ecopetrol. Other sales in Putumayo are generally delivered at the wellhead. Oil can be delivered and sold at the Costayaco battery and loaded into trucks or sold via pipeline. When oil is oil is loaded into trucks there are multiple evacuation routes. When oil is delivered to facilities at Babillas Station, the sales point is the Port of Coveñas upon oil export, or delivered via pipeline to the Port of Esmeraldas, Ecuador and the sales point is when oil is loaded into an export tanker.

Varying amounts of oil are trucked: (1) from Santana Station to Ecopetrol's storage terminal at Orito, a distance of approximately 47 kilometers; (2) from the Costayaco Field to Ecopetrol's storage terminal at Babillas, approximately 363 kilometers north of the Chaza Block; (3) from the Costayaco Field to Hocol´s unloading facilities at Neiva (Babillas Station), approximately 361 kilometers north of the Chaza Block; (4) from the Costayaco Field to the Atlántico Oil Terminal in Barranquilla, a distance of approximately 1,534 kilometers; (5) from the Garibay Jilguero Field to facilities at Cusiana Station, a distance of approximately 75 kilometers; and; (6) from the Llanos 22 Ramiriqui Field to facilities at Cusiana Station, a distance of approximately 35 kilometers.

In MMV, the Acordionero field has a firm volumetric contract which will end by approximately the first quarter of 2018. Presently, we truck these volume 530 kilometers to the buyer at Puerto Bahia, Cartagena Bay. We are evaluating pipeline tie at the Acordionero field which will give access to the Port of Coveñas for future sales at the export terminal.

Production from the minor fields in MMV is sold at the wellhead on a short-term contract which will expire June 30, 2017.

We receive revenues for our Colombian oil sales in U.S. dollars. Oil prices for sales of our crude oil are defined by agreements with the purchasers of the oil and are based generally on an average price for crude oil, using Brent, with adjustments such as for quality, specified fees, transportation fees and transportation tax.

Brazil

Petróleo Brasileiro S.A ("Petrobras") is the main purchaser of our oil production from Block 155 in Brazil. Oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. Oil prices for sales to Petrobras are based on the monthly average Dated Brent price less a refining and quality discount.

Competition

The oil and gas industry is highly competitive. We face competition from both local and international companies in acquiring properties, contracting for drilling and other oil field equipment and securing trained personnel. Many of these competitors, such as Ecopetrol, have greater financial and technical resources. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for prospects and resources in the oil and natural gas industry.

Geographic Information

Information regarding our geographic segments, including information on revenues, assets, expenses and net income, can be found in Note 5 to the Consolidated Financial Statements, Segment and Geographic Reporting, in Item 8 "Financial Statements and Supplementary Data", which information is incorporated by reference here. Long lived assets are Property, Plant and

Equipment, which includes all oil and gas assets, furniture and fixtures, automobiles and computer equipment. No long lived assets are held in our country of domicile, which is the United States of America. "All Other" assets include assets held by our corporate head office in Calgary, Alberta, Canada. Because all of our exploration and development operations are in South America, we face many risks associated with these operations. See Item 1A “Risk Factors” for risks associated with our foreign operations.

Regulation

The oil and gas industry in Colombia, Peru and Brazil is heavily regulated. Rights and obligations with regard to exploration, development and production activities are explicit for each project; economics are governed by a royalty/tax regime. Various government approvals are required for property acquisitions and transfers, including, but not limited to, meeting financial and technical qualification criteria in order to be certified as an oil and gas company in the country. Oil and gas concessions are typically granted for fixed terms with opportunity for extension.

Colombia

In Colombia, prior to 2004, Ecopetrol was the administrator of all hydrocarbons and therefore executed contracts with oil companies under different contractual types such as Association Contracts and Shared Risk Contracts. Under an Association Contract, the oil company (“Associate”) assumed all risk during the exploration phase and Ecopetrol had the obligation to reimburse the Associate, if the commerciality was accepted by Ecopetrol, the direct exploration costs which the Associate incurred in proportion to Ecopetrol's working interest. If Ecopetrol did not accept the initial commerciality of a field, the Associate could continue the activities at its sole risk and Ecopetrol would retain the right to back-in later, after Ecopetrol reimbursed the Associate for the initial exploitation work and exploration costs plus certain penalties, depending upon at what stage Ecopetrol later declared commerciality of the field.

Effective June 2003, the regulatory regime in Colombia underwent a significant change with the formation of the ANH. The ANH is now the administrator of the hydrocarbons in the country and therefore is responsible for regulating the Colombian oil and gas industry, including managing all exploration lands. Ecopetrol became a public company owned in majority by the state with the main purpose of exploring and producing hydrocarbons similar to any other oil company. However, Ecopetrol continues to have rights under the existing contracts executed with oil companies before the ANH was created. Ecopetrol continues to be the major purchaser and marketer of oil in Colombia and operates the majority of the oil transportation infrastructure in the country.

In conjunction with this change, the ANH developed a new exploration risk contract that took effect as of June 2004. This Exploration and Production Contract has significantly changed the way the industry views Colombia. In place of the earlier association contracts, the new agreement provides full risk/reward benefits for the contractor. Under the terms of the contract the successful operator retains the rights to all reserves, production and income from any new exploration block, subject to existing royalty and tax regulations. Each contract contains an exploration phase and a production phase. The exploration phase will contain a number of exploration periods and each period will have an associated work commitment. The production phase will last a number of years (usually 24) from the declaration of a commercial hydrocarbon discovery.

We operate in Colombia through Colombian branches of the following entities: Gran Tierra Energy Colombia Ltd., Gran Tierra Colombia Inc. and Petrolifera Petroleum (Colombia) Limited. On December 27, 2016, we completed the merger of four of our Colombian branches: Gran Tierra International Colombia Corp. Sucursal, Gran Tierra Colombia Inc. Sucursal, Gran Tierra P&G Corp Sucursal, and Gran Tierra Energy Corp. Sucursal. Gran Tierra Energy Colombia Ltd. and Gran Tierra Colombia Inc., are currently qualified as operators of oil and gas properties by the ANH.

When operating under a contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, except for royalty volumes which are collected by the ANH (or its designee), depending on the type of contract. The contractor can market the hydrocarbons in any manner whatsoever, subject to a limitation in the case of natural emergencies where the law specifies the manner of sale.

Peru

Peru’s hydrocarbon legislation, which includes the Organic Hydrocarbon Law No. 26221 enacted in 1993 and the regulations thereunder (the “Organic Hydrocarbon Law”), governs our operations in Peru. This legislation covers the entire range of petroleum operations, defines the roles of Peruvian government agencies which regulate and interact with the oil and gas industry, provides that private investors (either national or foreign) may also make investments in the petroleum sector and provides for the promotion of the development of hydrocarbon activities based on free competition and free access to all economic activities. This law provides that pipeline transportation and natural gas distribution must be handled via concession contracts with the appropriate governmental authorities. All other petroleum activities are to be freely operated subject to complying with applicable regulation, including local safety and environment standards.

Under the Peruvian legal system, Peru is the owner of the hydrocarbons located below the surface in its national territory. However, Peru has given the ownership right to extracted hydrocarbons to PeruPetro S.A. ("PeruPetro"), a state company responsible for promoting and overseeing the investment of hydrocarbon exploration and exploitation activities in Peru. PeruPetro is empowered to enter into contracts for either the exploration and exploitation or just the exploitation of petroleum and natural gas on behalf of Peru, the nature of which are described further below. The Peruvian government also plays an active role in petroleum operations through various entities and agencies, including through the involvement of the Ministry of Energy and Mines(the specialized government department in charge of establishing energy, mining and environmental protection policies, enacting the rules applicable to all these sectors and supervising compliance with such policies and rules),OSINERGMIN (an agency in charge of checking compliance with hydrocarbon regulations) and OEFA (the entity of supervising environmental compliance). We are subject to the laws and regulations of all of these entities and agencies.

The Peruvian Constitution and the Organic Hydrocarbon Law states that a license contract does not provide for a transfer or lease of property over the area of the exploration or exploitation. In accordance with a license contract, a third party acquires the right to explore for or exploit hydrocarbons in a specified area and PeruPetro (the entity that holds the Peruvian state interest) transfers the property right in the extracted hydrocarbons to the third party, who must pay a royalty to the state.

PeruPetro enters into either license contracts or service contracts for hydrocarbon exploration and exploitation. Peruvian law also allows for other contract models, but the investor must propose contract terms compatible with Peru’s interests. We only operate under license contracts and do not foresee operating under any service contracts. License and service contracts are approved by supreme decree issued by the Peruvian Ministry of Economy and Finance and the Peruvian Ministry of Energy and Mining, and can only be modified by written agreement signed by the parties. A company must be qualified by PeruPetro to enter into negotiations for hydrocarbon exploration and exploitation contracts in Peru. In order to qualify, the company must meet the standards under the Regulations Governing the Qualifications of Oil Companies. These qualifications generally require the company to have the technical, legal, economic and financial capacity to comply with all obligations it will assume under the contract based on the characteristics of the area requested, the possible investments and the environmental protection rules governing the performance of its operations. When a contractor is a foreign investor, it is required to incorporate a subsidiary company or registered branch in accordance with Peruvian corporate law and appoint Peruvian representatives in accordance with the Organic Hydrocarbon Law who will interact with PeruPetro.

We operate in Peru through Gran Tierra Energy Peru S.R.L. and Petrolifera Petroleum del Peru S.R.L. Gran Tierra Energy Peru S.R.L. has been qualified by PeruPetro with respect to its contracts for Blocks 95, 123 and 129 and Petrolifera has been qualified by PeruPetro with respect to its contracts for Blocks 107 and 133.

When operating under a license contract, the licensee is the owner of the hydrocarbons extracted from the contract area during the performance of operations and pays royalties which are collected by PeruPetro. The licensee can market or export the hydrocarbons in any manner whatsoever, subject to a limitation in the case of national emergency where the law stipulates such manner.

Brazil

In Brazil, Law No. 2,004 enacted in 1953 created the state monopoly of the petroleum industry and Petrobras, a state-owned legal entity, which was the sole company conducting exploration and production activities in Brazil. The Brazilian Federal Constitution enacted on October 5, 1988, continued this state monopoly of the petroleum industry.

Amendment No. 9 to the Brazilian Constitution, enacted on November 9, 1995, relaxed the state monopoly and authorized the Brazilian government to contract, through Concession Contracts, with state and private companies, with head offices and management located in Brazil, for the exploration and production of oil and natural gas, as well as to grant authorizations for the refining, transportation, import and export of oil, natural gas and its by-products.

The regulatory model is governed by Law No. 9,478 of August 6, 1997 (the “Petroleum Law”), as amended, which controls the granting of concessions for carrying out exploration and production activities to Brazilian companies. The Petroleum Law, as amended, also established a legal framework for pre-salt layer areas and strategic areas to be defined by the Brazilian government and which will be subject to the Production Sharing Contracts regime.

In accordance with the Petroleum Law, the acquisition of oil and natural gas property and oil and gas operations by state and private companies is subject to legal, technical and economic standards and regulations issued by the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP"), the agency created by the Petroleum Law and vested with regulatory and inspection authority to ensure adequate operational procedures with respect to industry activities and the supply of fuels throughout the national territory.

The ANP has authority for the implementation of the national oil and natural gas policy in accordance with the National Council of Energy Policy. The ANP conducts bid rounds to award exploration, development and production contracts, as well as to authorize the construction and operation of refineries and gas processing units, transportation facilities (including port terminals), import and export of oil and natural gas, as well as supervision of the activities which integrate the petroleum industry and the general enforcement of the Petroleum Law.

During a public bid procedure, any company evidencing technical, financial and legal standards under the applicable bidding requirements may qualify and apply for particular blocks made available for Concession Contracts. Qualified companies may compete alone or in association with other companies, including through the formation of "consortia" (unincorporated joint-ventures). Blocks awarded and the duration of the exploration and production periods are defined in the contracts which, besides the usual covenants that can be found in oil concessions, such as exploration and development programs, relinquishment of areas, and unitization, include reversion to the state of certain assets at the end of the concession. Contracts may be assigned or transferred to other Brazilian companies that comply with the technical, financial and legal requirements established by the ANP.

Oil and natural gas resources in Brazil, whether onshore or offshore, belong to the Brazilian government. However, under the Concession Contracts regime, after the discovery of oil and gas reserves, ownership is assigned to the concessionaire. Under the principles of the Federal Constitution, the national territory comprises all land and the continental shelf. Brazil is a signatory of the conventions regulating the economic use of the sea and its subsoil. Brazil is thus entitled to the enjoyment of the resources over the territorial sea and marine platform up to the limits indicated in the pertinent treaties.

Concessionaires are required under Law No. 9,478/97 to pay the government dues and fees, in addition to the charges for sale of pre-bid data and information. The ANP has the power to determine the criteria under which the Government Take will be assessed within the limits established by Federal Decree No. 2,705/98. Government Take comprises (i) signature bonus, (ii) royalties, (iii) special participation and (iv) area rentals. Part of the Government Take is passed on to States and Municipalities and other government branches according to law.

We operate in Brazil through Gran Tierra Energy Brasil Ltda. ("Gran Tierra Brazil"). Gran Tierra Brazil received approval from the ANP as a Class B operator permitting Grant Tierra Brazil to act as an operator both onshore and in the shallow water offshore Brazil.

Environmental Compliance

Our activities are subject to laws and regulations governing environmental quality and pollution control in the countries where we maintain operations. Our activities with respect to exploration, drilling, production and facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil and other products, are subject to stringent environmental regulation by regional and federal authorities in Colombia, Peru and Brazil. Such regulations relate to environmental impact studies, the discharge of pollutants into air and water, water use and management, the management of non-hazardous and hazardous waste, including its transportation, storage, and disposal, permitting for the construction of facilities, recycling requirements and reclamation standards, and the protection of certain plants and animal species as well as cultural resources and areas inhabited by indigenous peoples, among others. Risks are inherent in oil and gas exploration, development and production operations. These risks include blowouts, fires, or spills. Significant costs and liabilities may be incurred in connection with environmental compliance issues. Licenses and permits required for our exploration and production activities may not be obtainable on reasonable terms or on a timely basis, which could result in delays and have an adverse effect on our operations. Spills and releases into the environment of petroleum products can result in remediation costs and liability for damages. Moreover, violations of environmental laws and regulations can result in the issuance of administrative, civil, or criminal fines and penalties, as well as orders or injunctions prohibiting some or all of our operations in affected areas. In addition, indigenous groups or other local organizations could oppose our operations in their communities, potentially resulting in delays which could adversely affect our operations.

We do not expect that the cost of compliance with regional and federal provisions, which have been enacted regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment or natural resources, will be material to us.

We have implemented a company wide web-based reporting system which allows us to track incidents and respective corrective actions and associated costs. We have a Corporate Health, Safety, and Environmental Management System as well as a Corporate Environmental Management Plan (EMP). The EMP is based on the environmental performance standards of the World Bank/IFC and reflects best industry practices. We have also implemented an environmental risk management program in place as well as waste management procedures. Air and water testing occur regularly and environmental contingency plans have been prepared for all sites and ground transportation of oil. We have a regular quarterly comprehensive reporting system, reporting to executive management as well as a committee of the Board. We have a schedule of internal audits and routine checking of practices and procedures. Emergency response exercises were conducted in Colombia and Brazil.

Employees

At December 31, 2016, we had 387 full-time employees (December 31, 2015 - 301): 74 located in the Calgary corporate office, 265 in Colombia (183 staff in Bogota and 82 field personnel, of which one was unionized), 26 in Peru (24 office staff in Lima and 2 field staff) and 22 in Brazil (11 office staff in Rio de Janeiro and Salvador and 11 field staff). Other than as disclosed above, none of our employees are represented by labor unions and we consider our employee relations to be good.

Available Information

We make available free of charge through our website at www.grantierra.com our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed or furnished with the Securities and Exchange Commission (“SEC”). Our website address is provided solely for informational purposes. Information on our website is not incorporated into this Annual Report or otherwise made part of this Annual Report.

In addition, the SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements and other information regarding us. Any materials we have filed with the SEC may be read or copied at the SEC’s Public Reference Room at 100 F Street N.E. Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330.

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

Risks Related to Our Business

Guerrilla Activity in Colombia Has Disrupted and Delayed, and Could Continue to Disrupt or Delay, Our Operations and We May Be Unable to Safeguard Our Operations and Personnel in Colombia.

For over 40 years, the Colombian government has been engaged in a conflict with two main Marxist guerrilla groups: the FARC and the 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 was organized to combat FARC and ELN, but has since been dissolved by the Columbian government.

On September 26, 2016, the Colombian government and the Revolutionary Armed Forces of Colombia ("FARC") signed a peace agreement (the "Peace Agreement") and, on November 30, 2016, the Peace Agreement was ratified by Colombia's government. Pursuant to the Peace Agreement, the FARC agreed to demobilize its troops and urban militia members and to hand over its weapons to a United Nations mission within 180 days. Once demobilized and disarmed, the FARC can become a legal political party. Under the Peace Agreement, the FARC will be guaranteed at least five seats in the Senate and another five seats in the House of Representatives in 2018 congressional elections, even if they don’t get enough votes for those seats. Continuing attempts by the Colombian government to reduce or prevent activity of guerrilla dissidents may not be successful and such activity may continue to disrupt our operations in the future.

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Llanos, Sinu-San Jacinto, Middle Magdalena and Lower Magdalena Basins. Pipelines have been primary targets of guerrilla activity, because of the length of such pipelines and the remoteness of the areas in which the pipelines are laid. The OTA pipeline, which transports oil from the Putumayo region to the Port of Tumaco and which is one of our export routes, has been targeted by FARC in the past, however, none of the OTA pipeline disruptions in 2016 were due to incidents by FARC. During 2016, the OTA pipeline was shut down for 89 days primarily due to a natural disaster, a landslide. Such disruptions could harm our business.

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.

We Are Vulnerable to Risks Associated with Geographically Concentrated Operations.

Our producing properties are geographically concentrated in Colombia, and as at December 31, 2016, 87% of our proved reserves were located in Colombia. As a result of this concentration, we may be disproportionately exposed to the impact of, among other things, regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation or guerrilla activities, transportation constraints or market limitations.

If we do Not Have the Resources to Execute on Our Business Plan, We May Be Required to Curtail Our Operations.

Our capital program for 2017 is $200 to $250 million to fund our exploration and development. We expect to finance our 2017 capital program through cash flows from operations and available capacity under our credit facility, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions. 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 between 2014 and 2016 and have remained at low levels in the first part of 2017. 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 operations. If cash flows from operations are not sufficient to fund our capital program, we may choose to delay our business plans which would cause us to reduce our exploration and development activities, 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.

We may ship our oil in Colombia through the OTA pipeline owned by CENIT 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 and Ecopetrol over the operation of the port of Tumaco, which limits our ability to negotiate proposed 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 this 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. CENIT and Ecopetrol maintain responsibility for clean-up of any spilled oil and for pipeline repair.

If these pipelines remain down for extended periods of time, our storage facilities may become full, which may cause us to limit producing activities. 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.

Significant percentages of our production are transported by alternative means. These alternatives can be more expensive and reduce our average realized prices. In addition, these alternative means of transportation may not be sustainable long term. 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.

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

In the event that our cash flow from existing operations and cash on hand is not sufficient, we may require additional capital to fund our planned activities or to expand our exploration and development programs. We may be unable to obtain additional capital on favorable terms, or at all.

If we require additional capital, we may 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 able to access capital on favorable terms or at all. 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.

The Borrowing Base Under Our Revolving Credit Facility May Be Reduced Which Could Hinder or Prevent us From Meeting Our Future Capital Needs.

The borrowing base under our revolving credit facility is currently $250 million, and the maximum amount under our revolving credit facility is $500 million. Our borrowing base is redetermined by the lenders twice per year, and will be re-determined no later than May 2017. Our borrowing base may decrease as a result of oil and natural gas price levels, a decline in oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to current or further declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital market to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Our Business is Subject to Local Legal, Political and Economic Factors Which Are Beyond Our Control, Which Could Impair or Delay 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 years ended December 31, 2014, 2015 and 2016. We do not know how long any such labor action may 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 and protection 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.

In 2015, 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 threatened, and in some cases used, 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.

Environmental regulation related to fracture stimulation drilling has been under review by national agencies for the past couple of years. In 2014, a class action was initiated by the Brazilian Federal Prosecutor to suspend the effects of the 12th Bidding Round of the Agência Nacional de Petróleo Gás Natural e Biocombustíveis ("ANP") until the issuance of proper environmental regulations. The ANP also issued a resolution to regulate fracture stimulation, which required appropriate environmental permits be in place to specifically authorize fracturing activities in unconventional reservoirs. The result was to halt unconventional activities on the Bid Round 12 blocks, which were promoted as unconventional exploration blocks, until such a time as policies governing unconventional activities could be coordinated and finalized among State and Federal environmental agencies. 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 class action; however, the ANP's resolution and the regulatory uncertainty has limited our ability to receive permits for drilling unconventional exploration targets on our blocks. We acquired Blocks REC-T-117 and REC-T-118 in Bid Round 11 and these blocks are also affected by the same regulatory uncertainty with respect to unconventional activities that is affecting blocks acquired in Bid Round 12. Until this situation is resolved, the expansion of our drilling operations in Brazil with respect to unconventional reservoirs has been limited, which could harm our business in Brazil.

Pending regulations related to emissions and the impact of any changes in climate could adversely impact our business.

Governments around the world have become increasingly focused on regulating greenhouse gas ("GHG") emissions and addressing the impacts of climate change in some manner. Brazil, Peru and Colombia all have enacted legislation related to GHG emissions. For example, in July 2015, Colombia announced that it will seek to reduce the national emission of greenhouse gases by at least 20% over the next 15 years. Colombia has also passed legislation requiring the country to generate 77% of its energy from renewable resources and reduce deforestation in the Amazon to zero by 2020. In addition, Colombia has established the National Energy Efficiency Program, which calls for electric utilities, oil and gas companies, and other energy service companies to develop Energy Efficiency Plans to meet goals set forth by the Ministry and the Mining and Energy Planning Unit. Peru and Brazil have passed similar climate change-related measures.

GHG emissions legislation is emerging and is subject to change. For example, on an international level, almost 200 nations agreed in December 2015, to an international climate change agreement in Paris, France (the "Paris Agreement"), that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets. Brazil, Colombia, and Peru have all signed the Paris Agreement. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that we produce.

Current GHG emissions legislation has not resulted in material compliance costs, however, it is not possible at this time to predict whether proposed legislation or regulations will be adopted, and any such future laws and regulations could result in additional compliance costs or additional operating restrictions. If we are unable to recover a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse impact on our business, financial condition and results of operations. In addition, significant restrictions on GHG emissions could result in decreased demand for the oil that we produce, with a resulting decrease in the value of our reserves. Further, to the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of or access to capital. Finally, some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that could have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other extreme climatic events; if such effects were to occur, they could have an adverse effect on our operations.

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 Taxes.

At December 31, 2016, 93% 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 13 to the Consolidated Financial Statements in Part II, Item 8 below, 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 $45.9 million as at December 31, 2016.

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. Maintaining good community relationships is an essential aspect of operating in the oil and gas industry. Communities have demonstrated an ability and willingness to halt operations or delay approvals.

To enjoy the support and trust of local populations and governments, we must demonstrate a commitment to: providing local employment, training and business opportunities; a high level of environmental performance; open and transparent communication; a willingness to discuss and address community issues including community development investments that are carefully selected, not unduly costly and bring lasting social and economic benefits to the community and the area. Improper management of these 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.

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.

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.

The Acquisitions of PetroLatina, Petroamerica and PGC May Not Generate the Results Expected and Could be Difficult to Integrate.

In January 2016, we acquired all of the issued and outstanding shares of Petroamerica and PGC and in August 2016, we acquired all of the issued and outstanding shares of PetroLatina. There can be no assurance that these acquisitions will generate the expected returns and other projected results we anticipate.

Foreign Currency Exchange Rate Volatility 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. Between January 1, 2014 and February 23, 2017, exchange rates between the Colombian peso and U.S. dollar have varied between 1,846 pesos to one U.S. dollar to 3,960 pesos to one U.S. dollar, a fluctuation of approximately 115%. Production in Brazil is invoiced and paid in Brazilian Reals. Between January 1, 2014 and February 23, 2017, the exchange rate of the Brazilian Real has varied between 2.19 Reals to one U.S. dollar to 4.20 Reals to the U.S. dollar, a variance of 92%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the Colombian peso strengthened by 5% against the U.S. dollar in the year ended December 31, 2016, 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 2016 the Colombian government approved tax legislation which consolidated the corporate income tax and CREE tax into a single income tax at 40% for 2017 (including a surtax of 6%), 37% for 2018 (including a surtax of 4%) and 33% for 2019 and onwards. This legislation also introduced a new 5% dividend tax on distributions of previously taxed earnings from 2017 and onwards.

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, including Blocks 107 and 133, and activities in the areas surrounding the block are to be considered with caution due to the eradication of illegal farms by the government.

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 or Canadian Governments 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"), the Canadian Corruption of Foreign Public Officials Act and similar anti-bribery laws in other jurisdictions prohibit corporations and individuals, including us, our subsidiaries and affiliates, partners, and our employees, contractors, and agents working on behalf, from making improper payments to government 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 agents, and partners 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 or unauthorized payment. 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 and Brazil, have strengthened their anti-corruption legislation and enforcement. 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, and expose us to investigation and enforcement outside of the U.S.

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. We cannot guarantee that measures taken to defend against cybersecurity threats 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.

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.

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. 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.

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. Spot prices for West Texas Intermediate ("WTI") declined from approximately $106 per bbl in June 2014 to less than $30 per bbl in January 2016. The spot price for Brent oil declined from approximately $115 per bbl in June 2014 to less than $30 per bbl in January 2016.

Given the current economic environment and unstable conditions in the Middle East, North Africa, China, 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. 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 between 2014 and 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.

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.

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.

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 used or 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 likely to 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. The application of environmental laws to our business may force us to curtail our production as a result of restrictions imposed by government regulators, or increase the costs of our production, development or exploration activities because of increased compliance costs.

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 what we believe to be 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. Our 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.

Risks Related to Our Common Stock

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
- additions and departures of key personnel.
- updated reserve estimates by independent parties.

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.

Item 1B. ***Unresolved Staff Comments***

None.

Item 3. ***Legal Proceedings***

As discussed above (see “Royalties”, above, in Item 1), 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 had interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas.

On June 6, 2016, the Company received a positive decision from the Chamber of Commerce of Bogotá Center for Arbitration and Conciliation tribunal (the "Tribunal") relating to its dispute with the ANH with respect to whether all production from the Moqueta Exploitation Area of the Chaza Block exploration and production contract ("Chaza Contract") was subject to an additional royalty (the "HPR Royalty"). In its decision, the Tribunal found that the HPR Royalty under the Chaza Contract was only payable when the accumulated oil production from the Moqueta Exploitation Area exceeded five MMbbl. That production threshold was reached on April 30, 2015, and since that time the Company has been paying the HPR Royalty on production from the Moqueta Exploitation Area.

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 $45.9 million as at December 31, 2016. 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 4. ***Mine Safety Disclosures***

Not applicable.

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 23, 2017.

Name	Age	Position
Gary S. Guidry	61	President and Chief Executive Officer, Director
Ryan Ellson	41	Chief Financial Officer
James Evans	51	Vice President, Corporate Services
David Hardy	62	Vice President, Legal and General Counsel
Alan Johnson	45	Vice President, Asset Management
Lawrence West	60	Vice President, Exploration
Ed Caldwell	67	Vice President, Health, Safety and Environment & Corporate Social Responsibility
Susan Mawdsley	50	Vice President, Finance and Corporate Controller
Glen Mah	60	Vice President, Business Development
Rodger Trimble	55	Vice President, Investor Relations
Adrian Coral	43	President, Gran Tierra Energy Colombia

Gary Guidry, Chief Executive Officer and President. Mr. Guidry has been Gran Tierra's Chief Executive Officer and President since May 7, 2015. Mr. Guidry was the Chief Executive Officer of Onza Energy Inc. from January 2014, until May 2015. From July 2011 to July 2014, Mr. Guidry served as President and Chief Executive Officer of Caracal Energy Inc. Mr. Guidry also served as President and CEO of Orion Oil & Gas Corp. from October 2009 to July 2011, Tanganyika Oil Corp. from May 2005 to January 2009, and Calpine Natural Gas Trust from October 2003 to February 2005. As chief executive officer of these companies, Mr. Guidry was responsible for overseeing all aspects of the respective company's business. Mr. Guidry currently sits on the boards of Africa Oil Corp. (since April 2008) and Shamaran Petroleum Corp. (since February 2007), where he also serves as a member of each company's Audit Committee. From September 2010 to October 2011, Mr. Guidry also served on the Board of Zodiac Exploration Corp., and from October 2009 to March 2014, he served on the board of TransGlobe Energy Corp. Prior to these positions, Mr. Guidry served as Senior Vice President and subsequently President of Alberta Energy Company International, and President and General Manager of Canadian Occidental Petroleum's Nigerian operations. Mr. Guidry has directed exploration and production operations in Yemen, Syria and Egypt and has worked for oil and gas companies around the world in the U.S., Colombia, Ecuador, Venezuela, Argentina and Oman. Mr. Guidry is an Alberta-registered professional engineer (P. Eng.) and holds a B.Sc. in petroleum engineering from Texas A&M University.

Ryan Ellson, Chief Financial Officer. Mr. Ellson has been Gran Tierra's Chief Financial Officer since May 2015. Mr. Ellson has 15 years of experience in a broad range of international corporate finance and accounting roles. Mr. Ellson was CFO of Onza Energy Inc. from January 2015 to May 2015. From July 2014 until December 2014 Mr. Ellson was Head of Finance for Glencore E&P (Canada) and prior thereto Vice President, Finance at Caracal Energy, a London Stock Exchange listed company with operations in Chad, Africa from August 2011 until July 2014. Prior to Caracal, Mr. Ellson was Vice President of Finance at Sea Dragon Energy from April 2010 until August 2011. In these positions, Mr. Ellson oversaw financial and accounting functions, implemented and oversaw internal financial controls, secured a reserve based lending facility and was involved in multiple capital raises. Mr. Ellson has held management and executive positions with companies operating in Chad, Egypt, India and Canada. Mr. Ellson is a Chartered Accountant and holds a Bachelor of Commerce and a Master of Professional Accounting from the University of Saskatchewan.

James Evans, Vice President, Corporate Services. Mr. Evans has been Gran Tierra's Vice President, Corporate Services, since May 2015. Mr. Evans has over 20 years of experience including working the last 10 years in the international oil and gas industry. Most recently, Mr. Evans was the Head of Compliance & Corporate Services for Glencore E&P (Canada) from July 2014 to December 2014, and prior thereto Vice President of Compliance & Corporate Services at Caracal Energy from July 2011 to June 2014, in each case where he oversaw the execution of corporate strategy and goals, developed and implemented a robust corporate compliance program, and managed all aspects of IT, document control, security and administration. Mr. Evans also managed the recruitment, training and retention of staff in both Calgary and Chad. He oversaw the growth of Caracal Energy from seven employees to in excess of 400 as Caracal Energy exceeded 20,000 barrels of oil per day at the time of sale to Glencore. Prior to Caracal, Mr. Evans held senior management and executive positions at Orion Oil and Gas and Tanganyika Oil, with operating experience in Egypt, Syria and Canada. Mr. Evans is a Certified General Accountant and holds a Bachelor of Commerce degree from the University of Calgary.

David Hardy, Vice President, Legal and General Counsel. Mr. Hardy joined Gran Tierra as General Counsel, Vice President Legal and Secretary on March 1, 2010. He has more than 25 years' experience in the legal profession. Before joining Gran Tierra, he worked for Encana Corporation and for Encana Corporation's predecessor, Pan Canadian, from 2000 through 2009 where he held various positions, including: Vice President Divisional Legal Services, Integrated Oil and Canadian Plains

Divisions; Vice President Regulatory Services, Corporate Relations Division; and Associate General Counsel, Offshore and International Division. For four of his eight years in the Offshore and International Division of Encana, Mr. Hardy led the Legal and Commercial Negotiations Group, where he was responsible for providing strategic legal, commercial and negotiation advice and support to the offshore and international business units. This included dealing with new venture activities and operational, joint venture and host government issues relating to projects in various countries, including Australia, Brazil, Chad, Libya, Oman, Qatar and Yemen. Prior to joining Encana, Mr. Hardy spent over 10 years in private practice and was a partner in a law firm in Calgary, Alberta. He holds a Juris Doctor Degree from the University of Calgary (converted from an LL.B Degree in 2011) and is a member of the Law Society of Alberta and the Association of International Petroleum Negotiators.

Alan Johnson, Vice President, Asset Management. Mr. Johnson has been Gran Tierra's Vice President, Asset Management, since May 2015. Mr. Johnson is a professional engineer with more than 20 years experience working internationally in the oil and gas industry. His experience includes varied technical, managerial and executive roles in drilling, production, reservoir, reserves, corporate planning and asset management. Most recently Mr. Johnson was Head of Asset Management for Glencore E&P (Canada) from April 2014 to April 2015, where he was responsible for all development activities in Chad and prior thereto Director of Asset Management at Caracal Energy from August 2011 to March 2014, where he was responsible for development activities in the Doba basin in Chad, Africa. Mr. Johnson was instrumental in developing oil and gas assets in remote areas of southern Chad, achieving first production in less than 18 months. Mr. Johnson started his E&P career with Shell International in the Dutch North Sea. He then held positions of increasing responsibility with Shell Canada, APF Energy, Rockyview Energy, Delphi Energy and BG Australia. Mr. Johnson graduated with a 1st Class B. Eng (Hons) from Heriot Watt University in Scotland. Mr. Johnson is a Chartered Engineer in the UK and a Professional Engineer in Alberta.

Lawrence West. Vice President, Exploration. Mr. West has been Gran Tierra's Vice President, Exploration, since May 2015. Mr. West has thirty-five years of experience as an executive, explorationist, and geologist. Most recently, Mr. West was Vice President, Exploration at Caracal Energy from July 2011 to June 2014. Mr. West built a multi-disciplinary team to assess resources and grow reserves in the interior rift basins within Chad and led a successful exploration program. During his tenure he successfully executed two large 2D/3D seismic shoots in remote frontier basins, on time and on budget. Prior to Caracal he has been involved in starting and growing several public and private companies, including Reserve Royalty Corp., Chariot Energy, Auriga Energy and Orion Oil and Gas. Lawrence worked at Alberta Energy Company (AEC), where he was on the team that merged with Conwest. He built and led the AEC East team to the Rocky Mountain USA basins. His career began with Imperial Oil working on prospect and reservoir characterization, in multi-disciplinary teams, and as a technical mentor to exploration teams. Lawrence has an Honours Bachelor of Science in Geology from McMaster University and an MBA, specializing in economics, from the University of Calgary.

Ed Caldwell, Vice President, Health, Safety and Environment & Corporate Social Responsibility. Mr. Caldwell has been Gran Tierra's Vice President, Health, Safety and Environment & Corporate Social Responsibility, since June 2016. Mr. Caldwell had a distinguished 27-year career with ExxonMobil and Imperial Oil, and most recently worked with Caracal Energy Inc. in Caracal's efforts and achievement in Chad. Mr. Caldwell has extensive experience in senior Regulatory Approvals and HSE Management roles in Canada, Asia, Russia, and Africa. He has also worked with the Government of Canada and, in that capacity, represented Canada at the OECD Energy/Environment Committee as well as at the Intergovernmental Panel on Climate Change. Mr. Caldwell graduated in Chemical Engineering (Distinction) from Dalhousie University.

Susan Mawdsley, Vice President, Finance and Corporate Controller. Ms. Mawdsley has been Gran Tierra's Vice President, Finance, since June 2016, and has Gran Tierra's Corporate Controller since 2012. She is a Chartered Accountant with 25 years of experience in the oil and gas industry. She has direct responsibility for the finance departments in all business units, as well as treasury and internal audit. Prior to joining Gran Tierra in 2011, she was an independent consultant providing contract controller, CFO, and other finance related services to publicly traded domestic and international oil and gas companies. Ms. Mawdsley is a Chartered Accountant and holds a Bachelor of Music in Performance degree from the University of Toronto.

Glen Mah, Vice President, Business Development. Mr. Mah has been Gran Tierra's Vice President, Business Development since June 2016. He is a Petroleum Geologist with extensive management experience covering the execution of exploration programs, field development and asset management for conventional and unconventional hydrocarbons. He has worked with onshore and offshore projects in various petroleum basins in the Americas, Africa, Middle East and Asia. Mr. Mah was the Chief Geologist with the highly successful Tanganyika Oil Company Ltd. Mr. Mah has Alberta-registered Professional designation with APEGA and holds a Bachelor of Science degree Specialization in Geology from the University of Alberta.

Rodger Trimble, Vice President, Investor Relations. Mr. Trimble has been Gran Tierra's Vice President, Investor Relations since June 2016. He is a Professional Engineer with more than 30 years of experience in domestic and international basins in various management positions. Prior to joining Gran Tierra, Mr. Trimble was Head of Corporate Planning, Budgeting & Finance with Glencore E&P Canada Inc. and prior thereto Director Corporate Planning, Budget & Business Development with Caracal

Energy Inc. (acquired by Glencore E&P). He has held several senior management positions ranging from Country Manager in Argentina with Canadian Hunter Exploration, Vice President, Exploitation with Esprit Energy Trust, Manager, Reservoir Engineering with Apache Canada Inc. and Manager, Upstream Evaluations - Frontiers & International with Husky Energy. Mr. Trimble is an Alberta-registered Professional Engineer and a member of APEGA. He received a Bachelor of Science in Petroleum Engineering (with Distinction) from Stanford University.

Adrian Coral, President, Gran Tierra Energy Colombia. Mr. Coral joined Gran Tierra in August 2006 as an operations engineer in Gran Tierra Energy Colombia, Ltd., and served in that capacity until February 2007. Mr. Coral rejoined Gran Tierra in August 2008 as Operations Director of Gran Tierra Energy Colombia, Ltd. He served in that capacity until September 2011, when he was promoted to Production Manager of Gran Tierra Energy Colombia, Ltd. Mr. Coral was promoted to Senior Operations Manager of Gran Tierra Energy Colombia, Ltd. in April 2013. On August 1, 2014, Mr. Coral was promoted to President, Gran Tierra Energy Colombia. Mr. Coral has a total of 18 years of experience as an engineer or manager in the oil and gas industry. Mr. Coral graduated from the Universidad de América – Bogotá D.C. with a degree as a Petroleum Engineer and from the School of Business Management – Bogotá D.C with degree in Project Management.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Shares of our Common Stock trade on the NYSE MKT and on the Toronto Stock Exchange ("TSX") under the symbol “GTE”. In addition, the exchangeable shares in one of our subsidiaries, Gran Tierra Exchangeco, are listed on the TSX and are trading under the symbol “GTX”.

As of February 23, 2017, there were approximately: 48 holders of record of shares of our Common Stock and 390,815,190 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately three holders of record of 3,387,302 exchangeable shares which may be exchanged on a 1-for-1 basis into shares of our Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing sixteen holders of record of 4,804,592 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into shares of our Common Stock.

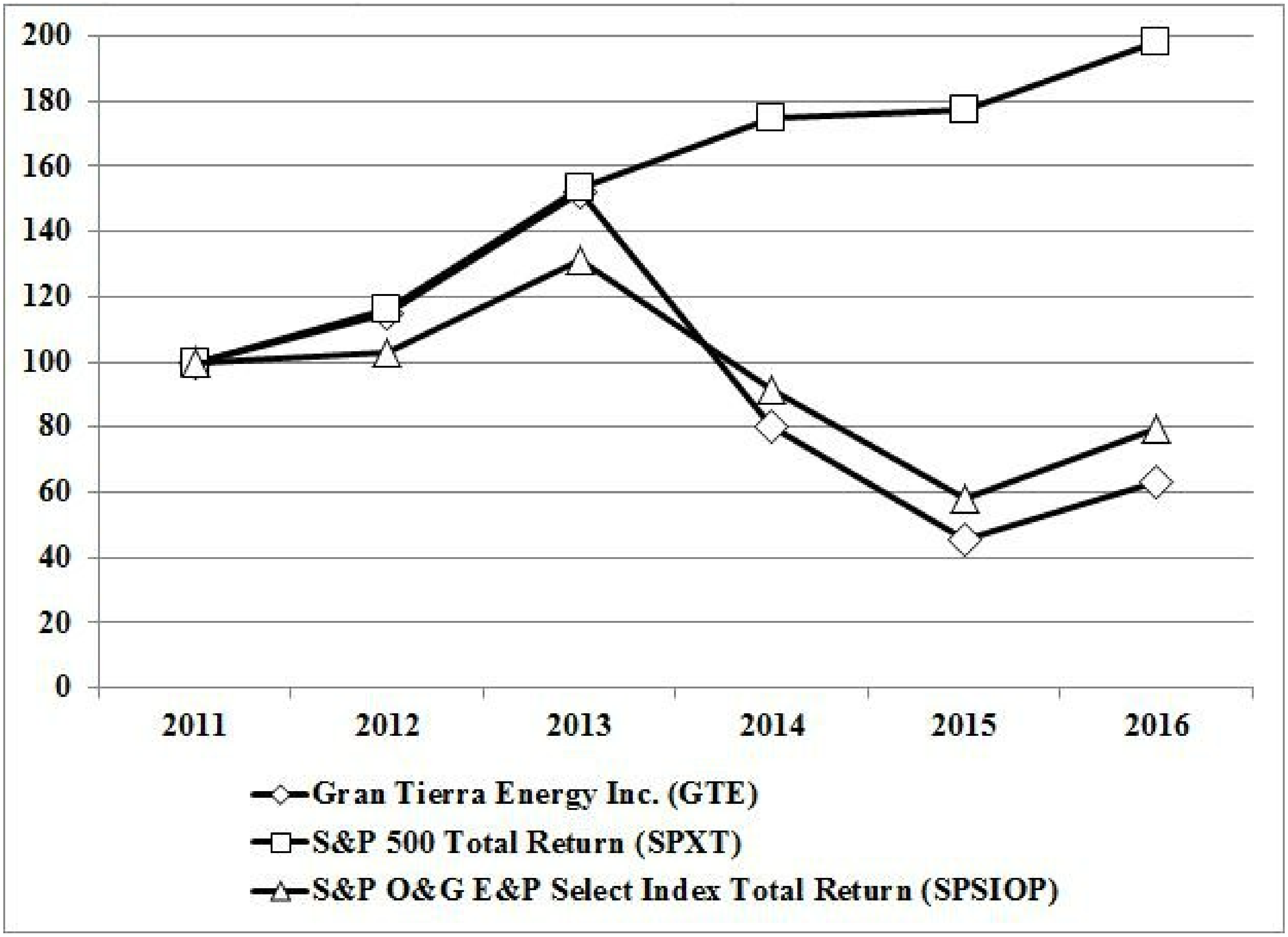
For the quarters indicated from January 1, 2015, through the end of the fourth quarter of 2016, the following table shows the high and low closing sale prices per share of our Common Stock as reported on the NYSE MKT.

	High	Low
Fourth Quarter 2016	$ 3.23	$ 2.60
Third Quarter 2016	$ 3.14	$ 2.65
Second Quarter 2016	$ 3.48	$ 2.31
First Quarter 2016	$ 2.84	$ 1.87
Fourth Quarter 2015	$ 2.91	$ 2.01
Third Quarter 2015	$ 2.92	$ 1.91
Second Quarter 2015	$ 3.87	$ 2.72
First Quarter 2015	$ 3.93	$ 2.10

Dividend Policy

We have never declared or paid dividends on the shares of Common Stock and we intend to retain future earnings, if any, to support the development of the business and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, would be at the discretion of our Board of Directors after taking into account various factors, including current financial condition, the tax impact of repatriating cash, operating results and current and anticipated cash needs. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility and, if the Company is not in default, it is required to obtain bank approval for dividend payments to shareholders outside of the credit facility group which comprises the Company’s subsidiaries in Colombia, Canada and the United States of America (the "Credit Facility Group").

Performance Graph



	12/31/2011	12/31/2012	12/31/2013	12/31/2014	12/31/2014	12/31/2016
Gran Tierra Energy Inc. (GTE)	100.0	114.8	152.3	80.2	45.2	62.9
S&P 500 Total Return (SPXT)	100.0	116.0	153.6	174.6	177.0	198.2
S&P O&G E&P Select Index Total Return (SPSIOP)	100.0	103.1	131.1	91.6	58.0	79.5

The information in this Form 10-K appearing under the heading "Performance Graph" is being "furnished" pursuant to Item 2.01(e) of Regulation S-K under the Securities Act and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 2.01(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act and shall not be deemed incorporated by reference into any filing under the Securities Act or the Exchange Act except to the extent that we specifically incorporate it by reference into such filing.

Item 6. ***Selected Financial Data***
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

Statement of Operations Data

	Year Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Oil and natural gas sales	**$ 289,269**	$ 276,011	559,398	$ 646,955	$ 503,467
Operating expenses	**86,925**	75,565	89,753	91,223	65,562
Transportation	**31,776**	40,204	24,196	18,949	26,645
Depletion, depreciation and accretion	**139,535**	176,386	185,877	200,851	130,370
Asset impairment	**616,649**	323,918	265,126	2,000	20,200
G&A expenses	**33,218**	32,353	51,249	41,115	46,659
Transaction expenses	**7,325**	—	—	—	—
Severance expenses	**1,319**	8,990	—	—	—
Equity tax	**3,098**	3,769	—	—	—
Foreign exchange (gain) loss	**(1,469)**	(17,242)	(39,535)	(18,693)	28,727
Financial instruments loss (gain)	**10,279**	2,027	4,722	—	—
Other loss	**—**	—	—	4,400	—
Other gain	**(929)**	(502)	(2,000)	—	(9,336)
Interest expense	**14,145**	—	—	—	—
	941,871	645,468	579,388	339,845	308,827
Interest income	**2,368**	1,369	2,856	2,174	1,709
(Loss) income from continuing operations before income taxes	**(650,234)**	(368,088)	(17,134)	309,284	196,349
Current income tax expense	**(20,122)**	(15,383)	(92,865)	(157,126)	(69,453)
Deferred income tax recovery (expense)	**204,791**	115,442	(34,350)	28,865	(26,814)
	184,669	100,059	(127,215)	(128,261)	(96,267)
(Loss) income from continuing operations	**(465,565)**	(268,029)	(144,349)	181,023	100,082
Loss from discontinued operations, net of income taxes	**—**	—	(26,990)	(54,735)	(423)
Net (loss) income	**$ (465,565)**	$ (268,029)	(171,339)	$ 126,288	$ 99,659
(LOSS) INCOME PER SHARE					
BASIC					
(LOSS) INCOME FROM CONTINUING OPERATIONS	**$ (1.45)**	$ (0.94)	$ (0.51)	$ 0.64	$ 0.35
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	**—**	—	(0.09)	(0.19)	—
NET (LOSS) INCOME	**$ (1.45)**	$ (0.94)	$ (0.60)	$ 0.45	$ 0.35

DILUTED

	2016	2015	2014	2013	2012
(LOSS) INCOME FROM CONTINUING OPERATIONS	**$ (1.45)**	$ (0.94)	$ (0.51)	$ 0.63	$ 0.35
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	**—**	—	(0.09)	(0.19)	—
NET (LOSS) INCOME	**$ (1.45)**	$ (0.94)	$ (0.60)	$ 0.44	$ 0.35

Balance Sheet Data

	As at December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Cash and cash equivalents	**$ 25,175**	$ 145,342	$ 331,848	$ 428,800	$ 212,624
Working capital (deficiency) surplus including cash)	**(23,344)**	160,449	239,312	244,764	220,288
Oil and gas properties	**1,060,093**	780,360	1,117,931	1,250,070	1,196,661
Deferred tax asset - long-term	**1,611**	3,241	2,153	3,663	3,918
Total assets	**1,367,896**	1,146,118	1,714,050	1,904,550	1,732,875
Long-term debt	**197,083**	—	—	—	—
Deferred tax liability - long-term	**107,230**	34,592	176,364	178,275	225,532
Total long-term liabilities	**353,880**	70,485	213,039	209,270	250,396
Shareholders’ equity	**858,987**	1,001,642	1,276,685	1,429,908	1,291,431

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

Additionally, on January 25, 2016, we acquired all of the issued and outstanding common shares of PGC for cash consideration. The net purchase price of PGC was $19.4 million, after giving effect to net working capital of $18.3 million. PGC's working capital on the acquisition date included restricted cash of $18.6 million and cash of $0.2 million. All of the opening balance of restricted cash was released prior to December 31, 2016. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra.

On August 23, 2016, we acquired all of the issued and outstanding common shares of PetroLatina for $525.0 million, consisting of: cash consideration of $465.7 million, which included a deferred cash payment of $25.0 million that was paid in December 31, 2016; assumption of a reserve-backed credit facility with an outstanding balance of $80.0 million; and net of working capital of $17.3 million and other closing adjustments. Upon completion of the transaction, we repaid and canceled the reserve-based credit facility and PetroLatina became an indirect wholly-owned subsidiary of Gran Tierra. The PetroLatina acquisition was funded through a combination of our existing cash balance, gross proceeds of $173.5 million from the subscription receipts offering noted below, available borrowings under our existing revolving credit facility and $130.0 million of borrowings under a bridge loan facility.

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. During the year ended December 31, 2016, we sold these Madalena shares. In accordance with GAAP, we met the criteria to classify our Argentina business unit as discontinued operations in the second quarter of 2014. 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 4, "Discontinued Operations," of our consolidated financial statements for the three years ended December 31, 2016.

Item 7. *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 Annual Report on Form 10-K regarding the identification of and risks relating to forward-looking statements, as well as Part I, Item 1A "Risk Factors" in this Annual Report on Form 10-K.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements and Supplementary Data" as set out in Part II, Item 8 of this Annual Report on Form 10-K.

Overview

We are an independent international energy company incorporated in the State of Delaware and engaged in oil and gas acquisition, exploration, development and production. We are strategically focused on onshore oil and gas properties in Colombia and also own the rights to oil and gas properties in Brazil and Peru. Our Colombian properties represented 87% of our proved reserves NAR at December 31, 2016. The remainder of our proved reserves were attributable to our Brazilian properties. For the year ended December 31, 2016, 97% (year ended December 31, 2015 - 97%; year ended December 31, 2014 - 95%) of our revenue and other income was generated in Colombia. We are headquartered in Calgary, Alberta, Canada.

As of December 31, 2016, we had estimated proved reserves NAR of 52.8 MMBOE, of which 72% were proved developed reserves and 98% were oil.

On February, 6, 2017, we announced that a purchase and sale agreement had been executed by a third party ("Purchaser") to purchase our Brazil business unit through the acquisition of all of the equity interests in one of our indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising our Brazil business unit to the Gran Tierra group of companies.

Upon completion of the Brazil Divestiture, the Purchaser will acquire all of our assets and certain liabilities in Brazil, including our 100% working interest in the Tiê Field and all of our interest in exploration rights and obligations held pursuant to concession agreements granted by the ANP.

The completion of the Brazil Divestiture is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP. The consideration to be received on the completion of the Brazil Divestiture is $35 million, subject to adjustments, plus the assumption by Purchaser of certain existing and potential liabilities of our Brazil business unit. Pursuant to the Agreement, the Purchaser paid a deposit of $3.5 million on February 7, 2017, which is not refundable in the event the Purchaser is not successful in obtaining financing to complete the Brazil Divestiture.

The economic effective date of the transaction will be on or before August 1, 2017, and we will continue to operate our Brazil business unit until the completion of the Brazil Divestiture.

2016 Acquisitions

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

Additionally, on January 25, 2016, we acquired all of the issued and outstanding common shares of PGC for cash consideration. The net purchase price of PGC was $19.4 million, after giving effect to net working capital of $18.3 million. PGC's working capital on the acquisition date included restricted cash of $18.6 million and cash of $0.2 million. All of the opening balance of restricted cash was released prior to December 31, 2016. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra.

On August 23, 2016, we acquired all of the issued and outstanding common shares of PetroLatina for $525.0 million, consisting of: cash consideration of $465.7 million, which included a deferred cash payment of $25.0 million that was paid on December 31, 2016; assumption of a reserve-backed credit facility with an outstanding balance of $80.0 million; and net of working capital of $17.3 million and other closing adjustments. Upon completion of the transaction, we repaid and canceled the reserve-based credit facility and PetroLatina became an indirect wholly-owned subsidiary of Gran Tierra. The PetroLatina acquisition was funded through a combination of existing cash, gross proceeds of $173.5 million from the subscription receipts offering noted below, available borrowings under our existing revolving credit facility and $130.0 million of borrowings under a bridge loan facility.

On November 25, 2016, we submitted winning bids totaling a combined $30.4 million for two blocks which Ecopetrol offered as part of an asset disposition process. Our winning bids were on the Santana and Nancy-Burdine-Maxine Blocks, which are located in the Putumayo Basin. Ecopetrol will transfer ownership of the blocks' assets, contracts, permits and licenses, as well as 100% ownership of Ecopetrol's rights and obligations in respect of the oil and gas assets, to us once the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) grants approval and the conditions of the assignment agreement are met. We intend to finance the $30.4 million purchase price with borrowings under our revolving credit facility.

The following table summarizes the acquisitions we completed during the year ended December 31, 2016:

	PetroLatina	PetroAmerica	PGC	Total
Net purchase price (net of working capital acquired) ($000s)	$ 525,000	$ 72,234	$ 19,388	$ 616,622

Debt and equity offerings

During April 2016, we issued $115 million aggregate principal amount of 5.00% Convertible Senior Notes due 2021 in a private placement to qualified institutional buyers. Net proceeds from the sale of the Notes were $109.1 million, after deducting the initial purchasers' discount and the offering expenses. The Notes bear interest at a rate of 5.00% per year.

On July 8, 2016, we issued approximately 57.8 million subscription receipts in a private placement to eligible purchasers at a price of $3.00 per Subscription Receipt for gross proceeds of approximately $173.5 million or net proceeds after share issuance costs of $165.8 million. The proceeds were used to partially fund the PetroLatina acquisition. Each Subscription Receipt entitled the holder to automatically receive one common share of Gran Tierra upon closing of the PetroLatina acquisition upon the satisfaction of certain conditions, which occurred on August 23, 2016.

On November 16, 2016, the borrowing base on our revolving credit facility was increased from $185.0 million, with $160.0 million readily available and $25.0 million subject to the consent of all lenders, to $250 million readily available. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. The borrowing base will be re-determined no later than May 2017.

On November 29, 2016, we issued approximately 43.3 million shares of common stock at a public offering price of $3.00 per share, for aggregate gross proceeds of approximately $130.0 million. The proceeds were used to repay borrowings outstanding under our revolving credit facility.

Colombian peace deal

On September 26, 2016, the Colombian government and the FARC signed a peace agreement and, on November 30, 2016, the Peace Agreement was ratified by Colombia's government. Pursuant to the Peace Agreement, the FARC agreed to demobilize its troops and urban militia members and to hand over its weapons to a United Nations mission within 180 days. Once demobilized and disarmed, the FARC can become a legal political party. Under the Peace Agreement, the FARC will be guaranteed at least five seats in the Senate and another five seats in the House of Representatives in 2018 congressional elections, even if they don’t get enough votes for those seats.

Highlights

	Year Ended December 31,				
SEC Compliant Reserves, NAR (MMBOE)	**2016**	**% Change**	**2015**	**% Change**	**2014**
Estimated Proved Oil and Gas Reserves, NAR, at December 31	**52.8**	36	38.9	5	37.0
Estimated Probable Oil and Gas Reserves, NAR, at December 31	**44.2**	182	15.7	16	13.5
Estimated Possible Oil and Gas Reserves, NAR, at December 31	**63.6**	405	12.6	(18)	15.4
Volumes (BOE)					
Working Interest Production Before Royalties	**9,904,893**	16	8,541,393	(7)	9,191,467
Royalties	**(1,418,599)**	(1)	(1,428,088)	(34)	(2,153,013)
Production NAR	**8,486,294**	19	7,113,305	1	7,038,454
Decrease (Increase) in Inventory	**280,356**	(163)	(448,562)	62	(277,485)
Sales[(1)]	**8,766,650**	32	6,664,743	(1)	6,760,969
Average Daily Volumes (BOEPD)					
Working Interest Production Before Royalties	**27,062**	16	23,401	(7)	25,182
Royalties	**(3,875)**	(1)	(3,912)	(34)	(5,899)
Production NAR	**23,187**	19	19,489	1	19,283
Decrease (Increase) in Inventory	**767**	(162)	(1,229)	62	(760)
Sales[(1)]	**23,954**	31	18,260	(1)	18,523
Operating Netback ($000s)					
Oil and Gas Sales	**$ 289,269**	5	$ 276,011	(51)	$ 559,398
Operating Expenses	**(86,925)**	15	(75,565)	(16)	(89,753)
Transportation expenses	**(31,776)**	(21)	(40,204)	66	(24,196)
Operating Netback[(2)]	**$ 170,568**	6	$ 160,242	(64)	$ 445,449
General and Administrative Expenses ("G&A"), Including Stock-Based Compensation ($000s)	**$ 33,218**	3	$ 32,353	(37)	$ 51,249
Net Loss ($000s)	**$ (465,565)**	74	$ (268,029)	56	$ (171,339)
EBITDA[(3)]	**$ 120,095**	(9)	$ 132,216	(70)	$ 433,869
Adjusted EBITDA[(3)]	**$ 117,697**	2	$ 114,974	(71)	$ 394,334
Net Cash Provided by Operating Activities of Continuing Operations ($000s)	**$ 93,042**	49	$ 62,305	(72)	$ 220,952
Funds Flow From Continuing Operations ($000s) [(4)]	**$ 104,984**	(2)	$ 107,570	(66)	$ 317,184
Capital Expenditures ($000s)	**$ 127,789**	(18)	$ 156,639	(60)	$ 391,526
Cash Paid for Acquisitions, Net of Cash Acquired - PetroAmerica, PGC and PetroLatina ($000s)	**$ 522,031**	—	$ —	—	$ —

(Thousands of U.S. Dollars)	As at December 31, 2016	% Change	2015	% Change	2014
Cash, Cash Equivalents and Current Restricted Cash	**$ 33,497**	(77)	$ 145,434	(56)	$ 333,684
Working Capital (Deficiency) Surplus, Including Cash and Cash Equivalents	**$ (23,344)**	(115)	$ 160,449	(33)	$ 239,312
Revolving Credit Facility	**$ 90,000**	—	$ —	—	$ —
Convertible Senior Notes	**$ 115,000**	—	$ —	—	$ —

All probable and possible reserves associated with the Bretaña Field on Block 95 in Peru were reclassified as contingent resources in a report with an effective date of January 31, 2015. These reserves are excluded from the table above.

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

Non-GAAP measures

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

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

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

EBITDA - Non-GAAP Measure ($000s)	Year Ended December 31, 2016	2015	2014
Net loss	**$ (465,565)**	$ (268,029)	$ (171,339)
Adjustments to reconcile net loss to EBITDA			
DD&A expenses	**139,535**	176,386	185,877
Asset impairment	**616,649**	323,918	265,126
Interest expense	**14,145**	—	—
Income tax (recovery) expense	**(184,669)**	(100,059)	127,215
Loss from discontinued operations, net of income taxes	**—**	—	26,990
EBITDA	**120,095**	132,216	433,869
Gain on acquisition	**(929)**	—	—
Foreign exchange gain	**(1,469)**	(17,242)	(39,535)
Adjusted EBITDA	**$ 117,697**	$ 114,974	$ 394,334

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

Funds Flow From Continuing Operations - Non-GAAP Measure ($000s)	Fourth Quarter 2016	Third Quarter 2016	Fourth Quarter 2015	Year Ended December 31, 2016	2015	2014
Net cash provided by operating activities of continuing operations	$ 6,643	$ 48,222	$ 3,726	$ 93,042	$ 62,305	$ 220,952
Adjustments to reconcile net cash provided by operating activities to funds flow from continuing operations						
Net change in assets and liabilities from operating activities	29,434	(24,727)	11,680	11,337	39,048	95,436
Cash settlement of asset retirement obligation	109	32	1,449	605	6,217	796
Funds flow from continuing operations	$ 36,186	$ 23,527	$ 16,855	$ 104,984	$ 107,570	$ 317,184

Consolidated Results of Operations

	Year Ended December 31,				
(Thousands of U.S. Dollars)	2016	% Change	2015	% Change	2014
Oil and natural gas sales	$ 289,269	5	$ 276,011	(51)	$ 559,398
Operating expenses	86,925	15	75,565	(16)	89,753
Transportation expenses	31,776	(21)	40,204	66	24,196
Operating netback[1]	170,568	6	160,242	(64)	445,449
DD&A expenses	139,535	(21)	176,386	(5)	185,877
Asset impairment	616,649	90	323,918	22	265,126
G&A expenses, including stock-based compensation	33,218	3	32,353	(37)	51,249
Transaction expenses	7,325	—	—	—	—
Severance expenses	1,319	(85)	8,990	—	—
Equity tax	3,098	(18)	3,769	—	—
Foreign exchange gain	(1,469)	91	(17,242)	56	(39,535)
Financial instruments loss	10,279	407	2,027	(57)	4,722
Interest expense	14,145	—	—	—	—
Other gain	(929)	(85)	(502)	75	(2,000)
	823,170	55	529,699	14	465,439
Interest income	2,368	73	1,369	(52)	2,856
Loss from continuing operations before income taxes	(650,234)	(77)	(368,088)	(2,048)	(17,134)
Current income tax expense	(20,122)	31	(15,383)	(83)	(92,865)
Deferred income tax recovery (expense)	204,791	(77)	115,442	(436)	(34,350)
	184,669	85	100,059	(179)	(127,215)
Loss from continuing operations	(465,565)	(74)	(268,029)	(86)	(144,349)
Loss from discontinued operations, net of income taxes	—	—	—	(100)	(26,990)
Net loss	$ (465,565)	(74)	$ (268,029)	(56)	$ (171,339)

Sales Volumes					
Oil and NGL's, bbl	**8,667,528**	31	6,611,680	(1)	6,706,083
Natural gas, Mcf	**594,730**	87	318,379	(3)	329,312
Total sales volumes, BOE	**8,766,650**	32	6,664,743	(1)	6,760,968
Total sales volumes, BOEPD	**23,954**	31	18,260	(1)	18,523
Average Prices					
Oil and NGL's per bbl	**$ 33.22**	(20)	$ 41.56	(50)	$ 83.22
Natural gas per Mcf	**$ 2.22**	(42)	$ 3.80	(16)	$ 4.52
Brent Price per bbl	**$ 44.33**	(15)	$ 52.35	(47)	$ 99.02
Consolidated Results of Operations per BOE Sales Volumes					
Oil and natural gas sales	**$ 33.00**	(20)	$ 41.41	(50)	$ 82.74
Operating expenses	**9.92**	(13)	11.34	(15)	13.28
Transportation expenses	**3.62**	(40)	6.03	68	3.58
Operating netback[1]	**19.46**	(19)	24.04	(64)	65.88
DD&A expenses	**15.92**	(40)	26.47	(4)	27.49
Asset impairment	**70.34**	45	48.60	—	39.21
G&A expenses, including stock-based compensation	**3.79**	(22)	4.85	(36)	7.58
Transaction expenses	**0.84**	—	0.00	—	0.00
Severance expenses	**0.15**	(89)	1.35	—	—
Equity tax	**0.35**	(39)	0.57	—	—
Foreign exchange gain	**(0.17)**	93	(2.59)	56	(5.85)
Financial instruments loss	**1.17**	290	0.30	(57)	0.70
Interest expense	**1.61**	—	—	—	—
Other gain	**(0.11)**	(38)	(0.08)	73	(0.30)
	93.89	(18)	79.47	(15)	68.83
Interest income	**0.27**	29	0.21	(50)	0.42
Loss from continuing operations before income taxes	**(74.16)**	(34)	(55.22)	2,083	(2.53)
Current income tax expense	**(2.30)**	—	(2.31)	(83)	(13.74)
Deferred income tax recovery (expense)	**23.36**	(35)	17.32	(441)	(5.08)
	21.06	40	15.01	180	(18.82)
Loss from continuing operations	**$ (53.10)**	(32)	$ (40.21)	(88)	$ (21.35)

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

Consolidated Results of Continuing Operations for the Year Ended December 31, 2016, Compared with the Results for the Years Ended December 31, 2015 and 2014

Oil and Gas Production and Sales Volumes, BOEPD

	Year Ended December 31,		
Average Daily Volumes (BOEPD) - Colombia	**2016**	**2015**	**2014**
Working Interest Production Before Royalties	**26,216**	22,794	24,128
Royalties	**(3,746)**	(3,822)	(5,749)
Production NAR	**22,470**	18,972	18,379
Decrease (Increase) in Inventory	**771**	(1,231)	(760)
Sales	**23,241**	17,741	17,619
Royalties, % of Working Interest Production Before Royalties	**14%**	17%	24%

	Year Ended December 31,		
Average Daily Volumes (BOEPD) - Brazil	**2016**	**2015**	**2014**
Working Interest Production Before Royalties	**846**	607	1,054
Royalties	**(129)**	(90)	(150)
Production NAR	**717**	517	904
(Increase) Decrease in Inventory	**(4)**	2	—
Sales	**713**	519	904
Royalties, % of Working Interest Production Before Royalties	**15%**	15%	14%

	Year Ended December 31,		
Average Daily Volumes (BOEPD) - Total	**2016**	**2015**	**2014**
Working Interest Production Before Royalties	**27,062**	23,401	25,182
Royalties	**(3,875)**	(3,912)	(5,899)
Production NAR	**23,187**	19,489	19,283
Decrease (Increase) in Inventory	**767**	(1,229)	(760)
Sales	**23,954**	18,260	18,523
Royalties, % of Working Interest Production Before Royalties	**14%**	17%	23%

Oil and gas production NAR for the year ended December 31, 2016, increased by 19% to 23,187 BOEPD compared with 19,489 BOEPD in 2015. Production increased as a result of the Petroamerica and PetroLatina acquisitions and a successful drilling campaign in the Costayaco, Moqueta and Acordionero Fields in Colombia.

Oil and gas production NAR for the year ended December 31, 2015, increased by 1% to 19,489 BOEPD compared with 19,283 BOEPD in 2014. In 2015 in Colombia, production from new wells in the Moqueta Field in the Chaza Block and increased production from the Jilguero Field in the Garibay Block, as a result of the unitization of that field and new wells coming on stream, was offset by the impact of normal field production declines in the Costayaco Field in the Chaza Block and the Juanambu Field in the Guayuyaco Block.

Oil and gas sales volumes for the year ended December 31, 2016, increased by 31% to 23,954 BOEPD compared with 18,260 BOEPD in 2015. During the year ended December 31, 2016, an oil inventory decrease accounted for 767 bopd of the increased sales compared with an oil inventory increase in 2015 which accounted for 1,229 bopd of the reduced sales. Oil and gas sales volumes for the year ended December 31, 2015, decreased by 1% to 18,260 BOEPD compared with 18,523 BOEPD in 2014. During the year ended December 31, 2015, an oil inventory increase accounted for 1,229 bopd of reduced sales compared with an oil inventory increase in 2014 which accounted for 760 bopd of reduced sales.

Operating Netbacks

Colombia	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Oil and Gas Sales	**$ 280,872**	$ 269,035	$ 532,196
Transportation Expenses	**(31,347)**	(40,083)	(23,704)
	249,525	228,952	508,492
Operating Expenses	**(84,794)**	(69,323)	(83,397)
Operating Netback(1)	**$ 164,731**	$ 159,629	$ 425,095
(U.S. Dollars per BOE)			
Oil and Gas Sales	**$ 33.02**	$ 41.55	$ 82.76
Transportation Expenses	**(3.69)**	(6.19)	(3.69)
	29.33	35.36	79.07
Operating Expenses	**(9.97)**	(10.71)	(12.97)
Operating Netback(1)	**$ 19.36**	$ 24.65	$ 66.10

Brazil	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Oil and Gas Sales	**$ 8,397**	$ 6,976	$ 27,202
Transportation Expenses	**(429)**	(121)	(492)
	7,968	6,855	26,710
Operating Expenses	**(2,131)**	(6,242)	(6,356)
Operating Netback(1)	**$ 5,837**	$ 613	$ 20,354
(U.S. Dollars per BOE)			
Oil and Gas Sales	**$ 32.22**	$ 36.84	$ 82.42
Transportation Expenses	**(1.65)**	(0.64)	(1.49)
	30.57	36.20	80.93
Operating Expenses	**(8.18)**	(32.97)	(19.26)
Operating Netback(1)	**$ 22.39**	$ 3.23	$ 61.67

Total	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Oil and Gas Sales	**$ 289,269**	$ 276,011	$ 559,398
Transportation Expenses	**(31,776)**	(40,204)	(24,196)
	257,493	235,807	535,202
Operating Expenses	**(86,925)**	(75,565)	(89,753)
Operating Netback(1)	**$ 170,568**	$ 160,242	$ 445,449
(U.S. Dollars per BOE)			
Oil and Gas Sales	**$ 33.00**	$ 41.41	$ 82.74
Transportation Expenses	**(3.62)**	(6.03)	(3.58)
	29.38	35.38	79.16
Operating Expenses	**(9.92)**	(11.34)	(13.28)
Operating Netback(1)	**$ 19.46**	$ 24.04	$ 65.88

U.S. Dollars Per BOE			
Brent	**$ 44.33**	$ 52.35	$ 99.02
WTI	**$ 43.15**	$ 48.78	$ 93.00

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

Oil and gas sales for the year ended December 31, 2016, increased to $289.3 million from $276.0 million in 2015 primarily as a result of the effect of increased sales, partially offset by decreased average realized oil prices. Oil and gas sales for the year ended December 31, 2015, decreased to $276.0 million from $559.4 million in 2014 as a result of the combined effect of decreased sales and realized oil prices.

The following table shows the effect of changes in realized price and sales volumes on our oil and gas sales for the three years ended December 31, 2016:

	Year Ended December 31,		
	2016	**2015**	**2014**
Oil and natural gas sales for the comparative period	**$ 276,011**	$ 559,398	$ 646,955
Realized sales price decrease effect	**(73,782)**	(275,425)	(63,495)
Sales volume increase (decrease) effect	**87,040**	(7,962)	(24,062)
Oil and natural gas sales for the current period	**$ 289,269**	$ 276,011	$ 559,398

Average realized prices decreased by 20% to $33.00 per BOE for the year ended December 31, 2016, from $41.41 per BOE for 2015, and decreased by 50% to $41.41 per BOE for the year ended December 31, 2015, from $82.74 per BOE for 2014. The realized price decreases were commensurate with decreased in benchmark oil prices. Average Brent oil prices for the year ended December 31, 2016, decreased by 15% compared with 2015, and decreased by 47% compared with 2014. Additionally, beginning July 1, 2014, the port operations fee component of the 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 CENIT S.A-operated Trans-Andean oil pipeline (the "OTA pipeline") disruptions, we have multiple transportation alternatives. Each transportation route has varying effects on realized prices and transportation costs. The following table shows the percentage of oil volumes we sold in Colombia using each transportation method for the three years ended December 31, 2016:

	Year Ended December 31,		
	2016	**2015**	**2014**
Volume sold transported through pipelines	**44%**	54%	53%
Volume sold at wellhead, trucking	**43%**	30%	41%
Volume sold not at wellhead, trucking	**13%**	16%	6%
	100%	100%	100%

Transportation expenses for the year ended December 31, 2016, were $31.8 million, or $3.62 per BOE, compared with $40.2 million, or $6.03 per BOE, in 2015. On a per BOE basis, transportation expenses decreased by 40%. The decrease in transportation expenses per BOE was primarily due to a lower percentage of volumes sold using pipelines, as noted in the table above, and the use of alternative transportation routes, which had lower costs per BOE than the routes used in 2015.

Transportation expenses for the year ended December 31, 2015, were $40.2 million, or $6.03 per BOE, compared with $24.2 million, or $3.58 per BOE, in 2014. On a per BOE basis, transportation expenses increased by 68%. The increase in transportation expenses per BOE was primarily due to the alternative transportation routes used during periods of OTA pipeline disruptions. During 2015, we used new alternative transportation routes which carried higher transportation costs, but higher realized prices compared with other delivery points.

Operating expenses for the year ended December 31, 2016, were $86.9 million, or $9.92 per BOE, compared with $75.6 million, or $11.34 per BOE in 2015. On a per BOE basis, operating expenses decreased by 13%. The decrease in operating expenses per BOE in 2016 was primarily due to Colombian operating cost savings, partially offset by the effect of the weakening of the U.S. dollar against local currencies in South America. Workover expenses increased by $0.38 per BOE to

$2.60 per BOE compared with the prior year. Excluding workover expenses, operating costs decreased by $1.80 per BOE to $7.32 per BOE.

Operating expenses for the year ended December 31, 2015, were $75.6 million, or $11.34 per BOE, compared with $89.8 million, or $13.28 per BOE, in 2014. Operating expenses per BOE decreased in 2015 primarily due to Colombian operating cost savings and the effect of the strengthening of the U.S. dollar against local currencies in South America. In Brazil, in the year ended December 31, 2015, we incurred $1.7 million, of one-time penalties relating to alleged non-compliance with certain requirements regarding the health and safety management system, identified during a safety and operational audit conducted by the ANP in early 2015.

DD&A Expenses

	Year Ended December 31, 2016		Year Ended December 31, 2015	
	DD&A expenses, thousands of U.S. Dollars	**DD&A expenses, U.S. Dollars Per BOE**	**DD&A expenses, thousands of U.S. Dollars**	**DD&A expenses, U.S. Dollars Per BOE**
Colombia	**$ 132,569**	**$ 15.59**	$ 167,701	$ 25.90
Brazil	**3,819**	**14.65**	6,183	32.66
Peru	**544**	**—**	789	—
Corporate	**2,603**	**—**	1,713	—
	$ 139,535	**$ 15.92**	$ 176,386	$ 26.47

	Year Ended December 31, 2014	
	DD&A expenses, thousands of U.S. Dollars	**DD&A expenses, U.S. Dollars Per BOE**
Colombia	$ 174,063	$ 27.07
Brazil	9,932	30.09
Peru	690	—
Corporate	1,192	—
	$ 185,877	$ 27.49

DD&A expenses for the year ended December 31, 2016, decreased to $139.5 million ($15.92 per BOE) from $176.4 million ($26.47 per BOE) in 2015, and from $185.9 million ($27.49 per BOE) in 2014. On a per BOE basis, the decreases in both years were due to lower costs in the depletable base and increased proved reserves at year end.

Asset Impairment

We follow the full cost method of accounting for our oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated “ceiling”. The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year and it should not be assumed that estimates of future net revenues represent the fair market value of our reserves. In accordance with GAAP, we used an average Brent price of $42.92 per bbl for the purposes of the December 31, 2016 ceiling test calculations (December 31, 2015 - $54.08 per bbl).

(Thousands of U.S. Dollars)	Year Ended December 31, 2016	2015	2014
Impairment of oil and gas properties			
Colombia	**$ 513,650**	$ 232,436	$ —
Brazil	**71,143**	46,933	—
Peru	**31,192**	41,916	265,126
	615,985	321,285	265,126
Impairment of inventory	**664**	2,633	—
	$ 616,649	$ 323,918	$ 265,126

In the year ended December 31, 2016, ceiling test impairment losses in our Colombia cost center and inventory impairment losses were primarily due to lower oil prices and because the acquisitions of PetroLatina and PetroAmerica were initially added into the cost base at fair value. These acquired assets were then subjected to a prescribed U.S. GAAP ceiling test, which is not a fair value test, and which, as noted above, uses constant commodity pricing that averages prices during the preceding 12 months.

In the year ended December 31, 2016, the ceiling test impairment loss in our Brazil cost center related to lower oil prices and increased costs in the depletable base as a result of a $45.0 million impairment of unproved properties. Impairment losses in our Peru cost center included costs incurred on Block 95 and an impairment of costs incurred on Blocks 123 and 129. In the three months ended September 30, 2016, we ceased the impairment of costs incurred on Block 95 as a result of the effect of a revised field development plan for the Block.

In the year ended December 31, 2015, ceiling test impairment losses in our Colombia and Brazil cost centers and inventory impairment losses were primarily due to lower oil prices. The ceiling test impairment loss in our Brazil cost center was recognized during the first three quarters of 2015. As a result of a technical evaluation of the Brazil cost center reserves completed during the fourth quarter of 2015, an upward technical revision in proved reserves resulted in no ceiling test impairment loss during that quarter. Impairment losses in our Peru cost center related to costs incurred on Block 95.

In the year ended December 31, 2014, impairment losses in our Peru cost center related to costs incurred on Block 95.

G&A Expenses

(Thousands of U.S. Dollars)	Year Ended December 31, 2016	2015	2014
G&A Expenses	**$ 33,218**	$ 32,353	$ 51,249
U.S. Dollars Per BOE			
G&A Expenses, Including Stock-Based Compensation	**$ 3.79**	$ 4.85	$ 7.58

G&A expenses for the year ended December 31, 2016, of $33.2 million were comparable to 2015. Savings due to cost control initiatives were offset by higher stock-based compensation expense as a result of PSUs and DSUs granted during 2016 and a higher year-end share price, and lower capitalization of costs as a result of lower capital activity. G&A expenses per BOE in the year ended December 31, 2016, of $3.79 were 22% lower compared with $4.85 in 2015 due to increased sales volumes.

G&A expenses for the year ended December 31, 2015, of $32.4 million decreased by 37% from $51.2 million in 2014. These decreases were mainly due to reductions in the number of our employees as part of cost saving measures, a focus on reductions of our other G&A expenses and the effect of the strengthening of the U.S. dollar against local currencies in South America and Canada, which resulted in savings for costs denominated in local currency. Additionally, G&A expenses in the year ended December 31, 2015, were net of a credit of $2.6 million relating to the reversal of stock-based compensation expense for unvested options and RSUs associated with terminated employees. These G&A expense reductions were partially offset by lower allocations to capital projects due to lower capital activity and deferred financing fees expensed as a result of the cancellation of our previous credit facility.

Transaction Expenses

For the year ended December 31, 2016, transaction expenses were $7.3 million, compared with nil in 2015 and 2014. Transaction expenses related to our acquisitions of PetroLatina and Petroamerica.

Severance Expenses

For the year ended December 31, 2016, severance expenses were $1.3 million compared with $9.0 million in 2015 and $nil in 2014. Severance expenses were consistent with the decrease in headcount.

Equity Tax Expense

For the years ended December 31, 2016, and 2015, equity tax expense was $3.1 million and $3.8 million, respectively, and represented a Colombian tax which was calculated based on our Colombian legal entities' balance sheet equity for tax purposes at January 1. The legal obligation for each year's equity tax liability arises on January 1 of each year, therefore, we recognize the annual amounts of the equity tax expense in our consolidated statement of operations during the first quarter of each year.

Foreign Exchange Gains

For the years ended December, 2016, 2015 and 2014, we had foreign exchange gains of $1.5 million, $17.2 million and $39.5 million, respectively. Under U.S. GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation was the main source of the foreign exchange gains.

The following table presents the change in the Colombian peso against the U.S. dollar for the three years ended December 31, 2016:

	Year Ended December 31,		
	2016	**2015**	**2014**
Change in the Colombian peso against the U.S. dollar	**strengthened by 5%**	weakened by 32%	weakened by 24%

Financial Instrument Gains and Losses

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Trading securities loss	**$ 3,925**	$ 1,335	$ 6,326
Commodity price derivative loss	**7,370**	—	—
Foreign currency derivatives (gain) loss	**(1,016)**	692	(1,604)
	$ 10,279	$ 2,027	$ 4,722

Trading securities losses related to losses on the Madalena shares we received in connection with the sale of our Argentina business unit in June 2014. During the year ended December 31, 2016, we sold all of these shares for cash proceeds of $2.3 million.

During 2016, we entered into commodity price derivative contracts to manage the variability in cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we could execute at least a portion of our capital spending. We also entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated operating costs.

In 2015, foreign currency derivative gains related to our Colombian peso non-deliverable forward contracts, which were purchased for purposes of fixing the exchange rate at which we would purchase or sell Colombian pesos to settle our income tax installments and payments.

Other Gains

Other gain in the year ended December 31, 2016, related to a gain on the acquisition of Petroamerica. Other gains in the years ended December 31, 2015 and 2014, related to a contingent loss accrued in connection with a legal dispute.

Income Tax Expense and Recovery

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Loss from continuing operations before income tax	**$ (650,234)**	$ (368,088)	$ (17,134)
Current income tax expense	**$ (20,122)**	$ (15,383)	$ (92,865)
Deferred income tax recovery (expense)	**204,791**	115,442	(34,350)
Total income tax recovery (expense)	**$ 184,669**	$ 100,059	$ (127,215)
Effective tax rate	**28%**	27%	(742)%
Deferred income tax recovery related to Colombia ceiling test impairment	**$ 201,300**	$ 91,700	**$ —**

Current income tax expense was higher in the year ended December 31, 2016, compared with 2015 as a result of higher taxable income in Colombia. Current income tax expense was lower in the year ended December 31, 2015, compared with 2014 as a result of lower taxable income in Colombia.

The deferred income tax recovery for the year ended December 31, 2016, of $204.8 million included $201.3 million associated with ceiling test impairment losses in Colombia compared with the deferred income tax recovery for the year ended December 31, 2015, of $115.4 million which included $91.7 million associated with ceiling test impairment losses in Colombia. In each year income tax recovery associated with impairment losses in Peru and Brazil was offset by a full valuation allowance.

Our effective tax rate was 28% for the year ended December 31, 2016 compared with 27% in 2015. The increase in the effective tax rate was primarily due to a decrease in other permanent differences, non-deductible third party royalties and other local taxes, partially offset by an increase in the valuation allowance, the effect of foreign taxes, stock based compensation and foreign currency translation adjustments. Additionally, our income tax expense in 2016 reflected the impact of future income tax rate changes in Colombia on our deferred tax liability. In 2016, tax legislation was enacted in Colombia which reduced the 2017 and onwards tax rates resulting in a decrease of the future Colombian tax liability by approximately $4.1 million when tax effected at 40%.

In the year ended December 31, 2014, we had income tax expense despite having losses from continuing operations. In 2014, our loss before income taxes was primarily due to impairment losses in Peru which were fully offset by an increase in the valuation allowance. The increase in the effective tax rate for the year ended December 31, 2015, compared with 2014 was primarily due to a smaller increase in the valuation allowance as a result of lower impairment losses in Peru where there is a full valuation allowance and an increase in foreign currency translation adjustments. Additionally, our income tax expense in 2014 reflected the impact of future income tax rate changes in Colombia on our deferred tax liability. In 2014, tax legislation was enacted in Colombia which increased the 2015 to 2018 tax rates resulting in an increase of the Colombian deferred tax liability of approximately $31.0 million.

The difference between our effective tax rate of 28% for the year ended December 31, 2016, and the 35% U.S. statutory rate was primarily due to an increase in the valuation allowance, non-deductible third party royalties in Colombia, other local taxes, and stock based compensation, partially offset by the impact of foreign taxes and other permanent differences.

Loss from Discontinued Operations

On June 25, 2014, we sold our Argentina business unit for aggregate consideration of $69.3 million.

Funds Flow From Continuing Operations

For the year ended December 31, 2016, funds flow from continuing operations decreased by 2% to $105.0 million from $107.6 million in 2015. For the year ended December 31, 2016, our funds flow from operations was negatively affected by transaction costs of $7.3 million, For the year ended December 31, 2015, funds flow from continuing operations decreased by 66% from $317.2 million to $107.6 million, largely as a result of lower oil prices.

(Thousands of U.S. Dollars)	Fourth quarter 2016 compared with third quarter 2016	% change	Fourth quarter 2016 compared with fourth quarter 2015	% change	Year ended December 31, 2016 compared with year ended December 31, 2015	% change
Funds flow from operations for the comparative period	**$ 23,527**		**$ 16,855**		**$ 107,570**	
Increase (decrease) due to:						
Sales volumes	**15,928**		**30,365**		**87,040**	
Prices	**7,147**		**6,472**		**(73,782)**	
Expenses:						
Operating	**1,166**		**(10,220)**		**(11,360)**	
Transportation	**(1,685)**		**4,741**		**8,428**	
Cash G&A and RSU settlements, excluding stock-based compensation expense	**(5,912)**		**(4,349)**		**2,899**	
Transaction	**6,088**		**—**		**(7,325)**	
Severance	**(20)**		**2,143**		**7,671**	
Interest, net of amortization of debt issuance costs	**(487)**		**(3,425)**		**(8,454)**	
Realized foreign exchange gains	**(4,230)**		**(1,800)**		**(8,822)**	
Settlement of financial instruments	**(438)**		**—**		**4,187**	
Current taxes	**(4,563)**		**(4,691)**		**(4,739)**	
Other	**(335)**		**95**		**1,671**	
Net change in funds flow from comparative period	**12,659**	**54%**	**19,331**	**115%**	**(2,586)**	**(2)%**
Funds flow from operations for the current period	**$ 36,186**		**$ 36,186**		**$ 104,984**	

2017 Capital Program

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

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

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

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

2016 Capital Program

Capital expenditures during the year ended December 31, 2016, were $127.8 million:

(Thousands of U.S. Dollars)		
Colombia	**$**	**105,963**
Brazil		**15,146**
Peru		**5,059**
Corporate		**1,621**
	$	**127,789**

Colombia

The significant elements of our 2016 capital program in Colombia were:

- On the Chaza Block (100% working interest ("WI"), operated), we drilled and completed the Guriyaco-1 exploration well, which was completed as an oil producer. We completed the Costayaco-24 development well and drilled and completed the Costayaco-23i, Costayaco-27i, Moqueta-20, Moqueta 22, and Moqueta-23 development wells in the Costayaco and Moqueta Fields. All four wells were completed as oil producers. We performed recompletions on Costayaco-9 and Costayaco-19 in the A-Limestone formation, a new producing zone for the field. We also completed a dual completion on the Moqueta-19i water injector well.

- On the Midas Block (100% WI, operated), we drilled and completed the Acordionero-5 and Acordionero-7 development wells as oil producers and commenced drilling the Acordionero-8i development well.

- On the Putumayo-7 Block (100% WI, operated), we drilled and completed the Cumplidor-1 exploration well, which was completed as an oil producer, and commenced drilling of the Alpha-1 exploration well.

- On the Putumayo-4 Block (100% WI, operated), we continued activities related to environmental permitting for the Siriri-1 exploration well.

- On the El Porton Block (100% WI, operated), we continued activities related to environmental permitting and lease construction for the Prosperidad exploration well.

- On the Suroriente Block (15.8% WI, non-operated), we commenced a well workover campaign at the Cohembi and Quinde oil fields.

- We completed the acquisition of 2-D seismic on Sinu-1 (60% WI, operated) and Sinu-3 (51% WI, operated) Blocks.

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

Brazil

In Brazil, we commenced work on a water injection/pressure support project with a workover on the 1-GTE-7HPC-BA well to assess potential as a water source well and we continued facility improvements, including the completion of a compressed natural gas project and a flare stack.

Peru

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

Liquidity and Capital Resources

	As at December 31,				
(Thousands of U.S. Dollars)	**2016**	**% Change**	**2015**	**% Change**	**2014**
Cash and Cash Equivalents	**$ 25,175**	(83)	$ 145,342	(56)	$ 331,848
Current Restricted Cash	**$ 8,322**	—	$ 92	(95)	$ 1,836
Working Capital (Deficiency) Surplus, Including Cash and Cash Equivalents	**$ (23,344)**	(115)	$ 160,449	(33)	$ 239,312
Revolving Credit Facility	**$ 90,000**	—	$ —	—	$ —
Convertible Senior Notes	**$ 115,000**	—	$ —	—	$ —

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

PetroLatina Acquisition

As disclosed above, on August 23, 2016, we acquired all of the issued and outstanding common shares of PetroLatina for cash consideration of $465.7 million, which included a deferred cash payment of $25.0 million which was paid on December 31, 2016. The PetroLatina acquisition was funded through a combination of our cash on hand, gross proceeds of $173.5 million from the Subscription Receipts, available borrowings under our existing revolving credit facility and $130.0 million of borrowings under a Bridge Loan Facility.

Revolving Credit Facility and Bridge Loan Facility

At December 31, 2016, we had a revolving credit facility with a syndicate of lenders. On November 16, 2016, we entered into a Fourth Amendment (the "Fourth Amendment") to our credit agreement dated September 18, 2015 (the "Credit Agreement"). The Fourth Amendment, among other things, increased the borrowing base to $250 million readily available. Previously, the borrowing base was $185.0 million, with $160.0 million readily available and $25.0 million subject to the consent of all lenders. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. The borrowing base will be re-determined semi-annually with the next re-determination due to occur no later than May 2017. The credit agreement includes a letter of credit sub-limit of up to $100 million. None of the letter of credit sub-limit had been used at December 31, 2016. Borrowings under the revolving credit facility will mature on September 18, 2018.

Amounts drawn down under the revolving credit facility bear interest, at our option, at the USD LIBOR rate plus a margin ranging from 2.00% and 3.00% per annum, or an alternate base rate plus a margin ranging from 1.00% per annum to 2.00% per annum, in each case based on the borrowing base utilization percentage. The alternate base rate is currently the U.S. prime rate. Undrawn amounts under the revolving credit facility bear interest at 0.75% per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure.

On August 23, 2016, we entered into a Third Amendment to the Credit Agreement to add a bridge term loan facility, pursuant to which the lenders provided $130.0 million in secured bridge loan financing to fund a portion of the purchase price of the PetroLatina acquisition. The Bridge Loan Facility had a term of 364 days, bore interest at USD LIBOR plus 6%, and had customary bridge facility repayment terms, providing for the prepayment of the Bridge Loan Facility upon the occurrence of certain events, including certain debt issuances. It was otherwise on substantially the same terms as the existing secured revolving credit facility.

On August 23, 2016, in connection with the PetroLatina acquisition, we drew $95.0 million on our revolving credit facility and $130.0 million on our Bridge Loan Facility. During the three months ending December 31, 2016, upon the sale of non-core assets (Note 7), we repaid $5.0 million of the balance outstanding on the Bridge Loan Facility, and, concurrent with the effectiveness of the Fourth Amendment, repaid the remaining balance on our bridge loan facility using available borrowing capacity under our Credit Agreement. This resulted in a balance outstanding on our revolving credit facility of $190 million. We subsequently drew an additional $37.0 million on our revolving credit facility and repaid $137.0 million of the balance outstanding on this facility.

As part of the PetroLatina acquisition, we assumed PetroLatina's reserve-backed credit facility with an outstanding balance as at the PetroLatina acquisition Date of $80.0 million. This credit facility plus accrued interest was repaid by upon closing of the PetroLatina acquisition on August 23, 2016.

Under the terms of our credit facility, we are required to maintain compliance with certain financial and operating covenants which include: the maintenance of a ratio of debt, including letters of credit, to net income plus interest, taxes, depreciation, depletion, amortization, exploration expenses and all non-cash charges minus all non-cash income ("EBITDAX") not to exceed 4.00 to 1.0; the maintenance of a ratio of senior secured obligations to EBITDAX not to exceed 3.00 to 1.00; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5 to 1.0. As at December 31, 2016, we were in compliance with all financial and operating covenants in our credit agreement. Under the terms of the credit facility, we are limited in our ability to pay any dividends to our shareholders without bank approval.

Notes

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

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

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

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

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

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

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

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

At December 31, 2016, 93% of our cash and cash equivalents were held by subsidiaries and partnerships outside of Canada and the United States. This cash was generally not available to fund domestic or head office operations unless funds were repatriated. At this time, we do not intend to repatriate further funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

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

Derivative Positions

At December 31, 2016, we had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold Put ($/bbl)	Purchased Put ($/bbl)	Sold Call ($/bbl)	Premiums received/ (paid) ($/bbl)
Collar: June 1, 2016 to May 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ (1.25)
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ 0.475
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65	$ —

At December 31, 2016, we had outstanding foreign currency derivative positions as follows:

Period and type of instrument	Amount hedged (Millions COP)	Reference	Purchased Call (COP)	Sold Put[1] (COP)	Sold Put[1] (COP)
Collar: January 1, 2017 to March 31, 2017	31,597.6	COP	3,100	3,300	3,345
Collar: April 1, 2017 to May 31, 2017	22,697.2	COP	3,100	3,310	3,370
	54,294.8				

[1] The put levels noted in the table above varied based on market conditions at the inception of each foreign currency derivative contract.

Cash Flows

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

	Year Ended December 31,		
	2016	2015	2014
Sources of cash and cash equivalents:			
Funds flow from continuing operations	**$ 104,984**	$ 107,570	$ 317,184
Proceeds from issuance of Common Stock, net of issuance costs	**128,273**	722	11,140
Proceeds from issuance of subscription receipts, net of issuance costs	**165,805**	—	—
Proceeds from issuance of Notes, net of issuance costs	**109,090**	—	—
Proceeds from other debt, net of issuance costs	**256,065**	—	—
Proceeds from oil and gas properties	**6,000**	—	—
Changes in non-cash investing working capital	**21,116**	—	44,499
Proceeds from sale of marketable securities	**2,325**	—	—
Decrease in restricted cash	**—**	465	—
Foreign exchange gain on cash and cash equivalents	**354**	—	—
Net cash provided by discontinued operations	**—**	—	25,579
	794,012	108,757	398,402
Uses of cash and cash equivalents:			
Acquisitions of PetroLatina and PetroAmerica, net of cash acquired	**(502,643)**	—	—
Additions to property, plant and equipment - acquisition of PGC	**(19,388)**	—	—
Additions to property, plant and equipment, excluding PGC acquisition	**(127,789)**	(156,639)	(391,526)
Repayment of debt	**(252,181)**	—	—
Changes in non-cash investing working capital	**—**	(76,844)	—
Changes in non-cash operating working capital	**(11,337)**	(39,048)	(95,436)
Cash settlement of asset retirement obligation	**(605)**	(6,217)	(796)
Repurchase of shares of Common Stock	**—**	(9,999)	—
Foreign exchange loss on cash and cash equivalents	**—**	(6,516)	(7,500)
Increase in restricted cash	**(236)**	—	(96)
	(914,179)	(295,263)	(495,354)
Net decrease in cash and cash equivalents	**$ (120,167)**	$ (186,506)	$ (96,952)

Cash provided by operating activities in the year ended December 31, 2016, was primarily affected by lower funds flow from operations (see funds flow from operations reconciliation under the heading 'Consolidated Results of Operations' above) and a $11.3 million change in assets and liabilities from operating activities.

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

Off-Balance Sheet Arrangements

As at December 31, 2016, 2015 and 2014 we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2016:

(Thousands of U.S. Dollars)	Total	2017	2018-2019	2020-2021	2021 and beyond
Revolving credit facility	$ 90,000	$ —	$ 90,000	$ —	$ —
5% Convertible Senior Notes due 2021	115,000	—	—	115,000	—
Total long-term debt	205,000	—	90,000	115,000	—
Interest payments[1]	28,989	8,414	13,387	7,188	—
Oil transportation services	13,958	3,639	7,278	3,041	—
Drilling, completions and seismic	4,159	2,172	1,987	—	—
Operating leases	4,111	1,971	1,671	469	—
Software and telecommunication	35	24	11	—	—
Total	$ 256,252	$ 16,220	$ 114,334	$ 125,698	$ —

[1] Interest payments have been calculated utilizing the rates associated with our Notes outstanding at December 31, 2016. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2016, outstanding balance of $90.0 million will be outstanding through the September 2018 maturity date and that our Notes will remain outstanding through their April 2021 maturity date. A constant interest rate of 2.96% was assumed for the interest payments on our revolving credit facility, which was the December 31, 2016 weighted-average interest rate. Actual results will differ from these estimates and assumptions.

At December 31, 2016, we had provided promissory notes totaling $96.8 million to support letters of credit or surety bonds relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements. These unsecured letters of credit do not utilize our revolving credit facility capacity because they are backed by local Colombian banks or insurance companies.

The above table does not reflect estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties and other long-term liabilities, as we cannot determine with accuracy the timing of such payments. Information regarding our asset retirement obligation can be found in Note 10 to the Consolidated Financial Statements, Asset Retirement Obligation, in Item 8 “Financial Statements and Supplementary Data”. The above table also excludes assets and liabilities associated with our derivative contracts, which are dependent on commodity prices or foreign exchange rates at the time of the contract settlement. Information regarding our derivatives can be found in Note 14 to the Consolidated Financial Statements, Asset Retirement Obligation, in Item 8 “Financial Statements and Supplementary Data”.

As is customary in the oil and gas industry, we may at times have commitments in place to reserve or earn certain acreage positions or wells. If we do not meet such commitments, the acreage positions or wells may be lost and associated penalties may be payable.

Critical Accounting Policies and Estimates

The preparation of financial statements under GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as well as the revenues and expenses reported and disclosure of contingent liabilities. Changes in these estimates related to judgments and assumptions will occur as a result of changes in facts and circumstances or discovery of new information, and, accordingly, actual results could differ from amounts estimated.
On a regular basis we evaluate our estimates, judgments and assumptions. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material. The areas of accounting and the associated critical estimates and assumptions made are discussed below.

Full Cost Method of Accounting, Proved Reserves, DD&A and Impairments of Oil and Gas Properties

We follow the full cost method of accounting for our oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 to our annual consolidated financial statements. Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations ("ARO"), and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

Companies that use the full cost method of accounting for oil and natural gas exploration and development activities are required to perform a ceiling test calculation. The ceiling test limits pooled costs to the aggregate of the discounted estimated after-tax future net revenues from proved oil and gas properties, plus the lower of cost or estimated fair value of unproved properties less any associated tax effects.

If our net book value of oil and gas properties, less related deferred income taxes, is in excess of the calculated ceiling, the excess must be written off as an expense. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expenses in future periods. The ceiling limitation is imposed separately for each country in which we have oil and gas properties. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period.

Our estimates of proved oil and gas reserves are a major component of the depletion and full cost ceiling calculations. Additionally, our proved reserves represent the element of these calculations that require the most subjective judgments. Estimates of reserves are forecasts based on engineering data, projected future rates of production and the amount and timing of future expenditures. The process of estimating oil and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. Different reserve engineers may make different estimates of reserve quantities based on the same data.

We believe our assumptions are reasonable based on the information available to us at the time we prepare our estimates. However, these estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change.

Management is responsible for estimating the quantities of proved oil and natural gas reserves and for preparing related disclosures. Estimates and related disclosures are prepared in accordance with SEC requirements and generally accepted industry practices in the United States as prescribed by the Society of Petroleum Engineers. Reserve estimates are evaluated at least annually by independent qualified reserves consultants.

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs, but reflect adjustments for gravity, quality, local conditions, gathering and transportation fees and distance from market. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2016, ceiling tests were based on wellhead prices per BOE as of the first day of each month within that twelve month period of $31.67 for Colombia and $31.42 for Brazil.

Because the ceiling test calculation dictates the use of prices that are not representative of future prices and requires a 10% discount factor, the resulting value should not be construed as the current market value of the estimated oil and gas reserves attributable to our properties. Historical oil and gas prices for any particular 12-month period can be either higher or lower than our price forecast. Therefore, oil and gas property writedowns that result from applying the full cost ceiling limitation, and that are caused by fluctuations in price as opposed to reductions to the underlying quantities of reserves should not be viewed as absolute indicators of a reduction of the ultimate value of the related reserves.

Our Reserves Committee oversees the annual review of our oil and gas reserves and related disclosures. The Board meets with management periodically to review the reserves process, results and related disclosures and appoints and meets with the independent reserves consultants to review the scope of their work, whether they have had access to sufficient information, the nature and satisfactory resolution of any material differences of opinion, and in the case of the independent reserves consultants, their independence.

We assessed our oil and gas properties for impairment as at December 31, 2016, and recorded ceiling test impairment losses of $513.7 million in our Colombia cost center, and $71.1 million in our Brazil cost center, related to lower oil prices and impairment of unproved properties in Brazil. In the year ended December 31, 2016, we also recorded impairment losses in our Peru cost center of $31.2 million, related to costs incurred on Block 95. In the year ended December 31, 2015, we recorded ceiling test impairment losses of $232.4 million in our Colombia cost center, and $46.9 million in our Brazil cost center, related to lower oil prices. In the year ended December 31, 2015, we also recorded impairment losses in our Peru cost center of $41.9

million, related to costs incurred on Block 95. In the year ended December 31, 2014, we recorded an impairment loss of unproved properties in our Peru cost center of $265.1 million due to the lack of continued investment planned for Block 95.

Holding all factors constant other than benchmark oil prices, it is reasonably likely that we will not experience ceiling test impairment losses in our Brazil and Colombia cost centers in the first quarter of 2017.

It is difficult to predict with reasonable certainty the amount of expected future impairment losses given the many factors impacting the asset base and the cash flows used in the prescribed U.S. GAAP ceiling test calculation. These factors include, but are not limited to, future commodity pricing, royalty rates in different pricing environments, operating costs and negotiated savings, foreign exchange rates, capital expenditures timing and negotiated savings, production and its impact on depletion and cost base, upward or downward reserve revisions as a result of ongoing exploration and development activity, and tax attributes. Subject to these factors and inherent limitations, we do not believe that ceiling test impairment losses will be experienced in the first quarter of 2017. The calculation of the impact of higher commodity prices on our estimated ceiling test calculation was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of benchmark oil prices. Therefore, this calculation strictly isolates the impact of commodity prices on the prescribed GAAP ceiling test. This calculation was based on pro forma Brent oil price of $49.54 per bbl for the 12 months ended March 31, 2017. These pro forma oil prices were calculated using a 12-month unweighted arithmetic average of oil prices, and included the oil prices on the first day of the month for the eleven months ended February 2017, and, for the month ended March 2017, estimated oil prices using the forward price curve forecast for the first quarter of 2017 of our independent reserves evaluator dated January 1, 2017.

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

Holding all factors constant other than benchmark oil prices and related royalty rates, we do not expect any downward adjustment to our consolidated NAR reserve volumes during the first quarter of 2017. This disclosure is based on a pro forma Brent oil price of $49.54 per bbl for the 12 months ended March 31, 2017, calculated as described above.

Unproved properties

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. Unproved properties, the costs of which are individually significant, are assessed individually by considering seismic data, plans or requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans and political, economic and market conditions. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, these properties are grouped for purposes of assessing impairment. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to amortization. The transfer of costs into the amortization base involves a significant amount of judgment and may be subject to changes over time based on our drilling plans and results, seismic evaluations, the assignment of proved reserves, availability of capital and other factors. For countries where a reserve base has not yet been established, the impairment is charged to earnings.

Asset Retirement Obligations

We are required to remove or remedy the effect of our activities on the environment at our present and former operating sites by dismantling and removing production facilities and remediating any damage caused. Estimating our future ARO requires us to make estimates and judgments with respect to activities that will occur many years into the future. In addition, the ultimate financial impact of environmental laws and regulations is not always clearly known and cannot be reasonably estimated as standards evolve in the countries in which we operate.

We record ARO in our consolidated financial statements by discounting the present value of the estimated retirement obligations associated with our oil and gas wells and facilities. In arriving at amounts recorded, we make numerous assumptions and judgments with respect to the existence of a legal obligation for an ARO, estimated probabilities, amounts and timing of settlements, inflation factors, credit-adjusted risk-free discount rates and changes in legal, regulatory, environmental and political environments. Because costs typically extend many years into the future, estimating future costs is difficult and requires management to make judgments that are subject to future revisions based upon numerous factors, including changing technology and the political and regulatory environment. In periods subsequent to initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to passage of time impact net income as accretion expense. The related capitalized costs, including revisions thereto, are charged to expense through DD&A. It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results.

Allocation of Consideration Transferred in Business Combinations

The acquisitions of PetroLatina and PetroAmerica in 2016 was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recorded at their fair values at the acquisition date. For the PetroAmerica acquisition, the excess of the fair values of the net assets acquired over the consideration transferred recorded as a gain on acquisition. For the PetroLatina acquisition, the fair value of the consideration transferred was equal to the fair value of the net assets acquired and no gain or goodwill was recorded on acquisition. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, was subject to estimates which include various assumptions including the fair value of proved and unproved reserves of the assets acquired as well as future production and development costs and future oil and gas prices.

While these estimates of fair value for the various assets acquired and liabilities assumed have no effect on our liquidity or capital resources, they can have an effect on the future results of operations. Generally, the higher the fair value assigned to both oil and gas properties and non-oil and gas properties, the lower future net income will be as a result of higher future DD&A expenses. Also, a higher fair value assigned to the oil and gas properties, based on higher future estimates of oil and gas prices, will increase the likelihood of a full cost ceiling write down in the event that future oil and gas prices drop below the price forecast used to originally determine fair value.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over net identifiable assets acquired and liabilities assumed. The goodwill on our balance sheet resulted from the Solana Resources Limited and Argosy Energy International L.P. acquisitions, in 2008 and 2006 respectively, and relates entirely to the Colombia reporting unit.

At each reporting date, we assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. Changes in our future cash flows, operating results, growth rates, capital expenditures, cost of capital, discount rates, stock price or related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

The two-step goodwill impairment test would require a comparison of the fair value of each reporting unit to the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, we would write down the goodwill to the implied fair value of the goodwill through a charge to expense. The most significant judgments involved in estimating the fair values of our reporting units would relate to the valuation of our property and equipment. A lower goodwill value decreases the likelihood of an impairment charge. Unfavorable changes in reserves or in our price forecast would increase the likelihood of a goodwill impairment charge. A goodwill impairment charge would have no effect on liquidity or capital resources. However, it would adversely affect our results of operations in that period.

At December 31, 2016, we performed a qualitative assessment of goodwill and, based on this assessment, no impairment of goodwill was identified. Ceiling test impairment losses in our Colombian cost center of $513.7 million net of the associated deferred tax recovery of $201.3 million reduced the carrying value of the reporting unit in 2016 by $312.4 million. Additionally, forward curve oil prices as at December 31, 2016, were higher than those used in the ceiling test impairment calculation. This reduction in carrying value combined with increased reserves and forward curve oil prices as at December 31, 2016, resulted in no impairment of goodwill.

Income Taxes

We follow the liability method of accounting for income taxes whereby we recognize deferred income tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax bases. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of existing tax net operating loss carryforwards and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

We carry on business in several countries and as a result, we are subject to income taxes in numerous jurisdictions. The determination of our income tax provision is inherently complex and we are required to interpret continually changing regulations and make certain judgments. While income tax filings are subject to audits and reassessments, we believe we have made adequate provision for all income tax obligations. However, changes in facts and circumstances as a result of income tax audits, reassessments, jurisprudence and any new legislation may result in an increase or decrease in our provision for income taxes.

To assess the realization of deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. We consider the scheduled reversal of deferred tax liabilities, projected future taxable income and tax planning strategies in making this assessment.

Our effective tax rate is based on pre-tax income and the tax rates applicable to that income in the various jurisdictions in which we operate. An estimated effective tax rate for the year is applied to our quarterly operating results. In the event that there is a significant unusual or discrete item recognized, or expected to be recognized, in our quarterly operating results, the tax attributable to that item would be separately calculated and recorded at the same time as the unusual or discrete item. We consider the resolution of prior-year tax matters to be such items. Significant judgment is required in determining our effective tax rate and in evaluating our tax positions. We establish reserves when it is more likely than not that we will not realize the full tax benefit of the position. We adjust these reserves in light of changing facts and circumstances.

We routinely assess potential uncertain tax positions and, if required, estimate and establish accruals for such amounts.

Legal and Other Contingencies

A provision for legal and other contingencies is charged to expense when the loss is probable and the cost can be reasonably estimated. Determining when expenses should be recorded for these contingencies and the appropriate amounts for accrual is a complex estimation process that includes the subjective judgment of management. In many cases, management’s judgment is based on interpretation of laws and regulations, which can be interpreted differently by regulators and/or courts of law. Management closely monitors known and potential legal and other contingencies and periodically determines when we should record losses for these items based on information available to us.

Stock-Based Compensation

Our stock-based compensation cost is measured based on the fair value of the awards that are ultimately expected to vest. Fair values are determined using pricing models such as the Black-Scholes-Merton or Monte Carlo simulation stock option-pricing models and/or observable share prices. These estimates depend on certain assumptions, including volatility, risk-free interest rate, the term of the awards and the forfeiture rate, which, by their nature, are subject to measurement uncertainty. We use historical data to estimate the expected term used in the Black-Scholes option pricing model, option exercises and employee departure behavior. Expected volatilities used in the fair value estimate are based on the historical volatility of our shares. The risk-free rate for periods within the expected term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant.

New Accounting Pronouncements

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

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

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU is not expected to have a material impact on our consolidated financial position, results of operations or cash flows or disclosure.

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

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting". This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. We are currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses". This ASU replaces the current incurred loss impairment methodology with a methodology that reflects expected credit losses and requires a broader range of reasonable and supportable information to support credit loss estimates. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2019. We are currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

In October 2016, the FASB issued ASU 2016-16, "Intra-Entity Transfers of Assets Other than Inventory". This ASU requires companies to recognize the income tax effects of intercompany sales or transfers of assets, other than inventory, in the income statement as income tax expense (or benefit) in the period the sale or transfer occurs. Current GAAP prohibits the recognition of current and deferred income taxes for an intra-entity transfer until the asset leaves the consolidated group.

This ASU will be effective for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption is permitted as of the beginning of an annual reporting period. The ASU must be applied on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings in the period of adoption. In the period of adoption, we will write off any income tax effects that had been deferred from past intercompany transactions to opening retained earnings.

We expect to early adopt this ASU in our year ended December 31, 2017, and expect prepaid tax of $54.1 million and deferred tax assets will be recorded directly to opening retained earnings at January 1, 2017. We are currently assessing the deferred tax effect of adoption of the ASU. Deferred tax assets recorded upon adoption will be assessed for realizability under ASC 740, and, if a valuation allowance on those deferred tax assets is necessary on the date of adoption, that allowance will be recorded with an offset to opening retained earnings. ASU 2016-16 will not have any effect on our cash flows.

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash". ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU will not impact our consolidated financial position or results of operations and for the year ended December 31, 2016, would not have had a material impact on net cash used in investing activities. For the year ended December 31, 2016, the net decrease in cash, cash equivalents and restricted cash and cash equivalents would have been $119.9 million, compared with the net decrease in cash and cash equivalents of $120.2 million, as currently disclosed in the consolidated statement of cash flows.

In January 2017, the FASB issued ASU 2017-01, "Clarifying the Definition of a Business". ASU 2017-01 narrows the definition of a business and provides a framework that gives entities a basis for making reasonable judgments about whether a transaction involves an asset or a business. ASU 2017-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption is permitted. We expect to early adopt this ASU in the year ended December 31, 2017. We will apply an initial screen for determining whether a transaction involves an asset or a business. When substantially all of the fair value of the gross assets acquired is concentrated in a single identified asset, the set will not be a business and no goodwill or gain on acquisition will be recognized.

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

Business Environment Outlook

For over 40 years, the Colombian government has been engaged in a conflict with two main Marxist guerrilla groups: 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 was organized to combat FARC and ELN, but has since been dissolved by the Columbian government. We operate principally in the Putumayo Basin in Colombia. Pipelines have been primary targets because of the length of such pipelines and the remoteness of the areas in which the pipelines are laid. The OTA pipeline which transports oil from the Putumayo region and which is one of our export routes has been targeted by these guerrilla groups.

On September 26, 2016, the Colombian government and the Revolutionary Armed Forces of Colombia ("FARC") signed a peace agreement and, on November 30, 2016, the Agreement was ratified by Colombia's government. Pursuant to the Peace Agreement, the FARC agreed to demobilize its troops and urban militia members and to hand over its weapons to a United Nations mission within 180 days. Once demobilized and disarmed, the FARC can become a legal political party. Under the Peace Agreement, the FARC will be guaranteed at least five seats in the Senate and another five seats in the House of Representatives in 2018 congressional elections, even if they don't get enough votes for those seats. Continuing attempts by the Colombian government to reduce or prevent activity of guerrilla dissidents may not be successful and such activity may continue to disrupt our operations in the future.

The Colombian government is also engaged in a conflict with another Marxist guerrilla group, the National Liberation Army ("ELN"). The ELN has stated that it wants to negotiate a peace agreement, however, peace process negotiations may not generate the intended outcome for both parties. The impact of such a peace process is not determinable on our operations. This group has been designated as a terrorist organization by the United States and the European Union. Another threat comes from criminal gangs formed from the former members of the United Self-Defense Forces of Colombia militia, a paramilitary group that originally sprouted up to combat FARC and ELN, which the Colombian government successfully dissolved. We operate principally in the Putumayo Basin in Colombia. Pipelines have been primary targets because such pipelines cannot be adequately secured due to the sheer length of such pipelines and the remoteness of the areas in which the pipelines are laid. The CENIT S.A-operated Trans-Andean oil pipeline (the "OTA pipeline") which transports oil from the Putumayo region and which is one of our export routes, has been targeted by these guerrilla groups.

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 revenues are significantly affected by the continuing fluctuations in world oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about the quantity of world supply and demand fundamentals, market competition between large producers, predominately members of OPEC (Organization of Petroleum Producing Countries), for market share, political influences, financial markets and the impact of the worldwide economy on oil supply and demand growth.

We expect to finance our 2017 capital program through cash flows from operations and available capacity under our credit facility, while retaining financial flexibility to undertake further development opportunities and opportunistically pursue acquisitions. Should our operating cash flow decline due to unforeseen events, including additional pipeline delivery restrictions in Colombia or continued downturn in oil and gas prices, we would consider financing our capital expenditure program with proceeds from the disposition of assets or capital markets transactions, or a combination thereof, or we would consider reducing our capital expenditure program. We are the operator in the majority of our blocks and therefore have discretion on the timing of our capital expenditures. Given the current economic environment and unstable conditions in the Middle East, North Africa, and Europe and the current over supply of oil in world markets, the oil price environment is unpredictable and unstable. We are unable to determine the impact, if any, these events may have on oil prices and demand. The timing and execution of our capital expenditure program are also affected by the availability of services from third party oil field contractors and our ability to obtain, sustain or renew necessary government licenses and permits on a timely basis to conduct exploration and development activities. Any delay may affect our ability to execute our capital expenditure program.

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

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

Item 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Commodity price risk

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

During the year ended December 31, 2016, we entered into commodity price derivative contracts to manage the variability cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending. The table below provides information about our commodity price derivative contracts at December 31, 2016, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. We do not hold any of these investments for trading purposes. At December 31, 2015, we did not have any open commodity price derivative positions.

Period and type of instrument	Volume, bopd	Reference	Sold Put ($/bbl)	Purchased Put ($/bbl)	Sold Call ($/bbl)	Premiums received/ (paid) ($/bbl)
Collar: June 1, 2016 to May 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ (1.25)
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ 0.475
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65	$ —

Foreign currency risk

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

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $43,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

During the year ended December 31, 2016, we entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs. The table below provides information about our foreign currency forward exchange agreements at December 31, 2016, including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. We do not hold any of these investments for trading purposes. At December 31, 2015, we did not have any open foreign currency derivative positions.

Period and type of instrument	Amount hedged (Millions COP)	Reference	Purchased Call (COP)	Sold Put[1] (COP)	Sold Put[1] (COP)
Collar: January 1, 2017 to March 31, 2017	31,597.6	COP	3,100	3,300	3,345
Collar: April 1, 2017 to May 31, 2017	22,697.2	COP	3,100	3,310	3,370
	54,294.8				

[1] The put levels noted in the table above varied based on market conditions at the inception of each foreign currency derivative contract.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. We are exposed to interest rate fluctuations on our revolving credit facility, which bears floating rates of interest. At December, 2016, our outstanding revolving credit facility was $90.0 million (December 31, 2015 - nil), which had a weighted-average interest rate of approximately 2.96%. A 10% change in LIBOR would not materially impact our interest expense on debt outstanding at December 31, 2016.

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.

Item 8. ***Financial Statements and Supplementary Data***

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Gran Tierra Energy Inc.

We have audited the accompanying consolidated balance sheets of Gran Tierra Energy Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015, and the related consolidated statements of operations, cash flows and shareholders' equity for each of the three years in the period ended December 31, 2016. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States) and Canadian generally accepted auditing standards. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and subsidiaries as of December 31, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2017 expressed an unqualified opinion on the Company’s internal control over financial reporting.

/s/ Deloitte LLP

Chartered Professional Accountants
February 28, 2017
Calgary, Canada

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

	Year Ended December 31,		
	2016	**2015**	**2014**
OIL AND NATURAL GAS SALES (NOTE 5)	**$ 289,269**	$ 276,011	$ 559,398
EXPENSES			
Operating	**86,925**	75,565	89,753
Transportation	**31,776**	40,204	24,196
Depletion, depreciation and accretion (Note 5)	**139,535**	176,386	185,877
Asset impairment (Notes 5 and 7)	**616,649**	323,918	265,126
General and administrative (Note 5)	**33,218**	32,353	51,249
Transaction (Note 3)	**7,325**	—	—
Severance (Note 15)	**1,319**	8,990	—
Equity tax (Note 11)	**3,098**	3,769	—
Foreign exchange gain	**(1,469)**	(17,242)	(39,535)
Financial instruments loss (Note 14)	**10,279**	2,027	4,722
Other gain (Note 3)	**(929)**	(502)	(2,000)
Interest expense (Notes 5 and 8)	**14,145**	—	—
	941,871	645,468	579,388
INTEREST INCOME (NOTE 5)	**2,368**	1,369	2,856
LOSS FROM CONTINUING OPERATIONS BEFORE INCOME TAXES (NOTE 5)	**(650,234)**	(368,088)	(17,134)
INCOME TAX (EXPENSE) RECOVERY			
Current (Note 11)	**(20,122)**	(15,383)	(92,865)
Deferred (Note 11)	**204,791**	115,442	(34,350)
	184,669	100,059	(127,215)
LOSS FROM CONTINUING OPERATIONS	**(465,565)**	(268,029)	(144,349)
Loss from discontinued operations, net of income taxes (Note 4)	**—**	—	(26,990)
NET LOSS AND COMPREHENSIVE LOSS	**$ (465,565)**	$ (268,029)	$ (171,339)
NET LOSS PER SHARE - BASIC AND DILUTED			
BASIC AND DILUTED			
LOSS FROM CONTINUING OPERATIONS	**$ (1.45)**	$ (0.94)	$ (0.51)
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	**—**	—	(0.09)
NET LOSS	**$ (1.45)**	$ (0.94)	$ (0.60)
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC AND DILUTED (Note 9)	***320,851,538***	*285,333,869*	*284,715,785*

(See notes to the consolidated financial statements)

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

	As at December 31, 2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 25,175**	$ 145,342
Restricted cash and cash equivalents (Notes 3, 7 and 10)	**8,322**	92
Accounts receivable (Note 6)	**45,698**	29,217
Marketable securities (Note 14)	**—**	6,250
Derivatives (Note 14)	**578**	—
Inventory (Note 6)	**7,766**	19,056
Taxes receivable	**26,393**	28,635
Prepaid taxes (Note 11)	**12,271**	—
Other prepaids	**5,482**	5,848
Total Current Assets	**131,685**	234,440
Oil and Gas Properties (using the full cost method of accounting)		
Proved	**412,319**	469,589
Unproved	**647,774**	310,771
Total Oil and Gas Properties	**1,060,093**	780,360
Other capital assets	**6,516**	8,633
Total Property, Plant and Equipment (Notes 5 and 7)	**1,066,609**	788,993
Other Long-Term Assets		
Deferred tax assets (Note 11)	**1,611**	3,241
Prepaid taxes (Note 11)	**41,784**	—
Other long-term assets	**23,626**	16,863
Goodwill (Note 5)	**102,581**	102,581
Total Other Long-Term Assets	**169,602**	122,685
Total Assets (Note 5)	**$ 1,367,896**	$ 1,146,118
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 12)	**$ 107,051**	$ 70,778
Derivatives (Note 14)	**3,824**	—
Taxes payable (Note 11)	**38,939**	1,067
Asset retirement obligation (Note 10)	**5,215**	2,146
Total Current Liabilities	**155,029**	73,991
Long-Term Liabilities		
Long-term debt (Notes 8 and 14)	**197,083**	—
Deferred tax liabilities (Note 11)	**107,230**	34,592
Asset retirement obligation (Note 10)	**38,142**	31,078
Other long-term liabilities	**11,425**	4,815
Total Long-Term Liabilities	**353,880**	70,485
Commitments and Contingencies (Note 13)		
Subsequent Events (Note 17)		
Shareholders' Equity		
Common Stock (Note 9) (390,807,194 and 273,442,799 shares of Common Stock and 8,199,894 and 8,572,066 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2016 and December 31, 2015, respectively)	**10,303**	10,186
Additional paid in capital	**1,342,656**	1,019,863
Deficit	**(493,972)**	(28,407)
Total Shareholders' Equity	**858,987**	1,001,642
Total Liabilities and Shareholders' Equity	**$ 1,367,896**	$ 1,146,118

(See notes to the consolidated financial statements)

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

	Year Ended December 31,		
	2016	**2015**	**2014**
Operating Activities			
Net loss	**$ (465,565)**	$ (268,029)	$ (171,339)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depletion, depreciation and accretion (Note 5)	**139,535**	176,386	185,877
Asset impairment (Notes 5 and 7)	**616,649**	323,918	265,126
Deferred tax (recovery) expense (Note 11)	**(204,791)**	(115,442)	34,350
Stock-based compensation (Note 9)	**6,339**	2,733	6,392
Amortization of debt issuance costs (Note 8)	**5,691**	—	—
Cash settlement of restricted share units	**(1,234)**	(1,392)	(3,371)
Unrealized foreign exchange gain	**(1,428)**	(8,380)	(30,941)
Financial instruments loss (Note 14)	**10,279**	2,027	4,722
Cash settlement of financial instruments	**438**	(3,749)	4,661
Cash settlement of asset retirement obligation (Note 10)	**(605)**	(6,217)	(796)
Other gain (Note 3)	**(929)**	(502)	(2,000)
Equity tax	**—**	—	(3,283)
Loss from discontinued operations, net of income taxes (Note 4)	**—**	—	26,990
Net change in assets and liabilities from operating activities of continuing operations (Note 16)	**(11,337)**	(39,048)	(95,436)
Net cash provided by operating activities of continuing operations	**93,042**	62,305	220,952
Net cash used in operating activities of discontinued operations	**—**	—	(4,792)
Net cash provided by operating activities	**93,042**	62,305	216,160
Investing Activities			
(Increase) decrease in restricted cash	**(236)**	465	(96)
Additions to property, plant and equipment, excluding corporate acquisition (Note 5)	**(127,789)**	(156,639)	(391,526)
Additions to property, plant and equipment - acquisition of PetroGranada (Note 7)	**(19,388)**	—	—
Cash paid for business combinations, net of cash acquired (Note 3)	**(502,643)**	—	—
Proceeds from the sale of oil and gas properties (Note 7)	**6,000**	—	—
Proceeds from sale of marketable securities (Note 14)	**2,325**	—	—
Changes in non-cash investing working capital	**21,116**	(76,844)	44,499
Net cash used in investing activities of continuing operations	**(620,615)**	(233,018)	(347,123)
Proceeds from sale of Argentina business unit, net of cash sold and transaction costs	**—**	—	42,755
Net cash used in investing activities of discontinued operations	**—**	—	(12,384)
Net cash provided by investing activities of discontinued operations	**—**	—	30,371
Net cash used in investing activities	**(620,615)**	(233,018)	(316,752)
Financing Activities			
Proceeds from issuance of shares of Common Stock, net of issuance costs (Note 9)	**128,273**	722	11,140
Proceeds from issuance of subscription receipts, net of issuance costs (Note 9)	**165,805**	—	—
Proceeds from issuance of Convertible Senior Notes, net of issuance costs (Note 8)	**109,090**	—	—
Proceeds from other debt, net of issuance costs (Note 8)	**256,065**	—	—
Repayment of debt (Note 8)	**(252,181)**	—	—
Repurchase of shares of Common Stock (Note 9)	**—**	(9,999)	—
Net cash provided by (used in) financing activities	**407,052**	(9,277)	11,140
Foreign exchange gain (loss) on cash and cash equivalents	**354**	(6,516)	(7,500)

Net decrease in cash and cash equivalents	**(120,167)**	(186,506)	(96,952)
Cash and cash equivalents, beginning of year	**145,342**	331,848	428,800
Cash and cash equivalents, end of year	**$ 25,175**	$ 145,342	$ 331,848

Supplemental cash flow disclosures (Note 16)

(See notes to the consolidated financial statements)

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

	Year Ended December 31,		
	2016	**2015**	**2014**
Share Capital			
Balance, beginning of year	**$ 10,186**	$ 10,190	$ 10,187
Issuance of Common Stock (Note 9)	**117**	—	3
Repurchase of Common Stock (Note 9)	**—**	(4)	—
Balance, end of year	**10,303**	10,186	10,190
Additional Paid in Capital			
Balance, beginning of year	**1,019,863**	1,026,873	1,008,760
Issuance of Common Stock, net of share issuance costs (Note 9)	**314,425**	—	—
Exercise of stock options (Note 9)	**5,347**	722	11,137
Stock-based compensation (Note 9)	**3,021**	2,263	6,976
Repurchase of Common Stock (Note 9)	**—**	(9,995)	—
Balance, end of year	**1,342,656**	1,019,863	1,026,873
Retained Earnings (Deficit)			
Balance, beginning of year	**(28,407)**	239,622	410,961
Net loss	**(465,565)**	(268,029)	(171,339)
Balance, end of year	**(493,972)**	(28,407)	239,622
Total Shareholders' Equity	**$ 858,987**	$ 1,001,642	$ 1,276,685

(See notes to the consolidated financial statements)

1. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the “Company” or “Gran Tierra”), is a publicly traded company focused on oil and natural gas exploration and production in Colombia. The Company also has business activities in Peru and Brazil, and until June 25, 2014, had business activities in Argentina. On February, 6, 2017, the Company announced that a purchase and sale agreement (the "Agreement") had been executed by a third party ("Purchaser") to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (Note 17).

2. Significant Accounting Policies

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America (“GAAP”). The Company believes that the information and disclosures presented are adequate to ensure the information presented is not misleading.

Significant accounting policies are:

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its controlled subsidiaries. All intercompany accounts and transactions have been eliminated.

Discontinued operations

On June 25, 2014, the Company completed the sale of its Argentina business unit and the discontinued operations criteria of Accounting Standards Codification ("ASC") 205-20, “*Discontinued Operations*”, were met. Therefore, the results of the Company’s Argentina business unit are reflected separately as loss from discontinued operations, net of income taxes, in the consolidated statement of operations for the year ended December 31, 2014, on a line immediately after “Loss or income from continuing operations.” Additionally, cash flows of the Company’s Argentina business unit are reflected separately in the consolidated statement of cash flows for the year ended December 31, 2014, as cash provided by or used in operating and investing activities of discontinued operations. See Note 4, “Discontinued Operations,” for additional disclosure.

Use of estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates made by management include: oil and natural gas reserves and related present value of future cash flows; depreciation, depletion, amortization and impairment (“DD&A”); impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to depletion to the depletable base; asset retirement obligations; determining the value of the consideration transferred and the net identifiable assets acquired and liabilities assumed in connection with business combinations and determining goodwill; assessments of the likely outcome of legal and other contingencies; income taxes; stock-based compensation; and determining the fair value of derivatives. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates and actual results may differ from these estimates.

Cash and cash equivalents

The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents.

Restricted cash and cash equivalents

Restricted cash and cash equivalents is included in other current assets and other long-term assets on the Company's balance sheet. Restricted cash and cash equivalents comprises cash and cash equivalents pledged to secure letters of credit and to settle asset retirement obligations. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. Restrictions will lapse when work obligations are satisfied pursuant to the exploration contract or an asset retirement obligation is settled. Cash and claims to cash that are restricted as to withdrawal or use for other than current operations or are designated for expenditure in the acquisition or construction of long-term assets are excluded from the current asset classification.

Allowance for doubtful accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred and accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of the reserve may be reasonably estimated. The allowance for doubtful receivables was $nil at December 31, 2016, and 2015.

Marketable securities

The Company acquired investments in marketable securities in connection with the sale of its Argentina business unit in 2014. Marketable securities are classified as trading securities, in accordance with ASC 320, "*Investments – Debt and Equity Securities*", and are recorded in the consolidated balance sheet at fair value. The Company classifies trading securities as current or non-current based on the intent of management, the nature of the trading securities and whether they are readily available for use in current operations. Gains or losses on trading securities are recorded in the consolidated statement of operations as financial instruments gains or losses.

Derivatives

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

Inventory

Inventory consists of oil in tanks and third party pipelines and supplies and is valued at the lower of cost or market value. The cost of inventory is determined using the weighted average method. Oil inventories include expenditures incurred to produce, upgrade and transport the product to the storage facilities and include operating, depletion and depreciation expenses and cash royalties.

Income taxes

Income taxes are recognized using the liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the consolidated financial statement carrying amounts of existing assets and liabilities and their respective tax base, and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. Valuation allowances are provided if, after considering available evidence, it is not more likely than not that some or all of the deferred tax assets will be realized.

The tax benefit from an uncertain tax position is recognized when it is more likely than not, based on the technical merits of the position, that the position will be sustained on examination by the taxing authorities. Additionally, the amount of the tax benefit recognized is the largest amount of benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. In evaluating whether a tax position has met the more-likely-than-not recognition threshold, the Company presumes that the position will be examined by the appropriate taxing authority that has full knowledge of all relevant information. The Company recognizes potential penalties and interest related to unrecognized tax benefits as a component of income tax expense.

Oil and gas properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties as defined by the Securities and Exchange Commission ("SEC"). Under this method, the Company capitalizes all acquisition, exploration and development costs incurred for the purpose of finding oil and natural gas reserves, including salaries, benefits and other internal costs directly attributable to these activities. Costs associated with production and general corporate activities; however, are expensed as incurred. Separate cost centers are maintained for each country in which the Company incurs costs.

The Company computes depletion of oil and natural gas properties on a quarterly basis using the unit-of-production method based upon production and estimates of proved reserve quantities. Future development costs related to properties with proved reserves are also included in the amortization base for computation of depletion. The costs of unproved properties are excluded from the amortization base until the properties are evaluated. The cost of exploratory dry wells is transferred to proved properties, and thus is subject to amortization, immediately upon determination that a well is dry in those countries where proved reserves exist.

The Company performs a ceiling test calculation each quarter in accordance with SEC Regulation S-X Rule 4-10. In performing its quarterly ceiling test, the Company limits, on a country-by-country basis, the capitalized costs of proved oil and natural gas properties, net of accumulated depletion and deferred income taxes, to the estimated future net cash flows from proved oil and natural gas reserves discounted at 10%, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the costs being amortized. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to net income or loss. Any such write-down will reduce earnings in the period of occurrence and results in a lower DD&A rate in future periods. A write-down may not be reversed in future periods even though higher oil and natural gas prices may subsequently increase the ceiling.

The Company calculates future net cash flows by applying the unweighted average of prices in effect on the first day of the month for the preceding 12-month period, adjusted for location and quality differentials. Such prices are utilized except where different prices are fixed and determinable from applicable contracts for the remaining term of those contracts.

Unproved properties are not depleted pending the determination of the existence of proved reserves. Costs are transferred into the depletable base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. Unproved properties are evaluated quarterly to ascertain whether impairment has occurred. This evaluation considers, among other factors, seismic data, requirements to relinquish acreage, drilling results and activity, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions. During any period in which factors indicate an impairment, the cumulative costs incurred to date for such property are transferred to the full cost pool and are then subject to depletion. For countries where a reserve base has not yet been established, the impairment is charged to earnings.

In exploration areas, related seismic costs are capitalized in unproved property and evaluated as part of the total capitalized costs associated with a property. Seismic costs related to development projects are recorded in proved properties and therefore subject to depletion as incurred.

Gains and losses on the sale or other disposition of oil and natural gas properties are not recognized, unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and natural gas attributable to a country.

Asset retirement obligation

The Company records an estimated liability for future costs associated with the abandonment of its oil and gas properties including the costs of reclamation of drilling sites. The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to the related oil and gas properties. 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. 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. The accretion of the asset retirement obligation and amortization of the asset retirement cost are included in DD&A. If estimated future costs of an asset retirement obligation change, an adjustment is recorded to both the asset retirement obligation and oil and gas properties. Revisions to the estimated asset retirement obligation can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Other capital assets

Other capital assets, including additions and replacements, are recorded at cost upon acquisition and include furniture, fixtures and leasehold improvement, computer equipment and automobiles. Depreciation is provided using the declining-balance method at a 30% annual rate for furniture and fixtures, computer equipment and automobiles. Leasehold improvements are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expense as incurred.

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed. The Company assesses qualitative factors annually, or more frequently if necessary, to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. The impairment test requires allocating goodwill and certain other assets and liabilities to assigned reporting units. The fair value of each reporting unit is estimated and compared with the net book value of the reporting unit. If the estimated fair value of the reporting unit is less than the net book value, including goodwill, then the goodwill is written down to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for the Company's reporting units, the fair values of the reporting units are estimated based upon estimated future cash flows of the reporting unit.

The Company recorded $87.6 million of goodwill in relation to the acquisition of Solana Resources Limited ("Solana") in 2008 and $15.0 million of goodwill in relation to the Argosy Energy International L.P. acquisition in 2006. The goodwill relates entirely to the Colombia reportable segment. The Company performed a qualitative assessment of goodwill at December 31, 2016, and based on this assessment, no impairment of goodwill was identified.

Convertible Senior Notes

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

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

Revenue recognition

Revenue from the production of oil and natural gas is recognized when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable, the sale is evidenced by a contract and collection of the revenue is reasonably assured. In Colombia, the sales point for the Company's sales varies depending on the delivery point but includes the Port of Tumaco on the Pacific coast of Colombia, the purchaser's facilities and when oil is loaded into a truck at Gran Tierra's loading facility or an export tanker. In Brazil, the sales point is either the Petróleo Brasileiro S.A station or the purchaser's facility.

Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company records stock-based compensation expense in its consolidated financial statements measured at the fair value of the awards that are ultimately expected to vest. Fair values are determined using pricing models such as the Black-Scholes-Merton or Monte Carlo simulation stock option-pricing models and/or observable share prices. For equity-settled stock-based compensation awards, fair values are determined at the grant date and the expense, net of estimated forfeitures, is recognized using the accelerated method over the requisite service period. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures. For cash-settled stock-based compensation awards, fair values are determined at each reporting date and periodic changes are recognized as compensation costs, with a corresponding change to liabilities.

The Company uses historical data to estimate the expected term used in the Black-Scholes option pricing model, option exercises and employee departure behavior. Expected volatilities used in the fair value estimate are based on the historical volatility of the Company's shares. The risk-free rate for periods within the expected term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant.

Stock-based compensation expense is capitalized as part of oil and natural gas properties or expensed as part of general and administrative ("G&A") or operating expenses, as appropriate.

Foreign currency translation

The functional currency of the Company, including its subsidiaries, is the United States dollar. Monetary items are translated into the reporting currency at the exchange rate in effect at the balance sheet date and non-monetary items are translated at historical exchange rates. Revenue and expense items are translated in a manner that produces substantially the same reporting currency amounts that would have resulted had the underlying transactions been translated on the dates they occurred.

DD&A expense on assets is translated at the historical exchange rates similar to the assets to which they relate. Gains and losses resulting from foreign currency transactions, which are transactions denominated in a currency other than the entity's functional currency, are recognized in net income or loss.

Loss per share

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

Recently Adopted Accounting Pronouncements

Simplifying the Accounting for Measurement - Period Adjustments

In September 2015, the Financial Accounting Standards Board (the "FASB") issued Accounting Standards Update ("ASU") 2015-16, "Simplifying the Accounting for Measurement - Period Adjustments". The amendments require that an acquirer recognize adjustments to provisional amounts identified during the measurement period in the reporting period in which the adjustments are determined and eliminates the requirement to retrospectively revise prior periods. Additionally, an acquirer should record in the same period the effects on earnings of any changes in the provisional accounts, calculated as if the accounting had been completed at the acquisition date. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The implementation of this update did not materially impact the Company's consolidated financial position at December 31, 2016 or results of operations or cash flows for the year ended December 31, 2016. See Note 3, "Business Combinations," for additional disclosure.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued ASU 2016-15, "Classification of Certain Cash Receipts and Cash Payments". This ASU addresses specific cash flow issues with the objective of reducing the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017. The Company implemented this update retrospectively in its consolidated financial statements for the interim period ended September 30, 2016. The implementation of this update did not materially impact the Company's consolidated financial position, results of operations or cash flows or disclosure.

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued guidance regarding the accounting for revenue from contracts with customers. In August 2015, the FASB issued ASU 2015-14, "Revenue from Contracts with Customers - Deferral of the Effective Date". The ASU deferred the effective date of the new revenue recognition model by one year. As a result, the guidance will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2017.

In March 2016, the FASB issued ASU 2016-08, "Principal versus Agent Considerations (Reporting Revenue Gross versus Net)" which clarifies implementation guidance on principal versus agent considerations. In April, May and December 2016, the FASB issued ASU 2016-10, "Identifying Performance Obligations and Licensing", ASU 2016-12, "Narrow-Scope Improvements and Practical Expedients" and ASU 2016-20 "Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers", respectively, which addressed implementation issues and provided technical corrections.

The guidance may be applied retrospectively or using a modified retrospective approach to adjust retained earnings. The Company is currently assessing the impact the new revenue recognition model will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Simplifying the Measurement of Inventory

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

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU 2016-01, "Recognition and Measurement of Financial Assets and Financial Liabilities". ASU 2016-01 addresses certain aspects of recognition, measurement, presentation and disclosure of financial instruments. ASU 2016-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows or disclosure.

Leases

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

Employee Share-Based Payment Accounting

In March 2016, the FASB issued ASU 2016-09, "Improvements to Employee Share-Based Payment Accounting". This ASU simplifies several aspects of the accounting for employee share-based payment transactions, including the accounting for forfeitures, income taxes, and statutory tax withholding requirements. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. The Company is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

Financial Instruments - Credit Losses

In June 2016, the FASB issued ASU 2016-13, "Financial Instruments - Credit Losses". This ASU replaces the current incurred loss impairment methodology with a methodology that reflects expected credit losses and requires a broader range of reasonable and supportable information to support credit loss estimates. The ASU will be effective for fiscal years, and interim periods within those years, beginning after December 15, 2019. The Company is currently assessing the impact this update will have on its consolidated financial position, results of operations, cash flows, and disclosure.

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

In October 2016, the FASB issued ASU 2016-16, "Intra-Entity Transfers of Assets Other than Inventory". This ASU requires companies to recognize the income tax effects of intercompany sales or transfers of assets, other than inventory, in the income statement as income tax expense or benefit in the period the sale or transfer occurs. Current GAAP prohibits the recognition of income tax expense or benefit for an intra-entity transfer until the asset leaves the consolidated group.

This ASU will be effective for fiscal years beginning after December 15, 2017, and interim periods within those years. Early adoption is permitted as of the beginning of an annual reporting period. The ASU must be applied on a modified retrospective basis with a cumulative-effect adjustment directly to retained earnings in the period of adoption. In the period of adoption, the Company will write off any income tax effects that had been deferred from past intercompany transactions to opening retained earnings.

The Company expects to early adopt this ASU in its year ended December 31, 2017, and expects prepaid tax of $54.1 million and deferred tax assets will be recorded directly to opening retained earnings at January 1, 2017. The Company is currently assessing the deferred tax effect of adoption of this ASU. Deferred tax assets recorded upon adoption will be assessed for realizability under ASC 740, and, if a valuation allowance on those deferred tax assets is necessary on the date of adoption, that allowance will be recorded with an offset to opening retained earnings. ASU 2016-16 will not have any effect on the Company's cash flows.

Restricted Cash

In November 2016, the FASB issued ASU 2016-18, "Restricted Cash". ASU 2016-18 requires that a statement of cash flows explain the change during the period in the total cash, cash equivalents and amounts generally described as restricted cash or restricted cash equivalents. ASU 2016-18 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. This ASU will not impact the Company's consolidated financial position or results of operations and for the year ended December 31, 2016, would not have had a material impact on net cash used in investing activities. For the year ended December 31, 2016, the net decrease in cash, cash equivalents and restricted cash and cash equivalents would have been $119.9 million, compared with the net decrease in cash and cash equivalents of -$120.2 million as currently disclosed in the consolidated statement of cash flows.

Clarifying the Definition of a Business

In January 2017, the FASB issued ASU 2017-01, "Clarifying the Definition of a Business". ASU 2017-01 narrows the definition of a business and provides a framework that gives entities a basis for making reasonable judgments about whether a transaction involves an asset or a business. ASU 2017-01 is effective for annual reporting periods and interim reporting periods within those annual reporting periods, beginning after December 15, 2017. Early adoption is permitted.

The Company expects to early adopt this ASU in its year ended December 31, 2017. The Company will apply an initial screen for determining whether a transaction involves an asset or a business. When substantially all of the fair value of the gross assets acquired is concentrated in a single identified asset, the set will not be a business and no goodwill or gain on acquisition will be recognized.

Simplifying the Test for Goodwill Impairment

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

3. Business Combinations

a) PetroLatina Energy Ltd.

On August 23, 2016 (the "PetroLatina Acquisition Date"), the Company acquired all of the issued and outstanding common shares of PetroLatina Energy Ltd. ("PetroLatina") for $525 million, consisting of cash consideration of $465.7 million, which included a deferred cash payment of $25.0 million that was paid on December 31, 2016, assumption of a reserve-backed credit facility with an outstanding balance of $80.0 million (Note 8), net working capital of $17.3 million and other closing adjustments. Upon completion of the transaction on the PetroLatina Acquisition Date, Gran Tierra repaid and canceled the reserve-based credit facility and PetroLatina became an indirect wholly-owned subsidiary of Gran Tierra.

PetroLatina is an exploration and production company, incorporated in England and Wales, with assets primarily in the Middle Magdalena Basin of Colombia. The acquisition added a new core area for Gran Tierra in the prolific Middle Magdalena Basin and was accounted for as a business combination using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recognized at their fair values as at the PetroLatina Acquisition Date, and the results of PetroLatina were included with those of Gran Tierra from that date. Fair value estimates were made based on significant unobservable (Level 3) inputs and based on the best information available at the time.

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

(Thousands of U.S. Dollars)		
Consideration Paid:		
Purchase price	$	525,000
Purchase price adjustments:		
PetroLatina's long-term debt assumed		(80,000)
Working capital and other		20,683
Total cash consideration		465,683
Estimated post-closing adjustments		1,908
Cash consideration paid	$	467,591
Allocation of Total Consideration[2]:		
Oil and gas properties		
Proved[1]	$	360,483
Unproved[1]		432,286
Net working capital (including cash acquired of $15.9 million, restricted cash of $0.7 million and accounts receivable of $4.0 million)		17,302
Long-term restricted cash		3,017
Long-term debt		(80,000)
Long-term deferred tax liability[1]		(262,566)
Long-term portion of asset retirement obligation		(3,870)
Other long-term liabilities		(969)
	$	465,683

[1] During the three months ended December 31, 2016, post-closing adjustments were finalized and this resulted in a $4.3 million increase to total cash consideration. Additionally, management obtained further information about the acquisition date fair value of PetroLatina's proved and unproved properties and working capital and determined that the fair values were $3.9 million lower, $9.6 million higher and $1.8 million higher, respectively, than previously estimated. This resulted in a $3.2 million increase in the acquisition date deferred tax liability. In accordance with GAAP, these changes were accounted for in the three months ended December 31, 2016 without retrospective revision of prior periods. The reduction in the acquisition date fair value of proved properties would have resulted in a $1.0 million net of income tax expense, reduction in the net loss for the three months ended September 30, 2016, as a result of lower Colombian ceiling test impairment losses.

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

The Company's consolidated statement of operations for the year ended December 31, 2016, included oil and gas sales of $11.4 million and net loss after tax of $42.3 million from PetroLatina for the period subsequent to the PetroLatina Acquisition Date.

Pro Forma Results (unaudited)

Pro forma results for the years ended December 31, 2016 and 2015, are shown below, as if the acquisition had occurred on January 1, 2015. Pro forma results are not indicative of actual results or future performance.

	Years Ended December 31,	
(Unaudited, thousands of U.S. Dollars, except per share amounts)	**2016**	**2015**
Oil and gas sales	**$ 323,266**	$ 357,693
Net loss	**$ (309,972)**	$ (288,389)
Net loss per share - basic and diluted	**$ (0.97)**	$ (1.01)

The supplemental pro forma net loss of Gran Tierra for the year ended December 31, 2016, was adjusted to exclude $6.2 million of transaction expenses because they were not expected to have a continuing impact on Gran Tierra's results of operations.

b) Petroamerica Oil Corp.

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

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

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

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

(Thousands of U.S. Dollars)

Consideration Paid:		
Cash	$	70,625
Issuance of Common Shares, net of share issuance costs		25,811
	$	96,436

Allocation of Consideration Paid:		
Oil and gas properties		
Proved[(1)]	$	36,082
Unproved[(1)]		52,232
Net working capital (including cash acquired of $19.7 million, restricted cash of $2.5 million and accounts receivable of $5.0 million)		24,202
Long-term restricted cash		8,167
Other long-term assets		1,570
Long-term deferred tax liability[(1)]		(10,553)
Long-term portion of asset retirement obligation		(11,556)
Other long-term liabilities		(2,779)
Gain on acquisition[(1)]		(929)
	$	96,436

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

As indicated in the allocation of the consideration paid, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration paid. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized an “Other gain” of $0.9 million in the consolidated statement of operations for the year ended December 31, 2016. The gain reflects the impact on Petroamerica’s pre-acquisition market value resulting from the company's lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

The Company's consolidated statement of operations for the year ended December 31, 2016, included oil and gas sales of $17.1 million and net loss after tax of $24.7 million from Petroamerica for the period subsequent to the Petroamerica Acquisition Date.

Pro Forma Results (unaudited)

Pro forma results for the years ended December 31, 2016 and 2015, are shown below, as if the acquisition had occurred on January 1, 2015. Pro forma results are not indicative of actual results or future performance.

	Years Ended December 31,			
(Unaudited, thousands of U.S. Dollars, except per share amounts)	**2016**		**2015**	
Oil and gas sales	**$**	**289,739**	$	332,867
Net loss	**$**	**(466,506)**	$	(276,852)
Net loss per share - basic and diluted	**$**	**(1.45)**	$	(0.97)

The supplemental pro forma net loss of Gran Tierra for the year ended December 31, 2016, was adjusted to exclude the $0.9 million gain on acquisition and $1.2 million of transaction expenses because they were not expected to have a continuing impact on Gran Tierra's results of operations.

4. Discontinued Operations

On June 25, 2014, the Company 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. Revenue and other income and loss from discontinued operations, net of income taxes, for the year ended December 31, 2014, were as follows:

	Year Ended December 31,
(Thousands of U.S. Dollars)	**2014**
Revenue and other income	$ 31,985
Loss from operations of discontinued operations before income taxes	$ (6,252)
Income tax expense	(1,458)
Loss from operations of discontinued operations	(7,710)
Loss on sale before income taxes	(18,235)
Income tax expense	(1,045)
Loss on sale	(19,280)
Loss from discontinued operations, net of income taxes	$ (26,990)

5. Segment and Geographic Reporting

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

On February, 6, 2017, the Company announced that a purchase and sale agreement had been executed by the Purchaser to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (Note 17). The completion of the sale is subject to the Purchaser obtaining financing, as well as customary closing conditions, including the receipt of required regulatory approval from the ANP.

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

	Year Ended December 31, 2016				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 280,872	$ —	$ 8,397	$ —	$ 289,269
DD&A expenses	132,569	544	3,819	2,603	139,535
Asset impairment	514,314	31,192	71,143	—	616,649
General and administrative expenses	17,187	1,643	968	13,420	33,218
Interest income	1,281	8	274	805	2,368
Interest expense	—	—	—	14,145	14,145
Loss from continuing operations before income taxes	(505,447)	(33,181)	(70,591)	(41,015)	(650,234)
Segment capital expenditures [1]	105,963	5,059	15,146	1,621	127,789

	Year Ended December 31, 2015				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 269,035	$ —	$ 6,976	$ —	$ 276,011
DD&A expenses	167,701	789	6,183	1,713	176,386
Asset impairment	235,069	41,916	46,933	—	323,918
General and administrative expenses	9,805	3,800	2,708	16,040	32,353
Interest income	294	2	218	855	1,369
Interest expense	—	—	—	—	—
Loss from continuing operations before income taxes	(238,463)	(51,675)	(54,968)	(22,982)	(368,088)
Segment capital expenditures	85,326	50,203	20,014	1,096	156,639

	Year Ended December 31, 2014				
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 532,196	$ —	$ 27,202	$ —	$ 559,398
DD&A expenses	174,063	690	9,932	1,192	185,877
Asset impairment	—	265,126	—		265,126
General and administrative expenses	19,431	6,448	3,698	21,672	51,249
Interest income	569	1	1,604	682	2,856
Interest expense	—	—	—	—	—
Income (loss) from continuing operations before income taxes	279,924	(274,207)	5,921	(28,772)	(17,134)
Segment capital expenditures	206,520	158,266	23,873	2,867	391,526

[1] On January 13, 2016 and August 23, 2016, respectively, the Company acquired all of the issued and outstanding common shares of Petroamerica and PetroLatina, which acquisitions were accounted for as business combinations (Note 3) and, therefore, property, plant and equipment acquired are not reflected in the table above. Additionally, on January 25, 2016, the Company acquired all of the issued and outstanding common shares of PetroGranada Colombia Limited ("PGC"), which acquisition was accounted for as an asset acquisition (Note 7) and property, plant and equipment acquired in this acquisition are not reflected in the table above.

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

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

The following table presents the number of customers from whom the Company derived 10% or more of its consolidated oil and gas sales and sales as a percentage of the Company's consolidated oil and gas sales to each customer. All of these customers were in the Company's Colombian reportable segment:

	Year Ended December 31, 2016	2015	2014
Number of significant customers	**3**	4	2
Sales to each significant customer as % of oil and gas sales	**40% 34% 13%**	43% 15% 13% 12%	52% 32%

6. Accounts Receivable and Inventory

Accounts Receivable

(Thousands of U.S. Dollars)	As at December 31, 2016	2015
Trade	**$ 39,203**	$ 26,924
Other	**6,495**	2,293
	$ 45,698	$ 29,217

Inventory

At December 31, 2016, oil and supplies inventories were $6.0 million and $1.8 million, respectively (December 31, 2015 - $17.8 million and $1.3 million, respectively). At December 31, 2016, the Company had 208 Mbbl of oil inventory (December 31, 2015 - 616 Mbbl) NAR. In the year ended December 31, 2016, the Company recorded oil inventory impairment of $0.7 million (year ended December 31, 2015 - $2.6 million, year ended December 31, 2014 - $nil) related to lower oil prices (Note 7).

7. Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at December 31, 2016	2015
Oil and natural gas properties		
Proved	**$ 2,652,171**	$ 1,998,330
Unproved	**647,774**	310,771
	3,299,945	2,309,101
Other	**29,445**	28,342
	3,329,390	2,337,443
Accumulated depletion, depreciation and impairment	**(2,262,781)**	(1,548,450)
	$ 1,066,609	$ 788,993

In the year ended December 31, 2016, the Company recorded ceiling test impairment losses of $513.7 million in its Colombia cost center, and $71.1 million in its Brazil cost center. The Colombia ceiling test impairment loss related to lower oil prices and the fact that the acquisitions of PetroLatina and PetroAmerica were initially added into the cost base at estimated fair value (Note 3). However, these acquired assets were subjected to a prescribed U.S. GAAP ceiling test, which is not a fair value test, and which, as noted below, uses constant commodity pricing that averages prices during the preceding 12 months. The Brazil ceiling test impairment loss related to continued low oil prices and increased costs in the depletable base as a result of a $45.0 million impairment of unproved properties.

In the year ended December 31, 2015, the Company recorded ceiling test impairment losses of $232.4 million in its Colombia cost center, and $46.9 million in its Brazil cost center as a result of lower realized prices.

The Company follows the full cost method of accounting for its oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is then held constant, except for changes which are fixed and determinable by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year and it should not be assumed that estimates of future net revenues represent the fair market value of the Company's reserves. In accordance with GAAP, Gran Tierra used an average Brent price of $42.92 per bbl for the purposes of the December 31, 2016, ceiling test calculations (December 31, 2015 - $54.08).

In the year ended December 31, 2016, the Company recorded impairment losses in its Peru cost center of $31.2 million related to costs incurred on Block 95, and other blocks. In the years ended December 31, 2015 and 2014, the Company recorded impairment losses of $41.9 million and $265.1 million, respectively, related to costs incurred on Block 95. On February 19, 2015, the Company made the decision to cease all further development expenditures on the Bretaña Field on Block 95 other than what is necessary to maintain tangible asset integrity and security. In the three months ended September 30, 2016, the Company ceased the impairment of costs incurred on Block 95 as a result of the effect of a revised field development plan for the Block.

Asset impairment for the three years ended December 31, 2016, was follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2016	2015	2014
Impairment of oil and gas properties	**$ 615,985**	$ 321,285	$ 265,126
Impairment of inventory (Note 6)	**664**	2,633	—
	$ 616,649	$ 323,918	$ 265,126

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2016, was $130.2 million (year ended December 31, 2015 - $177.9 million; year ended December 31, 2014 - $187.9 million). A portion of depletion and depreciation expense was recorded as inventory in each year and adjusted for inventory changes.

Acquisition of PGC

On January 25, 2016, the Company acquired all of the issued and outstanding common shares of PGC, pursuant to the terms and conditions of an acquisition agreement dated January 14, 2016. PGC is an oil and gas exploration, development and production company active in Colombia. Upon completion of the transaction, PGC became an indirect wholly-owned subsidiary of Gran Tierra. The net purchase price of PGC was $19.4 million, after giving consideration to net working capital of $18.3 million. The acquisition was accounted for as an asset acquisition with the excess consideration paid over the fair value of the net assets acquired allocated on a relative fair value basis to the net assets acquired.

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

(Thousands of U.S. Dollars)		
Cost of asset acquisition:		
Cash	$	37,727
Allocation of Consideration Paid:		
Oil and gas properties		
Proved	$	12,228
Unproved		15,563
		27,791
Net working capital (including cash acquired of $0.2 million and restricted cash of $18.6 million)		18,339
Long-term deferred tax liability		(8,403)
	$	37,727

Contingent consideration of $4.0 million will be payable if cumulative production from the Putumayo-7 Block plus gross proved plus probable reserves under the Putumayo-7 Block meet or exceed 8 MMbbl. Contingent consideration will be recognized when the contingency is resolved and the consideration is paid or becomes payable.

On November 25, 2016, Gran Tierra submitted winning bids totaling a combined $30.4 million for two blocks which Ecopetrol offered as part of an asset disposition process. Gran Tierra's winning bids were on the Santana and Nancy-Burdine-Maxine Blocks, which are located in the Putumayo Basin. At December 31, 2016, the assignments of working interests in these blocks was not complete. Ecopetrol will transfer ownership of the blocks' assets, contracts, permits and licenses, as well as 100% ownership of Ecopetrol's rights and obligations in respect of the oil and gas assets, to Gran Tierra once the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) grants approval and the conditions of the assignment agreement are met. The purchase price of $30.4 million will be paid from the Company's credit facility. Additionally, Gran Tierra sold non-operated and non-core assets in Colombia to a third party for cash consideration of $6.0 million.

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Brazil and Peru. The following table provides a summary of Gran Tierra’s unproved properties as at December 31, 2016:

	As at December 31,			
(Thousands of U.S. Dollars)		**2016**		**2015**
Colombia	**$**	**561,463**	$	147,500
Brazil		**67,866**		69,089
Peru		**18,445**		94,182
	$	**647,774**	$	310,771

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. The Company expects that approximately 74% of costs not subject to depletion at December 31, 2016, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2016:

	Costs Incurred in				
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**	**Prior to 2014**	**Total**
Acquisition costs - Colombia	**$ 429,626**	**$ —**	**$ —**	**$ 48,810**	**$ 478,436**
Acquisition costs - Peru	**—**	**—**	**—**	**11,500**	**11,500**
Acquisition costs - Brazil	**—**	**—**	**—**	**5,949**	**5,949**
Exploration costs - Colombia	**10,823**	**16,840**	**29,969**	**25,394**	**83,026**
Exploration costs - Peru	**3,213**	**7,471**	**29,424**	**16,258**	**56,366**
Exploration costs - Brazil	**79**	**4,714**	**2,024**	**5,680**	**12,497**
Total oil and natural gas properties not subject to depletion	**$ 443,741**	**$ 29,025**	**$ 61,417**	**$ 113,591**	**$ 647,774**

8. Debt and Debt Issuance Costs

The Company's debt at December 31, 2016 and 2015, was as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Convertible senior notes (a)	**$ 115,000**	$ —
Revolving credit facility (b)	**90,000**	—
Unamortized debt issuance costs	**(7,917)**	—
Long-term debt	**$ 197,083**	$ —

a) Convertible Senior Notes

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

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

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

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

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

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

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

Net proceeds from the sale of the Notes were $109.1 million, after deducting the initial purchasers' discount and the offering expenses payable by the Company.

b) Credit Facility

At December 31, 2016, the Company had a revolving credit facility with a syndicate of lenders. On November 16, 2016, the Company entered into a Fourth Amendment (the "Fourth Amendment") to its credit agreement dated September 18, 2015 (the "Credit Agreement"). The Fourth Amendment, among other things, increased the borrowing base from $185.0 million, with $160.0 million readily available and $25.0 million subject to the consent of all lenders, to $250 million readily available. Availability under the revolving credit facility is determined by the reserves-based borrowing base determined by the lenders. The borrowing base will be re-determined semi-annually and will be re-determined no later than May 2017. The Company’s revolving credit facility is secured against the assets of the Company’s subsidiaries in Colombia, Canada and the United States of America (the "Credit Facility Group"). The credit agreement includes a letter of credit sub-limit of up to $100 million. None of the letter of credit sub-limit had been used at December 31, 2016. Borrowings under the revolving credit facility will mature on September 18, 2018. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility and, if the Company is not in default, it is required to obtain bank approval for dividend payments to shareholders outside of the Credit Facility Group.

Amounts drawn down under the revolving credit facility bear interest, at the Company's option, at the USD LIBOR rate plus a margin ranging from 2.00% and 3.00% per annum, or an alternate base rate plus a margin ranging from 1.00% per annum to 2.00% per annum, in each case based on the borrowing base utilization percentage. The alternate base rate is currently the U.S. prime rate. At December 31 2016, the weighted-average interest rate on the balance outstanding on the Company's revolving credit facility was approximately 2.96%. Undrawn amounts under the revolving credit facility bear interest at 0.75% per annum, based on the average daily amount of unused commitments. A letter of credit participation fee of 0.25% per annum will accrue on the average daily amount of letter of credit exposure.

On August 23, 2016, the Company entered into a Third Amendment (the "Third Amendment") to the Credit Agreement to add a bridge term loan facility (the “Bridge Loan Facility”), pursuant to which the lenders provided $130.0 million in secured bridge loan financing to fund a portion of the purchase price of the PetroLatina acquisition. The Bridge Loan Facility had a term of 364 days, bore interest at USD LIBOR plus 6%, and had customary bridge facility repayment terms, providing for the prepayment of the Bridge Loan Facility upon the occurrence of certain events, including certain debt issuances. It was otherwise on substantially the same terms as the existing secured revolving credit facility.

On August 23, 2016, in connection with the PetroLatina acquisition, the Company drew $95.0 million on its revolving credit facility and $130.0 million on its Bridge Loan Facility. During the three months ending September 30, 2016, the Company repaid $30.0 million of the balance outstanding on its revolving credit facility.

During the three months ending December 31, 2016, upon the sale of non-core assets (Note 7), the Company repaid $5.0 million of the balance outstanding on the Bridge Loan Facility and, concurrent with the effectiveness of the Fourth Amendment, repaid the remaining balance on the Bridge Loan Facility using available borrowing capacity under its Credit Agreement. This resulted in a balance outstanding on its revolving credit facility of $190 million. The Company subsequently drew an additional $37.0 million on its revolving credit facility and repaid $137.0 million of the balance outstanding on this facility primarily using proceeds from its November 2016 equity offering (Note 9).

As part of the PetroLatina acquisition, Gran Tierra assumed PetroLatina's reserve-backed credit facility with an outstanding balance as at the PetroLatina Acquisition Date of $80.0 million. This credit facility plus accrued interest was repaid by Gran Tierra upon closing of the PetroLatina Acquisition on August 23, 2016.

c) Interest expense

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Contractual interest and other financing expenses	**$ 8,454**	$ —	$ —
Amortization of debt issuance costs	**5,691**	—	—
	$ 14,145	$ —	$ —

The Company incurred debt issuance costs in connection with the issuance of the Notes, the Bridge Loan Facility and its revolving credit facility. As at December 31, 2016, the balance of unamortized debt issuance costs has been presented as a direct deduction against the carrying amount of debt and is being amortized to interest expense using the effective interest method over the term of the debt.

9. 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 December 31, 2016, outstanding share capital consists of 390,807,194 shares of Common Stock of the Company, 4,812,592 exchangeable shares of Gran Tierra Exchangeco Inc., (the "Exchangeco exchangeable shares") and 3,387,302 exchangeable shares of Gran Tierra Goldstrike Inc. (the "Goldstrike exchangeable shares"). The Exchangeco exchangeable shares were issued upon the acquisition of Solana. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. 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.

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.

	Shares of Common Stock	Exchangeable Shares of Gran Tierra Exchangeco Inc.	Exchangeable Shares of Gran Tierra Goldstrike Inc.
Balance, December 31, 2015	273,442,799	4,933,177	3,638,889
Shares issued upon conversion of subscription receipts (a)	57,835,134	—	—
Shares issued upon public offering (b)	43,335,000	—	—
Shares issued for acquisition (Note 3)	13,656,719	—	—
Options exercised	2,165,370	—	—
Exchange of exchangeable shares	372,172	(120,585)	(251,587)
Balance, December 31, 2016	390,807,194	4,812,592	3,387,302

a) Subscription Receipts

On July 8, 2016, the Company issued approximately 57.8 million subscription receipts ("Subscription Receipts") in a private placement to eligible purchasers at a price of $3.00 per Subscription Receipt for gross proceeds of $173.5 million, or net proceeds after share issuance costs of $165.8 million. The proceeds were used to partially fund the PetroLatina acquisition. Each Subscription Receipt entitled the holder to automatically receive one common share of the Company upon closing of the PetroLatina acquisition on the satisfaction of certain conditions. Upon the closing of the PetroLatina acquisition on August 23, 2016, each Subscription Receipt was converted to one common share.

b) Public Offering

On November 29, 2016, the Company issued approximately 43.3 million shares of its common stock at a public offering price of $3.00 per share for gross proceeds of $130.0 million, or net proceeds after share issuance costs of $123.0 million (the "Offering"). The proceeds were used to repay borrowings outstanding under the Company's revolving credit facility.

2015 Share Repurchase Program

During 2015, the Company repurchased and canceled 4.6 million shares at an average price of $2.19 for total proceeds of $10.0 million, pursuant to the terms of a share repurchase program (the "2015 Program") through the facilities of the Toronto Stock Exchange, the NYSE MKT and eligible alternative trading platforms in Canada and the United States. The 2015 Program expired on July 29, 2016.

Equity Compensation Awards

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

In prior years, all equity awards were subject to vesting conditions based solely on the recipient's continued employment over a specified period of time. In contrast, 80% of the equity awards granted in early 2016 consisted of Performance Stock Units ("PSUs") and 20% consisted of stock options. Gran Tierra's Compensation Committee and Board of Directors believed it was important to revise the Company's long-term incentive program to incorporate a new form of equity award that vests based on the achievement of certain key measures of performance. The purpose of this change was to align the Company's executives and employees to achieve the operational goals established by the Board of Directors, total shareholder return and increase the net asset value per share for stockholders. The Company's equity compensation awards outstanding as at December 31, 2016, include PSUs, deferred share units ("DSUs"), restricted stock units ("RSUs") and stock options.

In accordance with the 2007 Equity Incentive Plan, the Company's Board of Directors is authorized to issue options or other rights to acquire shares of the Company's Common Stock. On June 27, 2012, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares.

The following table provides information about PSU, DSU, RSU and stock option activity for the year ended December 31, 2016:

	PSUs	DSUs	RSUs	Stock Options	
	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Share Units	Number of Outstanding Options	Weighted Average Exercise Price $/ Option
Balance, December 31, 2015	—	—	1,015,457	12,851,557	$ 4.60
Granted	3,362,717	208,698	—	1,744,165	2.69
Exercised	—	—	(476,972)	(2,165,370)	2.47
Forfeited	—	—	(179,340)	(386,320)	(4.71)
Expired	—	—	—	(2,804,554)	(6.49)
Balance, December 31, 2016	3,362,717	208,698	359,145	9,239,478	$ 4.16
Exercisable, at December 31, 2016				5,068,834	$ 5.03
Vested, or expected to vest, at December 31, 2016, through the life of the options				9,000,561	$ 4.19

Stock-based compensation expense for the year ended December 31, 2016, was $6.3 million (December 31, 2015 - $2.7 million; December 31, 2014 - $7.7 million) and was primarily recorded in G&A expenses.

At December 31, 2016, there was $10.0 million (December 31, 2015 - $3.9 million) of unrecognized compensation cost related to unvested PSUs, RSUs and stock options which is expected to be recognized over a weighted average period of 1.8 years. The weighted-average remaining contractual term of options vested, or expected to vest, at December 31, 2016 was 3.5 years.

PSUs

PSUs entitle the holder to receive, at the option of the Company, either the underlying number of shares of the Company's Common Stock upon vesting of such units or a cash payment equal to the value of the underlying shares. PSUs will cliff vest after three years, subject to the continued employment of the grantee. The number of PSUs that vest may range from zero to 200% of the target number granted based on the Company’s performance with respect to the applicable performance targets. The performance targets for the PSUs outstanding as at December 31, 2016, are as follows:

(i) 50% of the award is subject to targets relating to the total shareholder return (“TSR”) of the Company against a group of peer companies

(ii) 25% of the award is subject to targets relating to net asset value ("NAV") of the Company per share and NAV is based on before tax net present value discounted at 10% of proved plus probable reserves; and

(iii) 25% of the award is subject to targets relating to the execution of corporate strategy.

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

DSUs and RSUs

DSUs and RSUs entitle the holder to receive, either the underlying number of shares of the Company's Common Stock upon vesting of such units or, at the option of the Company, a cash payment equal to the value of the underlying shares. The Company's historic practice has been to settle RSUs in cash and the Company currently intends to settle the RSUs and DSUs outstanding as at December 31, 2016 in cash, and, therefore, DSUs and RSUs are accounted for as liability instruments. Once a DSU or RSU is vested, it is immediately settled. During the year ended December 31, 2016, DSUs were granted to directors and will vest 100% at such time the grantee ceases to be a member of the Board of Directors. For the year ended December 31, 2016, the Company paid $1.2 million to cash settle RSUs (2015 - $1.4 million and 2014 - $3.4 million).

Stock Options

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

For the year ended December 31, 2016, 2,165,370 shares of Common Stock were issued for cash proceeds of $5.3 million upon the exercise of 2,165,370 stock options (2015 – 390,000; 2014 – 3,029,853).

At December 31, 2016, the weighted average remaining contractual term of outstanding stock options was 3.5 years and of exercisable stock options was 3.3 years.

The fair value of each stock option award is estimated on the date of grant using the Black-Scholes option pricing model based on assumptions noted in the following table:

	Year Ended December 31,		
	2016	2015	2014
Dividend yield (per share)	**Nil**	Nil	Nil
Volatility	**50% to 54%**	46% to 50%	39% to 42%
Weighted average volatility	**52%**	48%	41%
Risk-free interest rate	**0.94% to 1.78%**	1.20% to 1.68%	0.78% to 1.45%
Expected term	**4-5 years**	4-5 years	4-5 years

The weighted average grant date fair value for options granted in the year ended December 31, 2016, was $1.14 (2015 - $1.24; 2014 - $2.47). The weighted average grant date fair value for options vested in the year ended December 31, 2016, was $1.52 (2015 - $2.38; 2014 - $3.63). The total fair value of stock options vested during year ended December 31, 2016, was $2.8 million (2015 - $6.8 million; 2014 - $12.4 million).

Weighted Average Shares Outstanding

	Year Ended December 31,		
	2016	2015	2014
Weighted average number of common and exchangeable shares outstanding	**320,851,538**	285,333,869	284,715,785
Shares issuable pursuant to stock options	**—**	—	—
Shares assumed to be purchased from proceeds of stock options	**—**	—	—
Weighted average number of diluted common and exchangeable shares outstanding	**320,851,538**	285,333,869	284,715,785

For the year ended December 31, 2016, 10,662,034 options, on a weighted average basis, (2015 - 13,432,287 options; 2014 - 15,621,890 options) were excluded from the diluted loss per share calculation as the options were anti-dilutive.

10. 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:

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2016**	2015
Balance, beginning of year	**$ 33,224**	$ 35,812
Settlements	**(872)**	(6,317)
Liabilities associated with assets sold	**(3,257)**	—
Liability incurred	**2,606**	1,556
Liabilities assumed in acquisitions (Note 3)	**15,723**	—
Accretion	**2,789**	1,313
Revisions in estimated liability	**(6,856)**	860
Balance, end of year	**$ 43,357**	$ 33,224
Asset retirement obligation - current	**$ 5,215**	$ 2,146
Asset retirement obligation - long-term	**38,142**	31,078
Balance, end of year	**$ 43,357**	$ 33,224

For the year ended December 31, 2016, settlements included cash payments of $0.6 million with the balance in accounts payable and accrued liabilities at December 31, 2016. Revisions in estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. At December 31, 2016, the fair value of assets that are legally restricted for purposes of settling asset retirement obligations was $12.0 million (December 31, 2015 - $2.9 million). These assets are accounted for as restricted cash on the Company's balance sheet.

11. Taxes

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2016**	**2015**	**2014**
Loss from continuing operations before income taxes			
United States	**$ (23,986)**	$ (14,061)	$ (19,744)
Foreign	**(626,248)**	(354,027)	2,610
	(650,234)	(368,088)	(17,134)
	35%	35%	35%
Income tax recovery expense from continuing operations expected	**(227,582)**	(128,831)	(5,997)
Foreign currency translation adjustments	**218**	(187)	(6,520)
Impact of foreign taxes[1]	**(9,799)**	(13,087)	27,910
Other local taxes	**1,998**	2,354	4,433
Stock-based compensation	**1,955**	919	2,232
Increase in valuation allowance	**47,675**	37,691	94,922
Non-deductible third party royalty in Colombia	**2,550**	3,416	9,116
Other permanent differences	**(1,684)**	(2,334)	1,119
Total income tax (recovery) expense from continuing operations	**$ (184,669)**	$ (100,059)	$ 127,215
Current income tax expense from continuing operations			
United States	**$ 1,818**	$ 1,070	$ 1,260
Foreign	**18,304**	14,313	91,605
	20,122	15,383	92,865
Deferred income tax (recovery) expense from continuing operations			
Foreign[2]	**(204,791)**	(115,442)	34,350
Total income tax (recovery) expense from continuing operations	**$ (184,669)**	$ (100,059)	$ 127,215

[1] Impact of foreign taxes in the rate reconciliation are tax effected at the 35% statutory rate and for the years ended December 31, 2016, 2015 and 2014, included $23.3 million, $11.8 million and $28.1 million, respectively, in Colombia.

[2] The deferred tax recovery for the year ended December 31, 2016, included $201.3 million associated with the ceiling test impairment loss in Colombia.

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	**$ 74,604**	$ 56,015
Tax basis in excess of book basis	**187,651**	139,012
Foreign tax credits and other accruals	**48,341**	22,674
Tax benefit of capital loss carryforwards	**32,278**	30,799
Deferred tax assets before valuation allowance	**342,874**	248,500
Valuation allowance	**(341,263)**	(245,259)
	1,611	3,241
Deferred Tax Liabilities	**107,230**	34,592
Net Deferred Tax Liabilities	**$ (105,619)**	$ (31,351)

(Thousands of U.S. Dollars)	As at December 31, 2016	2015
Operating loss carryforwards	**$ 257,023**	$ 178,677
Capital loss carryforwards	**$ 239,095**	$ 228,144
Of the operating loss and capital loss carryforwards, losses generated by the foreign subsidiaries of the Company.	**$ 496,118**	$ 355,875

In certain jurisdictions, the operating loss carryforwards expire between 2017 and 2036, while certain other jurisdictions allow operating losses to be carried forward indefinitely. The capital losses can be carried forward indefinitely.

The valuation allowance increased by $96.0 million during the year ended December 31, 2016, which included $48.3 million of acquisition date valuation allowances for Petroamerica and PetroLatina. The change in the valuation allowance was primarily due to impairment losses recorded in Peru and Brazil and an increase in the corporate tax rate in Canada, partially offset by foreign currency translation adjustments. Also, the Company continues to incur losses in the U.S., Peru, Brazil and Canada. These losses are fully offset by a valuation allowance as their recognition does not meet the "more likely than not" threshold.

In the fourth quarter of 2016, Congressional authorities in Colombia enacted new legislation which consolidated the corporate income tax and CREE tax into a single income tax at 40% for 2017 (including a surtax of 6%), 37% for 2018 (including a surtax of 4%) and 33% for 2019 and onwards. The tax rates applied to the calculation of deferred income taxes have been adjusted to reflect these changes and resulted in a decrease of the future Colombian tax liability by approximately $4.1 million when tax effected at 40%. This legislation also introduced a new 5% dividend tax on distributions of previously taxed earnings from 2017 and onwards. Additionally, the legislation increased the corporate minimum presumptive income tax from 3% to 3.5%. This tax is imposed on a taxpayer's net equity at the prior year-end when the presumptive CIT exceeds actual taxable profits.

Undistributed earnings of foreign subsidiaries as of December 31, 2016, were considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

Effective November 1, 2016, several of Gran Tierra's subsidiaries executed intercompany sale agreements whereby certain depreciable assets were transferred within the consolidated Gran Tierra group. The purpose of the transaction was to improve the efficiency of Gran Tierra's operating and tax structures. The restructuring resulted in a consolidation of certain assets into a single entity in Colombia, an increase in the depreciable tax basis of the assets transferred, and current income taxes payable as at December 31, 2016, as a result of the capital gains taxes incurred. GAAP prohibits the recognition of current and deferred income taxes for intra-entity transfers until an asset leaves the consolidated group, therefore, the current and deferred income tax effect of the restructuring was deferred and recognized as prepaid income taxes at December 31, 2016. Since the date of the transfer, prepaid income taxes were amortized in accordance with accounting depreciation. Including the effect of tax reorganizations completed earlier in the year, at December 31, 2016, the Company's balance sheet included $54.1 million of prepaid income taxes, $12.3 million in current prepaid taxes and $41.8 million in long-term prepaid taxes, and $37.5 million of current income taxes payable.

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

(Thousands of U.S. Dollars)	Year Ended December 31, 2016	2015	2014
Unrecognized tax benefit relating to loss or income from continuing operations, beginning of year	**$ 2,200**	$ 3,300	$ 2,900
Increases for positions relating to prior year	**—**	—	500
Decreases for positions relating to prior year		(800)	(100)
Decreases due to lapse of statute of limitations	**(2,200)**	(300)	—
Unrecognized tax benefit relating to loss or income from continuing operations, end of year	**$ —**	$ 2,200	$ 3,300
Interest and penalties (recovery) expense on the unrecognized tax benefit included in income tax expense from continuing operations	**$ —**	$ (600)	$ 400

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 consolidated statement of operations. As at December 31, 2016, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the consolidated balance sheet was approximately $nil (December 31, 2015 - $1.4 million).The Company had no other material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2016, respectively.

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 2009 through 2016 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 legislation which imposes an equity tax levied on Colombian operations for 2015, 2016 and 2017. The equity tax is calculated based on a legislated measure, which is based on the Company’s Colombian legal entities' balance sheet equity for tax purposes at January 1, 2015. This measure is subject to adjustment for inflation in future years. The equity tax rates for January 1, 2015, 2016 and 2017, are 1.15%, 1% and 0.4%, respectively. The legal obligation for each year's equity tax liability arises on January 1 of each year; therefore, the Company recognized the annual amount of $3.1 million and $3.8 million for the equity tax expense in the consolidated statement of operations for the years ended December 31, 2016 and 2015. These amounts were paid in May and September of each year and at December 31, 2016, accounts payable included $nil (December 31, 2015 - $nil).

12. Accounts Payable and Accrued Liabilities

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Trade	**$ 80,072**	$ 54,402
Royalties	**4,542**	2,066
Employee compensation and severance	**8,152**	8,414
Other	**14,285**	5,896
	$ 107,051	$ 70,778

13. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

As at December 31, 2016, future minimum payments under non-cancelable agreements with remaining terms in excess of one year were as follows:

	Year ending December 31						
	Total	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
(Thousands of U.S. Dollars)							
Oil transportation services	$ 13,958	$ 3,639	$ 3,639	$ 3,639	$ 3,041	$ —	$ —
Drilling, completions and seismic	4,159	2,172	1,987	—	—	—	—
Operating leases	4,111	1,971	1,259	412	402	67	—
Software and telecommunication	35	24	11	—	—	—	—
	$ 22,263	$ 7,806	$ 6,896	$ 4,051	$ 3,443	$ 67	$ —

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for the year ended December 31, 2016, was $3.2 million (year ended December 31, 2015 – $4.0 million; year ended December 31, 2014 - $3.2 million).

Indemnities

Corporate indemnities have been provided by the Company to directors and officers for various items including, but not limited to, all costs to settle suits or actions due to their association with the Company and its subsidiaries and/or affiliates, subject to certain restrictions. The Company has purchased directors' and officers' liability insurance to mitigate the cost of any potential future suits or actions. The maximum amount of any potential future payment cannot be reasonably estimated. The Company may provide indemnifications in the normal course of business that are often standard contractual terms to counterparties in certain transactions such as purchase and sale agreements. The terms of these indemnifications will vary based upon the contract, the nature of which prevents the Company from making a reasonable estimate of the maximum potential amounts that may be required to be paid.

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.

Letters of credit

At December 31, 2016, the Company had provided promissory notes totaling $96.8 million (December 31, 2015 - $76.5 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

Contingencies

On June 6, 2016, the Company received a positive decision from the Chamber of Commerce of Bogotá Center for Arbitration and Conciliation tribunal (the "Tribunal") relating to its dispute with the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) of Colombia ("ANH") with respect to whether all production from the Moqueta Exploitation Area of the Chaza Block exploration and production contract ("Chaza Contract") was subject to an additional royalty (the "HPR Royalty"). In its decision, the Tribunal found that the HPR Royalty under the Chaza Contract was only payable when the accumulated oil production from the Moqueta Exploitation Area exceeded 5.0 MMbbl. That production threshold was reached on April 30, 2015, and since that time the Company has been paying the HPR Royalty on production from the Moqueta Exploitation Area.

The ANH and Gran Tierra are engaged in ongoing discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH's interpretation is correct could be up to $45.9 million as at December 31, 2016. At this time no amount has been accrued in the consolidated financial statements as Gran Tierra does not consider it probable that a loss will be incurred.

In addition to the above, Gran Tierra has a number of 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.

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

Financial Instruments

At December 31, 2016, the Company's financial instruments recognized in the balance sheet consist of; cash and cash equivalents; restricted cash; accounts receivable; derivative assets and liabilities; accounts payable and accrued liabilities; long-term debt; PSU liability included in other long-term liabilities; and RSU liability included in accounts payable and accrued liabilities and other long-term liabilities.

Fair Value Measurement

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

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

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

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

The fair value of trading securities, derivative assets, and RSU and PSU liabilities at December 31, 2016, and December 31, 2015 were as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2016**	**2015**
Foreign currency derivative asset	**$ 578**	$ —
Trading securities	**—**	6,250
	$ 578	$ 6,250
Commodity price derivative liability	**$ 3,824**	$ —
RSU, PSU and DSU liability	**3,907**	1,189
	$ 7,731	$ 1,189

During the year ended December 31, 2016, the Company sold the trading securities for cash proceeds of $2.3 million (year ended December 31, 2015 - nil). These cash proceeds were included in cash flows from investing activities in the Company's consolidated statements of cash flows because these securities were received in connection with the sale of the Company's Argentina business unit in 2014.

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

(Thousands of U.S. Dollars)	Year Ended December 31,		
	2016	**2015**	**2014**
Trading securities loss	**$ 3,925**	$ 1,335	$ 6,326
Commodity price derivative loss	**7,370**	—	—
Foreign currency derivatives (gain) loss	**(1,016)**	692	(1,604)
	$ 10,279	$ 2,027	$ 4,722

These losses are presented as financial instruments loss in the consolidated statements of operations and cash flows. Trading securities losses related to losses on the Madalena shares Gran Tierra received in connection with the sale of its Argentina business unit in June 2014 (Note 4). All trading securities were sold during the year ended December 31, 2016 and the trading securities loss represented a realized loss. For the years ended December 31, 2015 and 2014, the trading securities loss represented an unrealized loss.

Financial instruments not recorded at fair value include the Notes (Note 8). At December 31, 2016, the carrying amount of the Notes was $109.9 million, which represents the aggregate principal amount less unamortized debt issuance costs, and the fair value was $135.6 million. The fair value of long-term restricted cash and the revolving credit facility approximated their carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments.

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

The fair value of the RSU liability was determined using Level 1 inputs. The fair value of the derivatives was determined using Level 2 inputs. The fair value of the PSU liability was determined using Level 3 inputs.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. The fair value of debt is the estimated amount the Company would have to pay a third party to assume the debt, including a credit spread for the difference between the issue rate and the period end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's Notes and revolving credit facility to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The disclosure in the paragraph above regarding the fair value of the Company's revolving credit facility was determined using an income approach using Level 3 inputs. The disclosure in the paragraph above regarding the fair value of the Notes was determined using Level 2 inputs based on the indicative pricing published by certain investment banks or trading levels of the Notes, which are not listed on any securities exchange or quoted on an inter-dealer automated quotation system. The disclosure in the paragraph above regarding the fair value of cash and restricted cash was based on Level 1 inputs.

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

Commodity Price Derivatives

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

At December 31, 2016, the Company had outstanding commodity price derivative positions as follows:

Period and type of instrument	Volume, bopd	Reference	Sold Put ($/bbl)	Purchased Put ($/bbl)	Sold Call ($/bbl)	Premiums received/ (paid) ($/bbl)
Collar: June 1, 2016 to May 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ (1.25)
Collar: June 1, 2017 to December 31, 2017	10,000	ICE Brent	$ 35	$ 45	$ 65	$ 0.475
Collar: October 1, 2016 to December 31, 2017	5,000	ICE Brent	$ 35	$ 45	$ 65	$ —

During the year ended December 31, 2016, the Company paid net premiums upon entering into commodity price derivatives of $3.5 million.

Collars are a combination of put options (floor) and sold call options (ceiling). For a collar position, the counterparty is required to make a payment to the Company if the settlement price for any settlement period is below the floor strike price while the Company is required to make payment to the counterparty if the settlement price for any settlement period is above the ceiling strike price. Neither party is required to make a payment to the other party if the settlement price for any settlement period is equal to or greater than the floor strike price and equal to or less than the ceiling strike price. At December 31, 2015, we did not have any open commodity price derivative positions.

Foreign Exchange Risk and Foreign Currency Derivatives

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

At December 31, 2016, the Company had outstanding foreign currency derivative positions as follows:

Period and type of instrument	Amount hedged (Millions COP)	Reference	Purchased Call (COP)	Sold Put[1] (COP)	Sold Put[1] (COP)
Collar: January 1, 2017 to March 31, 2017	31,597.6	COP	3,100	3,300	3,345
Collar: April 1, 2017 to May 31, 2017	22,697.2	COP	3,100	3,310	3,370
	54,294.8				

[1] The put levels noted in the table above varied based on market conditions at the inception of each foreign currency derivative contract.

At December 31, 2015, the Company did not have any open foreign currency derivative positions. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on the Company's derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. These cash settlements were included in cash flows from operating activities in the Company's consolidated statements of cash flows.

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

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 $43,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar. This effect was calculated based on the Company's December 31, 2016, deferred tax balances, adjusted for the expected effect of the adoption of ASU 2016-16.

For the year ended December 31, 2016, 97% (year ended December 31, 2015 - 97%, year ended December 31, 2014 - 95%) of the Company's oil and natural gas sales were 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 and cash equivalents, restricted cash and accounts receivable. The carrying value of cash and cash equivalents, restricted cash and accounts receivable reflects management’s assessment of credit risk.

At December 31, 2016, cash and cash equivalents and restricted cash included balances in bank accounts, term deposits and certificates of deposit, placed with financial institutions with strong investment grade ratings or governments.

Most of the Company’s accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues 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. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the year ended December 31, 2016, the Company had three customers which were significant to the Colombian segment, and one customer which was significant to the Brazil segment.

To reduce the concentration of exposure to any individual counterparty, the Company utilizes a group of investment-grade rated financial institutions, for its derivative transactions. The Company monitors counterparty creditworthiness on an ongoing basis; however, it cannot predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, the Company may be limited in its ability to mitigate an increase in counterparty credit risk. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments.

15. Severance Expenses

During the years ended December 31, 2016 and 2015, the Company reduced the number of its employees and contractors. Severance expenses were recorded as incurred based on existing employee contracts, statutory requirements, completed negotiations and company policy. Severance expenses were $1.3 million, $9.0 million and $nil in the three years ended December 31, 2016. At December 31, 2015, $nil (December 31, 2014 - $1.5 million) severance expense was payable.

16. Supplemental Cash Flow Information

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

	Year Ended December 31,		
	2016	**2015**	**2014**
Accounts receivable and other long-term assets	**$ (29)**	$ 44,365	$ (34,473)
Derivatives	**(3,546)**	—	—
Inventory	**5,510**	(1,571)	(2,891)
Other prepaids	**(615)**	152	4
Accounts payable and accrued and other long-term liabilities	**(9,691)**	(33,743)	2,988
Prepaid tax and taxes receivable and payable	**(2,966)**	(48,251)	(61,064)
Net changes in assets and liabilities from operating activities of continuing operations	**$ (11,337)**	$ (39,048)	$ (95,436)

The following table provides additional supplemental cash flow disclosures:

	Year Ended December 31,		
	2016	**2015**	**2014**
Cash paid for income taxes	**$ 64,067**	$ 39,422	$ 101,179
Cash paid for interest	**$ 5,624**	$ —	$ —
Non-cash investing activities:			
Net liabilities related to property, plant and equipment, end of year	**$ 55,181**	$ 33,923	$ 113,874
Acquisition of marketable securities as proceeds from sale of Argentina business unit (Note 4)	**$ —**	$ —	$ 13,912

See Note 3 in these consolidated financial statements for disclosure regarding shares issued in connection with the Company's acquisition of Petroamerica.

17. Subsequent Event

On February, 6, 2017, Gran Tierra announced that a purchase and sale agreement (the "Agreement") had been executed by the Purchaser to purchase Gran Tierra's Brazil business unit through the acquisition of all of the equity interests in one of Gran Tierra's indirect subsidiaries, and the assignment of certain debt owed by the corporate entities comprising Gran Tierra's Brazil business unit to the Gran Tierra group of companies (the "Brazil Divestiture").

Upon completion of the Brazil Divestiture, the Purchaser will acquire all of Gran Tierra's assets and certain liabilities in Brazil, including its 100% working interest in the Tiê Field and all of Gran Tierra's interest in exploration rights and obligations held pursuant to concession agreements granted by the Agência Nacional do Petróleo, Gás Natural e Biocombustíveis of Brazil ("ANP").

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

The economic effective date of the transaction will be on or before August 1, 2017, and Gran Tierra will continue to operate its Brazil business unit until the completion of the Brazil Divestiture.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

In accordance with Financial Accounting Standards Board (FASB) Accounting Standards Codification Topic 932, "Extractive Activities—Oil and Gas," and regulations of the U.S. Securities and Exchange Commission (SEC), the Company is making certain supplemental disclosures about its oil and gas exploration and production operations.

A. Estimated Proved NAR Reserves

The following table sets forth Gran Tierra's estimated proved NAR reserves and total net proved developed and undeveloped reserves as of December 31, 2013, 2014, 2015 and 2016, and the changes in total net proved reserves during the three-year period ended December 31, 2016.

The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and 100% of the reserves at December 31, 2016, have been evaluated by independent qualified reserves consultants, McDaniel & Associates Consultants Ltd.

The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end. The determination of oil and natural gas reserves is complex and requires significant judgment. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. "Risk Factors". See "Critical Accounting Estimates" in Item 7 for a description of Gran Tierra's reserves estimation process.

	Colombia		Argentina		Brazil		Total	
	Liquids [(1)] (Mbbl)	Gas (MMcf)	Liquids [(1)] (Mbbl)	Gas (MMcf)	Liquids [(1)] (Mbbl)	Gas (MMcf)	Liquids [(1)] (Mbbl)	Gas (MMcf)
Proved NAR Reserves, December 31, 2013	34,559	8,776	3,604	4,677	1,683	—	39,846	13,453
Extensions and discoveries	4,099	—	—	—	572	—	4,671	—
Production	(6,654)	(329)	(385)	(713)	(330)	—	(7,369)	(1,042)
Revisions of previous estimates	—	—	(3,219)	(3,964)	—	—	(3,219)	(3,964)
Revisions of Previous Estimates	2,040	(7,464)	—	—	911	—	2,951	(7,464)
Proved NAR Reserves, December 31, 2014	34,044	983	—	—	2,836	—	36,880	983
Extensions and discoveries	410	526	—	—	—	2,805	410	3,331
Improved recoveries	—	—	—	—	1,396	—	1,396	—
Production	(6,872)	(318)	—	—	(189)	—	(7,061)	(318)
Revisions of previous estimates	5,804	632	—	—	680	—	6,484	632
Proved NAR Reserves, December 31, 2015	**33,386**	**1,823**	**—**	**—**	**4,723**	**2,805**	**38,109**	**4,628**
Purchases of reserves in place	**20,568**	**—**	**—**	**—**	**—**	**—**	**20,568**	**—**
Extensions and discoveries	**1,142**	**435**	**—**	**—**	**—**	**—**	**1,142**	**435**
Production	**(8,125)**	**(592)**	**—**	**—**	**(262)**	**(2)**	**(8,387)**	**(594)**
Revisions of previous estimates	**(1,093)**	**(71)**	**—**	**—**	**1,591**	**783**	**498**	**712**
Proved NAR Reserves, December 31, 2016	**45,878**	**1,595**	**—**	**—**	**6,052**	**3,586**	**51,930**	**5,181**
Proved Developed Reserves, December 31, 2014	27,866	983	—	—	1,333	—	29,199	983
Proved Developed Reserves NAR, December 31, 2015	28,513	1,346	—	—	2,303	1,368	30,816	2,714
Proved Developed Reserves NAR, December 31, 2016	**35,529**	**1,468**	**—**	**—**	**1,912**	**1,382**	**37,441**	**2,850**
Proved Undeveloped Reserves NAR, December 31, 2014	6,178	—	—	—	1,503	—	7,681	—
Proved Undeveloped Reserves NAR, December 31, 2015	4,873	477	—	—	2,420	1,437	7,293	1,914
Proved Undeveloped Reserves NAR, December 31, 2016	**10,349**	**127**	**—**	**—**	**4,140**	**2,203**	**14,489**	**2,330**

[(1)] At December 31, 2016, 2015 and 2014, liquids reserves are 100% oil. At December 31, 2013, the Company had NGL reserves in small amounts in Colombia and Argentina only.

B. Capitalized Costs

Capitalized costs for Gran Tierra's oil and gas producing activities consisted of the following at the end of each of the years in the two-year period ended December 31, 2016:

(Thousands of U.S. Dollars)	Proved Properties	Unproved Properties	Accumulated Depletion, Depreciation and Impairment	Net Capitalized Costs
Colombia	**$ 2,435,124**	**$ 561,463**	**$ (2,059,073)**	**$ 937,514**
Brazil	**217,047**	**18,445**	**(180,779)**	**54,713**
Peru	**—**	**67,866**	**—**	**67,866**
Balance, December 31, 2016	**$ 2,652,171**	**$ 647,774**	**$ (2,239,852)**	**$ 1,060,093**
Colombia	$ 1,846,522	$ 147,500	$ (1,422,617)	$ 571,405
Brazil	151,808	69,089	(106,124)	114,773
Peru	—	94,182	—	94,182
Balance, December 31, 2015	$ 1,998,330	$ 310,771	$ (1,528,741)	$ 780,360

C. Costs Incurred

The following tables present costs incurred for Gran Tierra's oil and gas property acquisitions, exploration and development for the respective years:

(Thousands of U.S. Dollars)	Colombia	Argentina	Brazil	Peru	Total
Balance, December 31, 2013	$ 1,582,847	$ 274,976	$ 176,317	$ 221,405	$ 2,255,545
Property acquisition costs					
Proved	—	—	—	—	—
Unproved	—	—	—	—	—
Exploration costs	88,378	82	11,106	173,126	272,692
Development costs	124,307	18,179	12,983	—	155,469
Balance, December 31, 2014	1,795,532	293,237	200,406	394,531	2,683,706
Property acquisition costs					
Proved	—	—	—	—	—
Unproved	—	—	—	—	—
Exploration costs	17,512	—	12,466	50,347	80,325
Development costs	69,910	—	7,472	—	77,382
Balance, December 31, 2015	1,882,954	293,237	220,344	444,878	2,841,413
Property acquisition costs					
Proved	**408,793**	**—**	**—**	**—**	**408,793**
Unproved	**500,081**	**—**	**—**	**—**	**500,081**
Exploration costs	**33,362**	**—**	**6,086**	**4,985**	**44,433**
Development costs	**72,601**	**—**	**9,060**	**—**	**81,661**
Balance, December 31, 2016	**$ 2,897,791**	**$ 293,237**	**$ 235,490**	**$ 449,863**	**$ 3,876,381**

D. Results of Operations for Oil and Gas Producing Activities

(Thousands of U.S. Dollars)	Colombia	Brazil	Peru	Total Continuing Operations	Argentina	Total
Year Ended December 31, 2016						
Oil and natural gas sales	**$ 280,872**	**$ 8,397**	**$ —**	**$ 289,269**	**$ —**	**$ 289,269**
Production costs	**(116,141)**	**(2,560)**	**—**	**(118,701)**	**—**	**(118,701)**
Exploration expenses	**—**	**—**	**—**	**—**	**—**	**—**
DD&A expenses	**(132,569)**	**(3,819)**	**(544)**	**(136,932)**	**—**	**(136,932)**
Asset Impairment	**(514,314)**	**(71,143)**	**(31,192)**	**(616,649)**		**(616,649)**
Income tax expense	**187,168**	**(674)**	**—**	**186,494**	**—**	**186,494**
Results of Operations	**$ (294,984)**	**$ (69,799)**	**$ (31,736)**	**$ (396,519)**	**$ —**	**$ (396,519)**
Year Ended December 31, 2015						
Oil and natural gas sales	$ 269,035	$ 6,976	$ —	$ 276,011	$ —	$ 276,011
Production costs	(109,406)	(6,363)	—	(115,769)	—	(115,769)
Exploration expenses	—	—	—	—	—	—
DD&A expenses	(167,701)	(6,183)	(789)	(174,673)	—	(174,673)
Asset Impairment	(235,069)	(46,933)	(41,916)	(323,918)	—	(323,918)
Income tax expense	102,014	(880)	—	101,134	—	101,134
Results of Operations	$ (141,127)	$ (53,383)	$ (42,705)	$ (237,215)	$ —	$ (237,215)
Year Ended December 31, 2014						
Oil and natural gas sales	$ 532,196	$ 27,202	$ —	$ 559,398	$ 31,938	$ 591,336
Production costs	(107,101)	(6,848)	—	(113,949)	(14,612)	(128,561)
Exploration expenses	—	—	—	—	—	—
DD&A expenses	(174,063)	(9,932)	(690)	(184,685)	(13,684)	(198,369)
Asset Impairment	—	—	(265,126)	(265,126)	—	(265,126)
Income tax expense	(125,171)	(844)	68	(125,947)	(1,458)	(127,405)
Results of Operations	$ 125,861	$ 9,578	$ (265,748)	$ (130,309)	$ 2,184	$ (128,125)

E. Standardized Measure of Discounted Future Net Cash Flows and Changes

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions to Gran Tierra's after royalty share of estimated annual future production from proved oil and gas reserves.

	Colombia	Brazil
Twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within the twelve month period		
2016	**$ 31.67**	**$ 31.42**
2015	$ 43.51	$ 37.72
2014	$ 87.55	$ 84.63
Weighted average production costs		
2016	**$ 15.42**	**$ 12.19**
2015	$ 12.11	$ 8.30
2014	$ 14.74	$ 11.24

Future development and production costs to be incurred in producing and further developing the proved reserves are based on year end cost indicators. Future income taxes are computed by applying year end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows. Discounted future net cash flows are calculated using 10% mid-year discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

The Company believes this information does not in any way reflect the current economic value of its oil and gas producing properties or the present value of their estimated future cash flows as:

- no economic value is attributed to probable and possible reserves;
- use of a 10% discount rate is arbitrary; and
- prices change constantly from the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period.

The standardized measure of discounted future net cash flows from Gran Tierra's estimated proved oil and gas reserves is as follows:

(Thousands of U.S. Dollars)	Colombia	Brazil	Total
December 31, 2016			
Future cash inflows	**$ 1,487,553**	**$ 195,476**	**$ 1,683,029**
Future production costs	**(803,208)**	**(85,262)**	**(888,470)**
Future development costs	**(94,131)**	**(23,975)**	**(118,106)**
Future asset retirement obligations	**(24,647)**	**(1,200)**	**(25,847)**
Future income tax expense	**(28,446)**	**(8,957)**	**(37,403)**
Future net cash flows	**537,121**	**76,082**	**613,203**
10% discount	**(117,263)**	**(43,235)**	**(160,498)**
Standardized Measure of Discounted Future Net Cash Flows	**$ 419,858**	**$ 32,847**	**$ 452,705**
December 31, 2015			
Future cash inflows	$ 1,486,828	$ 195,726	$ 1,682,554
Future production costs	(697,071)	(58,058)	(755,129)
Future development costs	(51,671)	(15,660)	(67,331)
Future asset retirement obligations	(15,096)	(1,200)	(16,296)
Future income tax expense	(196,981)	(17,361)	(214,342)
Future net cash flows	526,009	103,447	629,456
10% discount	(119,100)	(45,599)	(164,699)
Standardized Measure of Discounted Future Net Cash Flows	$ 406,909	$ 57,848	$ 464,757
December 31, 2014			
Future cash inflows	$ 3,020,286	$ 240,022	$ 3,260,308
Future production costs	(998,809)	(63,928)	(1,062,737)
Future development costs	(182,503)	(14,150)	(196,653)
Future asset retirement obligations	(16,410)	(3,500)	(19,910)
Future income tax expense	(558,048)	(20,554)	(578,602)
Future net cash flows	1,264,516	137,890	1,402,406
10% discount	(337,969)	(43,304)	(381,273)
Standardized Measure of Discounted Future Net Cash Flows	$ 926,547	$ 94,586	$ 1,021,133

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following table summarizes changes in the standardized measure of discounted future net cash flows for Gran Tierra's proved oil and gas reserves during three years ended December 31, 2016:

(Thousands of U.S. Dollars)	2016	2015	2014
Balance, beginning of year	**$ 464,757**	$ 1,021,133	$ 1,344,953
Sales and transfers of oil and gas produced, net of production costs	**(207,776)**	(160,242)	(444,358)
Net changes in prices and production costs related to future production	**13,425**	(918,746)	(40,162)
Extensions, discoveries and improved recovery, less related costs	**111**	22,754	152,426
Previously estimated development costs incurred during the year	**34,917**	54,904	107,842
Revisions of previous quantity estimates	**(263,713)**	144,603	103,359
Accretion of discount	**73,076**	137,853	180,787
Purchases of reserves in place	**186,393**	—	—
Sales of reserves in place	**—**	—	(72,089)
Net change in income taxes	**178,273**	100,587	(256,033)
Changes in future development costs	**(26,758)**	61,911	(55,592)
Net decrease	**(12,052)**	(556,376)	(323,820)
Balance, end of year	**$ 452,705**	$ 464,757	$ 1,021,133

2) Summarized Quarterly Financial Information

(Thousands of U.S. Dollars, Except Per Share Amounts)	Three Months Ended March 31, 2016	June 30, 2016	September 30, 2016	December 31, 2016	Year Ended December 31, 2016
Oil and natural gas sales	**$ 57,403**	**$ 71,713**	**$ 68,539**	**$ 91,614**	**$ 289,269**
Asset impairment	**$ 56,898**	**$ 92,843**	**$ 319,974**	**$ 146,934**	**$ 616,649**
Net loss	**$ (45,032)**	**$ (63,559)**	**$ (229,619)**	**$ (127,355)**	**$ (465,565)**
Loss per share - Basic and Diluted	**$ (0.15)**	**$ (0.21)**	**$ (0.71)**	**$ (0.38)**	**$ (1.45)**

(Thousands of U.S. Dollars, Except Per Share Amounts)	Three Months Ended March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015	Year Ended December 31, 2015
Oil and natural gas sales	$ 76,231	$ 69,350	$ 75,653	$ 54,777	$ 276,011
Asset impairment	$ 37,014	$ 30,285	$ 149,979	$ 106,640	$ 323,918
Net loss	$ (44,866)	$ (38,564)	$ (101,877)	$ (82,722)	$ (268,029)
Loss per share - Basic and Diluted	$ (0.16)	$ (0.13)	$ (0.36)	$ (0.29)	$ (0.94)

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***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 Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as of December 31, 2016, to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting

Gran Tierra’s management is responsible for establishing and maintaining adequate internal control over financial reporting for Gran Tierra, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of Gran Tierra’s management, including our principal executive and principal financial officers, Gran Tierra conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013 (the “2013 COSO Framework”). Based on this evaluation under the 2013 COSO Framework, management concluded that its internal control over financial reporting was effective as of December 31, 2016. The effectiveness of Gran Tierra’s internal control over financial reporting as of December 31, 2016 has been audited by Deloitte LLP, independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2016, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Gran Tierra Energy Inc.

We have audited the internal control over financial reporting of Gran Tierra Energy Inc. and subsidiaries (the "Company") as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on the criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) and Canadian generally accepted auditing standards, the consolidated financial statements as of and for the year ended December 31, 2016 of the Company and our report dated February 28, 2017 expressed an unqualified opinion on those consolidated financial statements.

/s/ Deloitte LLP

Chartered Professional Accountants
February 28, 2017
Calgary, Canada

Item 9B. ***Other Information***

The Board of Directors of Gran Tierra Energy Inc. has established May 3, 2017, as the date of the Company's 2017 Annual Meeting of Stockholders (the "2017 Annual Meeting") and March 9, 2017, as the record date for determining stockholders entitled to notice of, and to vote at, the 2017 Annual Meeting. The time and location of the 2017 Annual Meeting will be as set forth in the Company's proxy materials for the 2017 Annual Meeting.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

The information required regarding our directors is incorporated herein by reference from the information contained in the section entitled "Proposal 1 - Election of Directors" in our definitive Proxy Statement for the 2017 Annual Meeting of Stockholders (our "Proxy Statement"), a copy of which will be filed with the SEC within 120 days after December 31, 2016. For information with respect to our executive officers, see "Executive Officers of the Registrant" at the end of Part I of this report, following Item 4.

The information required regarding Section 16(a) beneficial ownership reporting compliance is incorporated by reference from the information contained in the section entitled "Section 16(a) Beneficial Ownership Reporting Compliance" in our Proxy Statement.

The information required with respect to procedures by which security holders may recommend nominees to our Board of Directors, the composition of our Audit Committee, and whether we have an "audit committee financial expert", is incorporated by reference from the information contained in the section entitled "Proposal 1 - Election of Directors" in our Proxy Statement.

Adoption of Code of Ethics

Gran Tierra has adopted a Code of Business Conduct and Ethics (the "Code") applicable to all of its Board members, employees and executive officers, including its Chief Executive Officer (Principal Executive Officer), and Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer). Gran Tierra has made the Code available on its website at www.grantierra.com.

Gran Tierra intends to satisfy the public disclosure requirements regarding (1) any amendments to the Code, or (2) any waivers under the Code given to Gran Tierra's Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer by posting such information on its website at http://www.grantierra.com/corporate-responsibility.html. There were no amendments to the Code or waivers granted thereunder relating to the Principal Executive Officer, Principal Financial Officer or Principal Accounting Officer during 2016.

Item 11. ***Executive Compensation***

The information required regarding the compensation of our directors and executive officers is incorporated herein by reference from the information contained in the section entitled "Executive Compensation and Related Information" in our Proxy Statement, including under the subheadings "Director Compensation," "Compensation Committee Report" and "Compensation Committee Interlocks and Insider Participation".

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Security Ownership of Certain Beneficial Owners and Management

The information required regarding security ownership of our 10% or greater stockholders and of our directors and management is incorporated herein by reference from the information contained in the section entitled "Security Ownership of Certain Beneficial Owners and Management" in our Proxy Statement.

The following table provides certain information with respect to securities authorized for issuance under Gran Tierra's equity compensation plans in effect as of the end of December 31, 2016:

Equity Compensation Plan Information

Plan category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights [(1)]	(b) Weighted average exercise price of outstanding options, warrants and rights [(2)]	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a)[(3)]
Equity compensation plans approved by security holders	13,170,038	4.16	13,070,887
Equity compensation plans not approved by security holders	—	—	—
	13,170,038	4.16	13,070,887

(1) Includes shares reserved to be issued pursuant to stock options, performance stock units, deferred share units and restricted stock units (the latter three of which may be settled in cash or in shares of our common stock, at our election) granted pursuant to the 2007 Equity Incentive Plan, which is an amendment and restatement of our 2005 Equity Incentive Plan.

(2) Exercise price is not applicable to restricted stock units and, as such, restricted stock units are excluded from this column.

(3) In accordance with Item 201(d) of Regulation S-K, the figure in this column represents the total number of shares of our common stock remaining available for issuance under our 2007 Equity Incentive Plan as of December 31, 2015, minus the awards reported in column (a), above. Note, pursuant to the terms of the 2007 Equity Incentive Plan, the pool of shares available for grant thereunder is not actually reduced until an award is settled in shares of our common stock (as opposed to reducing the pool at the time of grant). Note further, that the 2007 Equity Incentive Plan provides that the number of shares of our common stock reserved for issuance under the plan shall be reduced by: (i) one share for each share of common stock issued pursuant to a stock option or stock appreciation right and (ii) 1.55 shares for each share of our common stock issued pursuant to an any other type of award granted under the 2007 Equity Incentive Plan that is settled in shares of our common stock. Accordingly, the number of shares available for future awards under the 2007 Equity Incentive Plan may be different than the amount shown in this column.

The only equity compensation plan approved by our stockholders is our 2007 Equity Incentive Plan, which is an amendment and restatement of our 2005 Equity Plan.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

The information required regarding related transactions is incorporated herein by reference from the information contained in the section entitled “Certain Relationships and Related Transactions” and, with respect to director independence, the section entitled “Proposal 1 - Election of Directors”, in our Proxy Statement.

Item 14. ***Principal Accounting Fees and Services***

The information required is incorporated herein by reference from the information contained in the sections entitled “Principal Accountant Fees and Services” and “Pre-Approval Policies and Procedures” in the proposal entitled “Ratification of Selection of Independent Auditors” in our Proxy Statement.

PART IV

Item 15. ***Exhibits, Financial Statement Schedules***

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

The following documents are included as Part II, Item 8. of this Annual Report on Form 10-K:

	Page
Report of Independent Registered Public Accounting Firm	78
Consolidated Statements of Operations	79
Consolidated Balance Sheets	80
Consolidated Statements of Cash Flow	81
Consolidated Statements of Shareholders’ Equity	83
Notes to the Consolidated Financial Statements	84
Supplementary Data (Unaudited)	113

(2) Financial Statement Schedules

None.

(3) Exhibits

See the Exhibit Index which follows the signature page of this Annual Report on Form 10-K, which is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: February 28, 2017	/s/ Gary Guidry
	By: Gary Guidry
	President and Chief Executive Officer, Director
	(Principal Executive Officer)
Date: February 28, 2017	/s/ Ryan Ellson
	By: Ryan Ellson
	Chief Financial Officer
	(Principal Financial and Accounting Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Gary Guidry and Ryan Ellson, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Name	Title	Date
/s/ Gary Guidry Gary Guidry	President and Chief Executive Officer, Director (Principal Executive Officer)	February 28, 2017
/s/ Ryan Ellson Ryan Ellson	Chief Financial Officer (Principal Financial and Accounting Officer)	February 28, 2017
/s/ Peter Dey Peter Dey	Director	February 28, 2017
/s/ Evan Hazell Evan Hazell	Director	February 28, 2017
/s/ Robert B. Hodgins Robert B. Hodgins	Director	February 28, 2017
/s/ Ronald Royal Ronald Royal	Director	February 28, 2017
/s/ David P. Smith David P. Smith	Director	February 28, 2017
/s/ Brooke Wade Brooke Wade	Director	February 28, 2017

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1+	Arrangement Agreement, dated November 12, 2015, between Gran Tierra Energy Inc. and Petroamerica Oil Corp.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 18, 2015 (SEC File No. 001-34018).
2.2	Plan of Conversion, dated October 31, 2016.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.1	Certificate of Incorporation.	Incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.2	Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
4.1	Reference is made to Exhibits 3.1 to 3.2.	
4.2	Details of the Goldstrike Special Voting Share.	Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005, and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.3	Goldstrike Exchangeable Share Provisions.	Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005 and filed with the SEC on April 21, 2006 (SEC File No. 333-111656).
4.4	Provisions Attaching to the GTE–Solana Exchangeable Shares.	Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the SEC on October 14, 2008 (SEC File No. 001-34018).
4.5	Indenture related to the 5.00% Convertible Senior Notes due 2021, dated as of April 6, 2016, between Gran Tierra Energy Inc. and U.S. Bank National Association	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.6	Form of 5.00% Convertible Senior Notes due 2021.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
4.7	Subscription Receipt Agreement, dated July 8, 2016, by and between Gran Tierra Energy Inc. and Computershare Trust Company of Canada	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
4.8	Form of Registration Rights Agreement.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
10.1	Voting Exchange and Support Agreement by and between Goldstrike, Inc., 1203647 Alberta Inc., Gran Tierra Goldstrike Inc. and Olympia Trust Company dated as of November 10, 2005.	Incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (SEC File No. 333-111656).
10.2	Voting and Exchange Trust Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Exchangeco Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2008 (SEC File No. 001-34018).
10.3	Support Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Callco ULC and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on November 17, 2008 (SEC File No. 001-34018).

10.4	Purchase Agreement, dated as of March 31, 2016, by and between Gran Tierra Energy Inc. and Nomura Securities International, Inc., Dundee Securities Inc. and RBC Dominion Securities Inc.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
10.5 +	Share Purchase Agreement dated as of June 30, 2016, among Gran Tierra Energy International Holdings Ltd., Tribeca Oil & Gas Inc., Macquarie Bank Limited, Rorick Ventures Group Inc., as vendors, and PetroLatina Energy Limited.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on July 7, 2016 (SEC File No. 001-34018).
10.6	Amended and Restated 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2012 (SEC File No. 001-34018).
10.7	Form of Restricted Stock Unit Award Agreement Under the 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2013 (SEC File No. 001-34018).
10.8	Form of Option Agreement Under the 2007 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 7, 2013 (SEC File No. 001-34018).
10.9	Form of Indemnity Agreement. *	Incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 2, 2008 (SEC File No. 000-52594).
10.10	Form of Voting Support Agreement	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 18, 2015 (SEC File No. 001-34018).
10.11	2005 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.11 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (SEC File No. 333-111656).
10.12	Executive Employment Agreement, dated January 20, 2010, between Gran Tierra Energy Inc. and David Hardy. *	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 (SEC File No. 001-34018).
10.13	Amendment to Employment Agreement dated May 2, 2012, between Gran Tierra Energy Inc. and David Hardy. *	Incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.14	Amendment dated January 10, 2014 to Expat Assignment Letter Agreement between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.80 to the Annual Report on Form 10-K, filed with the SEC on February 26, 2014 (SEC File No. 001-34018).
10.15	Amendment dated April 15, 2014 to Expat Assignment Letter Agreement between Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 7, 2014 (SEC File No. 001-34018).
10.16	Executive Employment Agreement dated July 31, 2014, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale. *	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on August 7, 2014 (SEC File No. 001-34018).
10.17	Expat Assignment Letter Agreement dated December 7, 2010, between Gran Tierra Energy Inc. and Duncan Nightingale.*	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on November 8, 2011 (SEC File No. 0001-34018).
10.18	Employment Agreement dated July 31, 2014, between Gran Tierra Energy Colombia Ltd. and Adrián Santiago Coral Pantoja. *	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on August 7, 2014 (SEC File No. 001-34018).
10.19	Amendment to Executive Employment Agreement dated February 19, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale.*	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 7, 2015 (SEC File No. 001-34018).

10.20	Amendment No. 2 to Executive Employment Agreement dated May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Duncan Nightingale.*	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.21	Amendment No. 2 to Executive Employment Agreement dated May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and David Hardy.*	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.22	Form of Indemnity Agreement for use with Directors and Executive Officers.*	Incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.23	Form of Deferred Stock Unit Award Agreement Under the 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K, filed with the SEC on February 29, 2016 (SEC File No. 001-34018).
10.24	Form of Deferred Stock Unit Grant Notice.*	Incorporated by reference to Exhibit 10.30 to the Annual Report on Form 10-K, filed with the SEC on February 29, 2016 (SEC File No. 001-34018).
10.25	Executive Employment Agreement effective May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Gary Guidry.*	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.26	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Ryan Ellson.*	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.27	Executive Employment Agreement effective May 11, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Alan Johnson.*	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.28	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Lawrence West.*	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.29	Executive Employment Agreement effective May 11, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and James Evans.*	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.30	Form of Performance Stock Unit Award Agreement Under the 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).
10.31	Form of Performance Stock Unit Grant Notice.*	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).
10.32	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Ryan Ellson.*	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).
10.33	Severance Agreement and Release dated April 6, 2016, between Gran Tierra Energy Inc. and Duncan Nightingale.*	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).
10.34	Executive Employment Agreement effective June 24, 2016, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Ed Caldwell.*	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on August 8, 2016 (SEC File No. 001-34018).
10.35	Executive Employment Agreement effective June 24, 2016, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Susan Mawdsley.*	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q, filed with the SEC on August 8, 2016 (SEC File No. 001-34018).
10.36	Executive Employment Agreement effective June 24, 2016, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Glen Mah.*	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on August 8, 2016 (SEC File No. 001-34018).

10.37	Executive Employment Agreement effective June 24, 2016, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Rodger Trimble.*	Incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q, filed with the SEC on August 8, 2016 (SEC File No. 001-34018).
10.38	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).
10.39	Credit Agreement, dated as of September 18, 2015, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on September 21, 2015 (SEC File No. 001-34018).
10.40	First Amendment to Credit Agreement, dated as of March 31, 2016, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., The Bank of Nova Scotia, and the lenders party thereto.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
10.41	Second Amendment to Credit Agreement, dated as of June 2, 2016, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., The Bank of Nova Scotia, and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on June 3, 2016 (SEC File No. 34018).
10.42	Third Amendment to Credit Agreement	Filed herewith.
10.43	Fourth Amendment to Credit Agreement, dated as of November 16, 2016, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Filed herewith.
10.44	Colombian Participation Agreement, dated as of June 22, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.55 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.45	Amendment No. 1 to Colombian Participation Agreement, dated as of November 1, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.56 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.46	Amendment No. 2 to Colombian Participation Agreement, dated as of July 3, 2008, between Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q/A, filed with the SEC on November 19, 2008 (SEC File No. 001-34018).
10.47	Amendment No. 3 to Participation Agreement, dated as of December 31, 2008, by and among Gran Tierra Energy Colombia, Ltd., Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 7, 2009 (SEC File No. 001-34018).
10.48	Amendment No. 4 dated June 13, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.49	Amendment No. 5 dated February 10, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).
10.50	Amendment No. 6 dated March 1, 2012, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 7, 2012 (SEC File No. 001-34018).

10.51	Chaza Block Hydrocarbons Exploration and Exploitation Agreement between Argosy Energy International and the National Hydrocarbons Agency dated June 25, 2005.	Incorporated by reference to Exhibit 10.76 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2013 (SEC File No. 001-34018).
10.52	Addendum No. 1 to the Chaza Block Hydrocarbons Exploration and Exploitation Agreement between Argosy Energy International and the National Hydrocarbons Agency.	Incorporated by reference to Exhibit 10.77 to the Annual Report on Form 10-K filed with the Securities and Exchange Commission on February 26, 2013 (SEC File No. 001-34018).
10.53	Settlement Agreement, dated May 7, 2015, between Gran Tierra Energy Inc. and West Face SPV (Cayman) I, L.P.	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2015 (SEC File No. 001-34018).
10.54	Bridge Loan Facility between Gran Tierra Energy Inc. and Scotiabank.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on August 29, 2016 (SEC File No. 001-34018).
12.1	Statement re: Computation of Ratio of Earnings to Fixed Charges.	Filed herewith.
21.1	List of subsidiaries.	Filed herewith.
23.1	Consent of Deloitte LLP.	Filed herewith.
23.2	Consent of McDaniel & Associates Consultants Ltd.	Filed herewith.
24.1	Power of Attorney.	See signature page.
31.1	Certification of Principal Executive Officer.	Filed herewith.
31.2	Certification of Principal Financial Officer.	Filed herewith.
32.1	Section 1350 Certifications.	Furnished herewith.
99.1	Gran Tierra Energy Inc. Reserves Assessment and Evaluation of Oil and Gas Properties Corporate Summary, effective December 31, 2016.	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.

* Management contract or compensatory plan or arrangement.

Exhibit 10.42

THIRD AMENDMENT TO CREDIT AGREEMENT

US 4456944v.13

This Third Amendment to Credit Agreement (this "Amendment") is entered into effective as of the 23rd day of August, 2016, by and among Gran Tierra Energy International Holdings Ltd., an exempted company incorporated with limited liability under the laws of the Cayman Islands (the "Borrower"), Gran Tierra Energy Inc., a corporation duly formed and existing under the laws of the State of Nevada (the "Parent"), The Bank of Nova Scotia, as administrative agent (the "Administrative Agent") and the Lenders party hereto.

W I T N E S S E T H:

WHEREAS, Borrower, the Parent, the Administrative Agent, and Lenders are parties to that certain Credit Agreement dated as of September 18, 2015 (as amended, supplemented or otherwise modified prior to the date hereof, the "Credit Agreement") (unless otherwise defined herein, all terms used herein with their initial letter capitalized shall have the meaning given such terms in the Credit Agreement as amended by this Amendment);

WHEREAS, pursuant to the Credit Agreement, Lenders have made certain Loans to the Borrower and provided certain other credit accommodations to Borrower;

WHEREAS, the Borrower has advised the Administrative Agent and the Lenders that the Borrower has entered into that certain Share Purchase Agreement, dated as of June 30, 2016 (the "Purchase Agreement"), by and among the Borrower, the "Vendors" (as defined in the Purchase Agreement) and Petrolatina Energy Limited, a company incorporated in England under the 1985 Act, with registered number 05173588 ("PELE"), pursuant to which the Borrower intends to acquire all of the "Purchased Securities" (as defined in the Purchase Agreement, herein, the "PELE Assets"), constituting all of the issued and outstanding Equity Interests of PELE;

WHEREAS, the Borrower has advised the Administrative Agent and the Lenders that the Borrower intends to finance the acquisition of the PELE Assets (the "PELE Acquisition") with (a) the proceeds of an issuance of common Equity Interests by the Parent generating Net Cash Proceeds of no less than $160.0 million (the "Equity Issuance"), (b) the proceeds of Revolving Credit Loans (the "Revolving Credit Borrowing"), (c) cash on hand (the "Cash Consideration") and (d) the proceeds of new term loans not to exceed $130.0 million (the "Term Loan Borrowing");

WHEREAS, the Borrower has requested that the Administrative Agent and the Lenders enter into this Amendment to amend the Credit Agreement to, among other things, provide for the issuance of Term Loans under the Credit Agreement on a *pari passu* basis with the Revolving Loans;

WHEREAS, the Administrative Agent, Borrower and the Lenders have agreed to enter into this Amendment to amend the Credit Agreement as more particularly set forth herein;

NOW THEREFORE, for and in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and confessed, Borrower, Administrative Agent and Lenders hereto hereby agree as follows:

Section 1. **Amendments**. In reliance on the representations, warranties, covenants and agreements contained in this Amendment, and subject to the satisfaction of the conditions precedent set forth in Section 2 hereof, the Credit Agreement and the exhibits to the Credit Agreement are, effective as of the Third Amendment Effective Date (as defined below), hereby amended to read in their entirety as attached as Exhibit A hereto.

SECTION 2. **Conditions Precedent**. This Amendment shall be effective on the date that each of the following conditions precedent is satisfied or waived in accordance with Section 12.02 of the Credit Agreement (the "Third Amendment Effective Date"):

2.1 **Counterparts**. Administrative Agent shall have received from the Lenders, the Parent and the Borrower, counterparts (in such number as may be requested by the Administrative Agent) of this Amendment signed on behalf of such Persons.

2.2 **Fees and Expenses**. The Borrower shall have paid to the Administrative Agent and the Lenders all fees required to be paid by the Borrower (including pursuant to that certain Fee Letter dated as of June 30, 2016 between the Parent and the Administrative Agent (the "Third Amendment Fee Letter"), and all expenses required to be paid by the Borrower under Section 12.03 of the Credit Agreement for which invoices have been presented at least 3 Business Days before the Third Amendment Effective Date (other than fees of counsel to the Administrative Agent).

2.3 **Acquisition Conditions**.

(a) The Administrative Agent shall have received a true and correct fully-executed copy of the Purchase Agreement (including all amendments, modifications, exhibits and schedules thereto) effecting the PELE Acquisition and other material side letters or agreements relating to the PELE Acquisition, and a certificate of an authorized officer of the Borrower certifying the same.

(b) Subject only to the funding of the Term Loans on the Third Amendment Effective Date, the PELE Acquisition shall have closed in accordance with the Purchase Agreement without giving effect to any waiver, modification or consent thereunder, or the failure to satisfy any condition in Section 6.1(a) thereof, that is materially adverse to the interests of the Lenders unless approved by the Administrative Agent (such approval not to be unreasonably withheld) (it being understood that (a) any such amendment or waiver that changes any third party beneficiary rights applicable to the Administrative Agent or the Lenders or the governing law provision or any increase in the amount of the purchase price under the Purchase Agreement (other than any increase in the amount of the purchase price paid in the form of, or funded with the proceeds of, common Equity Interests of the Parent) shall be deemed to be materially adverse to the interests of the Lenders and (b) any decrease in the amount of the purchase price under the Purchase Agreement of 10% or less shall be deemed not to be materially adverse to the interests of the Lenders) and the Administrative Agent shall have received a certificate of an authorized officer of the Borrower certifying the same.

(c) The Administrative Agent shall have received evidence that the Parent shall have received net proceeds from the Equity Issuance in an amount of no less than US$160.0 million which proceeds shall have been applied to the purchase price under the Purchase Agreement.

(d) After giving pro forma effect to the consummation of collectively, (i) the PELE Acquisition, (ii) the Equity Issuance, (iii) application of the Cash Consideration, (iv) the RBL Borrowing, (v) the borrowings of Term Loans under the Credit Agreement on the Third Amendment Effective Date and (vi) the payment of fees, commissions and expenses in connection with each of the foregoing (including pursuant to the Loan Documents (including the Third Amendment Fee Letter)) (collectively, the "Transactions") on the Third Amendment Effective Date, the Credit Parties shall have at least US$100.0 million of liquidity, comprised of borrowing capacity available under the Credit Agreement (but only to the extent that the Borrower is able to satisfy Section 6.02 of the Credit Agreement on such date) and cash not subject to a Lien (other than Liens securing the Secured Obligations).

(e) The Administrative Agent shall have received the Parent's unaudited financial statements for the fiscal quarter ending March 31, 2016.

(f) The Administrative Agent shall have received a pro forma consolidated balance sheet and related pro forma consolidated statements of income of the Parent as of and for the twelve-month period ending on the last day of the most recently completed four-fiscal quarter period ending March 31, 2016, prepared after giving effect to the Transactions as if the Transactions had occurred as of such date (in the case of such balance sheet) or at the beginning of such period (in the case of such other financial statements), in each case based on internal management information.

(g) The Administrative Agent shall have received a certificate of the Secretary, an Assistant Secretary or another officer of each Credit Party (a) setting forth (%4) resolutions of its board of directors or other applicable governing body with respect to the authorization of such Credit Party to execute and deliver this Third Amendment and the other Loan Documents to which it is a party and to enter into the transactions contemplated in those documents, (%4) the directors and/or officers of such Credit Party (y) who are authorized to sign the Loan Documents to which such Credit Party is a party and (z) who will, until removed from the board of directors or replaced by another officer or officers duly authorized for that purpose, act as its representative for the purposes of signing documents and giving notices and other communications in connection with this Agreement and the transactions contemplated hereby, (%4) specimen signatures of such authorized directors and/or officers, and (%4) the articles or certificate of incorporation and bylaws or memorandum and articles of association (or other organizational documents) of such Credit Party, certified as being true and complete or (b) certifying that (i) there have been no changes to any of the organizational documents of such Credit Party attached to the prior certificate of such Secretary, Assistant Secretary or other officer of such Credit Party and (ii) the resolutions of such Credit Party attached to such prior certificate remain in full force and effect and authorize the execution and delivery of this Third Amendment and the other Loan Documents to which such Credit Party is a party and its entry into the transactions contemplated by such documents.

(h) The Administrative Agent shall have received an opinion of (%4) Bracewell LLP, special New York counsel to the Parent and the other Credit Parties, in form and substance satisfactory to the Administrative Agent, (ii) Maples and Calder, Cayman Islands legal counsel to the Borrower, in form and substance satisfactory to the Administrative Agent (iii) Stikeman Elliott (London) LLP, special United Kingdom counsel to the Parent and the other Credit Parties, in form and substance satisfactory to the Administrative Agent, (iv) A&C Legal, special Colombian counsel to the Parent and the other Credit Parties, in form and substance satisfactory to the Administrative Agent, (v) Ventura Garcés & López-Ibor Abogados, special Spanish counsel to the Parent and the other Credit Parties, in form and substance satisfactory to the Administrative Agent, and (vi) Patton, Moreno & Asvat, special Panamanian counsel to the Parent and the other Credit Parties, in form and substance satisfactory to the Administrative Agent; and

(i) The Administrative Agent shall have received a certificate from a director of the Borrower in form and substance reasonably satisfactory to the Administrative Agent certifying that the Credit Parties, on a consolidated basis after giving effect to the Transactions and the other transactions contemplated hereby, are solvent.

(j) Each representation and warranty of Borrower contained in the Credit Agreement and the other Loan Documents is true and correct in all material respects (except to the extent any such representation or warranty is qualified by materiality or Material Adverse Effect, in which case it shall be true and correct in all respects) on the date hereof after giving effect to the amendments set forth herein, except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, such representations and warranties shall continue to be true and correct in all material respects (except to the extent any such representation or warranty is qualified by materiality or Material Adverse Effect, in which case it shall be true and correct in all respects) as of such specified earlier date.

(k) The Administrative Agent shall have received duly executed counterparts (in such number as may be requested by the Administrative Agent) signed by PELE and its Subsidiaries constituting Subsidiary Guarantors of an Assumption Agreement to that certain Guaranty and Collateral Agreement, dated as of September 18, 2015, by and among the Borrower, the Parent, the Administrative Agent, and the other parties thereto.

(l) The Administrative Agent shall have filed, or will file on the Effective Date, UCC-1 financing statements as the Administrative Agent may deem necessary or advisable to perfect the security interests created by the Security Instrument set forth in clause (k) above.

(m) The Administrative Agent shall have received (i) certificates, to the extent applicable, together with undated, blank stock powers or share transfer forms for each such certificate, representing all of the issued and outstanding Equity Interests of each Credit Party, other than PELE, and (ii) a share charge over the shares in PELE granted by the Borrower in favor of the Administrative Agent.

(n) The Administrative Agent shall have received duly executed Notes and Colombian Notes payable to each Lender in a principal amount equal to its Term Loan Commitment and Maximum Credit Amount dated as of the Third Amendment Effective Date.

(o) The Administrative Agent shall have received lien searches on PELE, all of its Subsidiaries and PELE's and such Subsidiaries' assets.

(p) Since December 31, 2015, there shall not have occurred any Target Material Adverse Change. "Target Material Adverse Change" means any change, event, occurrence, effect or circumstance that: (i) is or would reasonably be expected to be material and adverse to the business, condition (financial or otherwise), assets or results of operations of PELE and its Subsidiaries, taken as a whole, other than changes, effects, or circumstances resulting from or arising in connection with economic factors affecting the economy as a whole, or factors generally affecting the industry or specific markets in which PELE and its Subsidiaries operate or attributable to the announcement or performance of the transactions contemplated by the Purchase Agreement or the Additional Share Transactions (as defined in the Purchase Agreement), or both, situations of war or terrorism or changes in Applicable Law (as defined in the Purchase Agreement) or GAAP, provided that in each case, such matter does not have a materially disproportionate effect on any of PELE and its Subsidiaries, relative to other comparable companies and entities operating in the industries in which any of PELE and its Subsidiaries operates; or (B) would reasonably be expected to prevent or materially delay or impair the ability of any of the Vendors (as defined in the Purchase Agreement) to perform its obligations under the Purchase Agreement or to consummate the transactions contemplated therein.

(q) The Administrative Agent and the Lenders shall have received, to the extent requested by the Administrative Agent or such Lender at least 10 days prior to the Third Amendment Effective Date, all documentation and other information required by regulatory authorities under applicable 'know your customer" and anti-money laundering rules and regulations, including the Patriot Act, in respect of the Credit Parties after giving pro forma effect to the Transactions.

SECTION 3. **Representations and Warranties of Borrower**. To induce the Lenders and Administrative Agent to enter into this Amendment, Borrower hereby represents and warrants to Lenders and Administrative Agent as follows:

3.1 **Reaffirm Existing Representations and Warranties**. Each representation and warranty of Borrower contained in the Credit Agreement and the other Loan Documents is true and correct in all material respects (except to the extent any such representation or warranty is qualified by materiality or Material Adverse Effect, in which case it shall be true and correct in all respects) on the date hereof after giving effect to the amendments set forth herein, except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, such representations and warranties shall continue to be true and correct in all material respects (except to the extent any such representation or warranty is qualified by materiality or Material Adverse Effect, in which case it shall be true and correct in all respects) as of such specified earlier date.

3.2 **Due Authorization; No Conflict**. The execution, delivery and performance by Borrower of this Amendment are within Borrower's corporate powers and have been duly authorized by all necessary corporate and, if required, stockholder or shareholder action (including, without limitation, any action required to be taken by any class of directors of the Borrower or any other Person, whether interested or disinterested, in order to ensure the due authorization of this Amendment). The execution, delivery and performance by Borrower of this Amendment (a) do not require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority or any other third Person (including shareholders or any class of directors, whether interested or disinterested, of the Parent, the Borrower or any other Person), nor is any such consent, approval, registration, filing or other action necessary for the validity or enforceability of this Amendment, except such as have been obtained or made and are in full force and effect other than those third party approvals or consents which, if not made or obtained, would not cause a Default hereunder, could not reasonably be expected to have a Material Adverse Effect or do not have an adverse effect on the enforceability of this Amendment, (b) will not violate any applicable law or regulation or the charter, by-laws or other organizational documents of any Credit Party or any order of any Governmental Authority, (c) will not violate or result in a default under any Material Document or any indenture, agreement or other instrument binding upon Borrower or any other Credit Party or its Properties, or give rise to a right thereunder to require any payment to be made by any Credit Party, and (d) will not result in the creation or imposition of any Lien on any Property of Borrower or any other Credit Party (other than the Liens created by the Loan Documents).

3.3 **Validity and Enforceability**. This Amendment constitutes a legal, valid and binding obligation of Borrower, enforceable in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law.

3.4 **Acknowledgment of No Defenses**. Borrower acknowledges that it has no defense to (%3) Borrower's obligation to pay the Obligations when due, or (%3) the validity, enforceability or binding effect against Borrower or any other Credit Party of the Credit Agreement or any of the other Loan Documents (to the extent a party thereto) or any Liens intended to be created thereby.

SECTION 4. **Miscellaneous**.

4.1 **Reaffirmation of Loan Documents**. Any and all of the terms and provisions of the Credit Agreement and the Loan Documents shall, except as amended and modified hereby, remain in full force and effect. This Amendment shall not limit or impair any Liens securing the

Obligations, each of which are hereby ratified, affirmed and extended to secure the Obligations as it may be increased pursuant hereto. This Amendment constitutes a Loan Document.

4.2 **Parties in Interest**. All of the terms and provisions of this Amendment shall bind and inure to the benefit of the parties hereto and their respective successors and assigns.

4.3 **Counterparts**. This Amendment may be executed in counterparts, including, without limitation, by electronic signature, and all parties need not execute the same counterpart; however, no party shall be bound by this Amendment until each Credit Party and the Lenders have executed a counterpart. Facsimiles or other electronic transmissions (e.g. pdfs) of such executed counterparts shall be effective as originals.

4.4 **Complete Agreement**. THIS AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN OR AMONG THE PARTIES.

4.5 **Headings**. The headings, captions and arrangements used in this Amendment are, unless specified otherwise, for convenience only and shall not be deemed to limit, amplify or modify the terms of this Amendment, nor affect the meaning thereof.

4.6 **Effectiveness**. This Amendment shall be effective automatically and without necessity of any further action by Borrower, Administrative Agent or Lenders when counterparts hereof have been executed by each Credit Party and the Lenders.

4.7 **Governing Law**. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed by their respective authorized officers on the date and year first above written.

BORROWER: **GRAN TIERRA ENERGY INTERNATIONAL HOLDINGS LTD.**

By: /s/ Adrián Santiago Coral Pantoja

Name: Adrian Santiago Coral Pantoja

Title: Director

PARENT: **GRAN TIERRA ENERGY INC.**

By: /s/ Gary S. Guidry

Name: Gary S. Guidry

Title: President & C.E.O.

ADMINISTRATIVE AGENT: **THE BANK OF NOVA SCOTIA**,

By: /s/ Philip Lloyd

Name: Philip Lloyd

Title: Director, International Banking

By: /s/ Enrique Lopez

Name: Enrique Lopez

Title: Vice President, International Banking

LENDERS:

THE BANK OF NOVA SCOTIA, as a Lender

By: /s/ Philip Lloyd

Name: Philip Lloyd

Title: Director, International Banking

By: /s/ Enrique Lopez

Name: Enrique Lopez

Title: Vice President, International Banking

SOCIÉTÉ GÉNÉRALE,
as a Lender

By: /s/ Max Sonnonstine

Name: Max Sonnonstine

Title: Director

HSBC Bank Canada,

as a Lender

By: /s/ Jason Lang

Name: Jason Lang

Title: Director, Resources & Energy Group

By: /s/ Adam Lamb

Name: Adam Lamb

Title: Assistant Vice President,

Oil & Gas Large Corporate

Export Development Canada,

as a Lender

By: /s/ James Babbitt

Name: James Babbitt

Title: Principal, Extractive Industries/Structured and Project Finance

By: /s/ Frank Kelly

Name: Frank Kelly

Title: Director, Extractive Industries/Structured and Project Finance

Natixis, New York Branch,

as a Lender

By: /s/ Gabriela Davies

Name: Gabriela Davies

Title: Executive Director

By: /s/ Morvan Mallegol

Name: Morvan Mallegol

Title: Director

Royal Bank of Canada,

as a Lender

By: /s/ Bryn R. Davies

Name: Bryn R. Davies

Title: Authorized Signatory

Exhibit 10.43

FOURTH AMENDMENT TO CREDIT AGREEMENT

This Fourth Amendment to Credit Agreement (this "Amendment") is entered into effective as of the 16th day of November, 2016, by and among Gran Tierra Energy International Holdings Ltd., an exempted company incorporated with limited liability under the laws of the Cayman Islands ("Borrower"), Gran Tierra Energy Inc., a corporation duly formed and existing under the laws of the State of Delaware (f/k/a Gran Tierra Energy Inc., a corporation duly formed and existing under the laws of the State of Nevada, "Parent"), The Bank of Nova Scotia, as administrative agent ("Administrative Agent") and Lenders party hereto.

W I T N E S S E T H:

WHEREAS, Borrower, Parent, Administrative Agent, and Lenders are parties to that certain Credit Agreement dated as of September 18, 2015 (as amended, supplemented or otherwise modified prior to the date hereof, the "Credit Agreement") (unless otherwise defined herein, all terms used herein with their initial letter capitalized shall have the meaning given such terms in the Credit Agreement as amended by this Amendment);

WHEREAS, pursuant to the Credit Agreement, Lenders have made certain Loans to Borrower and provided certain other credit accommodations to Borrower;

WHEREAS, Borrower has advised Administrative Agent and Lenders that it intends to prepay the Term Loans in full;

WHEREAS, Borrower has requested that Administrative Agent and Lenders enter into this Amendment to amend the Credit Agreement to, among other things, delete Section 6.02 (e) of the Credit Agreement;

WHEREAS, Lenders have agreed to increase the Borrowing Base to $250,000,000.00, which redetermination of the Borrowing Base shall constitute the November 1, 2016 Scheduled Redetermination.

WHEREAS, Administrative Agent, Borrower and Lenders have agreed to enter into this Amendment to amend the Credit Agreement as more particularly set forth herein;

NOW THEREFORE, for and in consideration of the mutual covenants and agreements herein contained and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged and confessed, Borrower, Administrative Agent and Lenders hereto hereby agree as follows:

Section 1. **Amendments**. In reliance on the representations, warranties, covenants and agreements contained in this Amendment, and subject to the satisfaction of the conditions precedent set forth in Section 3 hereof, the Credit Agreement shall be amended, effective as of the Fourth Amendment Effective Date, as follows:

1.1 Global Amendment. Each reference in any Loan Document to "Gran Tierra Energy Inc., a corporation duly formed and existing under the laws of the State of Nevada" is hereby amended and restated in its entirety with "Gran Tierra Energy Inc., a corporation duly formed and existing under the laws of the State of Delaware".

1.2 Amendment to Section 6.02 of the Credit Agreement. Section 6.02 of the Credit Agreement is hereby amended by (a) deleting Section 6.02(e) of the Credit Agreement in its entirety and (b) amending and restating "and (e)." at the end of the last sentence of Section 6.02 of the Credit Agreement in its entirety with ".".

1.3 Amendment to Section 8.16 of the Credit Agreement. Section 8.16 of the Credit Agreement is hereby amended by (a) amending and restating Section 8.16(a)(vi) in its entirety with "[Reserved]." and (b) inserting new clause (c) of Section 8.16 as follows:

> (c) No later than December 21, 2016 (or such longer time as the Majority Lenders may agree), the Administrative Agent shall have received satisfactory evidence that the corporate resolutions of Taghmen approving the appointment of new directors of Taghmen by its sole shareholder have been duly registered with the Spanish Commercial Register.

1.4 Amendment to Section 9.02(e) of the Credit Agreement. Section 9.02(e) of the Credit Agreement shall be amended by amending and restating "percentage equal to the lesser of (x) the amount of the fraction expressed as a percentage, the numerator of which is the sum of the Revolving Credit Exposures of the Lenders on such day, and the denominator of which is $160,000,000 and (y) the Borrowing Base Utilization Percentage" with "Borrowing Base Utilization Percentage".

1.5 Amendment to Section 9.02(g) of the Credit Agreement. Section 9.02(g) of the Credit Agreement shall be amended by replacing "$150,000,000" in the first proviso with "$300,000,000".

1.6 Amendment to Section 9.02(i) of the Credit Agreement. Section 9.02(i) of the Credit Agreement shall be amended and restated in its entirety to read as follows:

> (i) Debt incurred by any Credit Party, the principal amount of which does not exceed five percent (5%) of the then-effective Borrowing Base in the aggregate.

1.7 Amendment to Sections 9.05(g) and 9.05(k) of the Credit Agreement. Sections 9.05(g) and 9.05(k) of the Credit Agreement shall be amended by amending and restating "percentage equal to the lesser of (x) the amount of the fraction expressed as a percentage, the numerator of which is the sum of the Revolving Credit Exposures of the Lenders on such day, and the denominator of which is $160,000,000 and (y) the Borrowing Base Utilization Percentage" with "Borrowing Base Utilization Percentage".

1.8 Amendment to Section 9.10 of the Credit Agreement. Section 9.10 of the Credit Agreement is hereby amended by (a) inserting "(as if such Credit Party had become a Subsidiary Guarantor as of such date)" immediately after "Section 8.14" therein, (b) deleting "and" immediately before clause (e) therein, (c) deleting "." at the end thereof and (d) inserting new clause (f) after clause (e) therein to read as follows:

> and (f) any Credit Party (other than the Borrower) may liquidate, wind up or dissolve if the Parent determines in good faith that such liquidation or dissolution is not materially disadvantageous to the Lenders and all of the assets of such Credit Party are transferred to another Credit Party.

1.9 Amendment to Section 12.02(b) of the Credit Agreement. Section 12.02(b) of the Credit Agreement is hereby amended by deleting "or Section 6.02(e)" therein in its entirety.

1.10 Amendment to Annex I of the Credit Agreement. Annex I of the Credit Agreement is hereby amended and restated in its entirety with Annex I attached hereto.

1.11 Amendment to Exhibit B of the Credit Agreement. Exhibit B of the Credit Agreement is hereby amended and restated in its entirety with Exhibit B attached hereto.

SECTION 2. **Redetermination of Borrowing Base**. Lenders hereby agree that for the period from and including the Fourth Amendment Effective Date, but until the next Scheduled Redetermination Effective Date, the next Interim Redetermination Date or the next adjustment to the Borrowing Base under Section 2.08(e), Section 2.08(f) or Section 9.11(d) of the Credit Agreement, whichever occurs first, the amount of the Borrowing Base shall be increased to $250,000,000.00, which redetermination of the Borrowing Base shall constitute the November 1, 2016 Scheduled Redetermination of the Borrowing Base. This Section 2 constitutes the New Borrowing Base Notice for the November 1, 2016 Scheduled Redetermination of the Borrowing Base.

SECTION 3. **Conditions Precedent**. This Amendment shall be effective on the date that each of the following conditions precedent is satisfied or waived in accordance with Section 12.02 of the Credit Agreement (the "Fourth Amendment Effective Date"):

3.1 **Prepayment of Term Loan**. Administrative Agent shall have received reasonably satisfactory evidence that the Term Loans have been indefeasibly prepaid in full in cash concurrently with the effectiveness of this Amendment on the Fourth Amendment Effective Date.

3.2 **Fee Letter**. The Borrower shall have paid to the Administrative Agent and the Lenders all fees required to be paid by the Borrower (including pursuant to that certain Fee Letter dated as of the date hereof between the Parent and the Administrative Agent (the "Fourth Amendment Fee Letter").

3.3 **Secretary's Certificate**. The Administrative Agent shall have received a certificate of the Secretary, an Assistant Secretary or another officer of the Parent setting forth (a) resolutions of its board of directors or other applicable governing body with respect to the authorization of the Parent to execute and deliver this Fourth Amendment, (b) the directors and/or officers of the Parent (i) who are authorized to sign the Loan Documents to which the Parent is a party and (ii) who will, until removed from the board of directors or replaced by another officer or officers duly authorized for that purpose, act as its representative for the purposes of signing documents and giving notices and other communications in connection with this Agreement and the transactions contemplated hereby, (c) specimen signatures of such authorized directors and/or officers, and (d) the articles or certificate of incorporation and bylaws or memorandum and articles of association (or other organizational documents) of the Parent, certified as being true and complete.

3.4 **Counterparts**. Administrative Agent shall have received from Lenders, Parent and Borrower, counterparts (in such number as may be requested by Administrative Agent) of this Amendment signed on behalf of such Persons.

3.5 **Expenses**. Borrower shall have paid to Administrative Agent any and all expenses payable to Administrative Agent (including counsel of Administrative Agent) or Lenders pursuant to or in connection with this Amendment or as required by the Credit Agreement.

3.6 **No Default/No Event of Default/No Borrowing Base Deficiency**. No Default or Event of Default shall have occurred and be continuing and no Borrowing Base Deficiency shall exist.

SECTION 4. **Reaffirmation of Loan Documents by Parent**. Parent hereby ratifies, confirms, and acknowledges that its obligations under the Credit Agreement and each other Loan Document are in full force and effect and that Parent continues to unconditionally and irrevocably, jointly and severally, guarantee the full and punctual payment, when due, whether at stated maturity or earlier by acceleration or otherwise, of all of the Secured Obligations, as such Secured Obligations may have been amended by this Amendment pursuant to the Guaranty Agreement. Parent hereby acknowledges that its execution and delivery of this Amendment does not indicate or establish an approval or consent requirement by Parent in connection with the execution and delivery of amendments to the Credit Agreement or any of the other Loan Documents.

SECTION 5. **Representations and Warranties of Parent and Borrower**. To induce Lenders and Administrative Agent to enter into this Amendment, Parent and Borrower each hereby represents and warrants to Lenders and Administrative Agent as follows:

5.1 **Reaffirm Existing Representations and Warranties**. Each representation and warranty of Parent or Borrower, as applicable, contained in the Credit Agreement and the other Loan Documents is true and correct in all material respects (except to the extent any such representation or warranty is qualified by materiality or Material Adverse Effect, in which case it shall be true and correct in all respects) on the date hereof after giving effect to the amendments set forth herein, except to the extent any such representations and warranties are expressly limited to an earlier date, in which case, such representations and warranties shall continue to be true and correct in all material respects (except to the extent any such representation or warranty is qualified by materiality or Material Adverse Effect, in which case it shall be true and correct in all respects) as of such specified earlier date.

5.2 **Due Authorization; No Conflict**. The execution, delivery and performance by Parent and Borrower of this Amendment are within Parent's or Borrower's, as applicable, corporate powers and have been duly authorized by all necessary corporate and, if required, stockholder or shareholder action (including, without limitation, any action required to be taken by any class of directors of Parent or Borrower or any other Person, whether interested or disinterested, in order to ensure the due authorization of this Amendment). The execution, delivery and performance by Parent and Borrower of this Amendment (a) do not require any consent or approval of, registration or filing with, or any other action by, any Governmental Authority or any other third Person (including shareholders or any class of directors, whether interested or disinterested, of Parent, Borrower or any other Person), nor is any such consent, approval, registration, filing or other action necessary for the validity or enforceability of this Amendment, except such as have been obtained or made and are in full force and effect other than those third party approvals or consents which, if not made or obtained, would not cause a Default hereunder, could not reasonably be expected to have a Material Adverse Effect or do not have an adverse effect on the enforceability of this Amendment, (b) will not violate any applicable law or regulation or the charter, by-laws or other organizational documents of any Credit Party or any order of any Governmental Authority, (c) will not violate or result in a default under any Material Document or any indenture, agreement or other instrument binding upon Borrower or any other Credit Party or its Properties, or give rise to a right thereunder to require any payment to be made by any Credit Party, and (d) will not result in the creation or imposition of any Lien on any Property of Borrower or any other Credit Party (other than the Liens created by the Loan Documents).

5.3 **Validity and Enforceability**. This Amendment constitutes a legal, valid and binding obligation of Parent and Borrower, enforceable in accordance with its terms, subject to applicable bankruptcy, insolvency, reorganization, moratorium or other laws affecting creditors' rights generally and subject to general principles of equity, regardless of whether considered in a proceeding in equity or at law.

5.4 **Acknowledgment of No Defenses**. Parent and Borrower each acknowledges that it has no defense to (%3) Borrower's obligation to pay the Obligations when due, or (%3) the validity, enforceability or binding effect against Borrower or any other Credit Party of the Credit Agreement or any of the other Loan Documents (to the extent a party thereto) or any Liens intended to be created thereby.

SECTION 6. **Miscellaneous**.

6.1 **Reaffirmation of Loan Documents**. Any and all of the terms and provisions of the Credit Agreement and the Loan Documents shall, except as amended and modified hereby, remain in full force and effect. This Amendment shall not limit or impair any Liens securing the Obligations, each of which are hereby ratified, affirmed and extended to secure the Obligations as it may be increased pursuant hereto. This Amendment constitutes a Loan Document.

6.2 **Parties in Interest**. All of the terms and provisions of this Amendment shall bind and inure to the benefit of the parties hereto and their respective successors and assigns.

6.3 **Counterparts**. This Amendment may be executed in counterparts, including, without limitation, by electronic signature, and all parties need not execute the same counterpart; however, no party shall be bound by this Amendment until Borrower, Parent and Lenders have executed a counterpart. Facsimiles or other electronic transmissions (e.g. pdfs) of such executed counterparts shall be effective as originals.

6.4 **Complete Agreement**. THIS AMENDMENT, THE CREDIT AGREEMENT AND THE OTHER LOAN DOCUMENTS REPRESENT THE FINAL AGREEMENT BETWEEN THE PARTIES AND MAY NOT BE CONTRADICTED BY EVIDENCE OF PRIOR, CONTEMPORANEOUS OR ORAL AGREEMENTS OF THE PARTIES. THERE ARE NO UNWRITTEN ORAL AGREEMENTS BETWEEN OR AMONG THE PARTIES.

6.5 **Headings**. The headings, captions and arrangements used in this Amendment are, unless specified otherwise, for convenience only and shall not be deemed to limit, amplify or modify the terms of this Amendment, nor affect the meaning thereof.

6.6 **Effectiveness**. This Amendment shall be effective automatically and without necessity of any further action by Borrower, Administrative Agent or Lenders when counterparts hereof have been executed by Parent, Borrower and Lenders.

6.7 **Governing Law**. THIS AMENDMENT SHALL BE GOVERNED BY, AND CONSTRUED IN ACCORDANCE WITH, THE LAWS OF THE STATE OF NEW YORK.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be duly executed by their respective authorized officers on the date and year first above written.

BORROWER: **GRAN TIERRA ENERGY INTERNATIONAL HOLDINGS LTD.**

By: /s/ Adrian Coral

Name: Adrian Coral

Title: Director

PARENT: **GRAN TIERRA ENERGY INC.**

By: /s/ Ryan Ellson

Name: Ryan Ellson

Title: Chief Financial Officer

ADMINISTRATIVE AGENT: **THE BANK OF NOVA SCOTIA**,

By: /s/ Clement Yu

Name: Clement Yu

Title: Director

By: /s/ Ryan Moonilal

Name: Ryan Moonilal

Title: Analyst

LENDERS:

THE BANK OF NOVA SCOTIA, as a Lender

By: /s/ Philip Lloyd

Name: Philip Lloyd

Title: Director, International Banking

By: /s/ Enrique Lopez

Name: Enrique Lopez

Title: Vice President, International Banking

SOCIÉTÉ GÉNÉRALE,

as a Lender

By: /s/ Max Sonnonstine

Name: Max Sonnonstine

Title: Director

HSBC Bank Canada,

as a Lender

By: /s/ Jason Lang

Name: Jason Lang

Title: Director, Global Banking

By: /s/ Greg Gannett

Name: Greg Gannett

Title: Managing Director, Global Banking

Export Development Canada,

as a Lender

By: /s/ Trystan Glynn-Morris

Name: Trystan Glynn-Morris

Title: Senior Associate

Structured and Project Finance

By: /s/ Frank Kelly

Name: Frank Kelly

Title: Director, Extractive Industries

Structured and Project Finance

Natixis, New York Branch,

as a Lender

By: /s/ Morvan Mallegol

Name: Morvan Mallegol

Title: Director

By: /s/ Federico Fiorentini

Name: Federico Fiorentini

Title: Managing Director

Royal Bank of Canada,

as a Lender

By: /s/ Bryn Davies

Name: Bryn Davies

Title: Authorized Signatory

ANNEX I

List of Maximum Credit Amounts

Lender	Applicable Revolving Credit Percentage	Maximum Revolving Credit Amounts
The Bank of Nova Scotia	22.50%	$112,500,000.00
Société Générale	22.50%	$112,500,000.00
HSBC Bank Canada	17.50%	$87,500,000.00
Export Development Canada	15.00%	$75,000,000.00
Natixis, New York Branch	15.00%	$75,000,000.00
Royal Bank of Canada	7.50%	$37,500,000.00
TOTAL:	**100.00000000%**	**$500,000,000.00**

<u>EXHIBIT B</u>

FORM OF BORROWING REQUEST

[ ], 20[ ]

Gran Tierra Energy International Holdings Ltd., an exempted company duly incorporated with limited liability and existing under the laws of the Cayman Islands (the "<u>Borrower</u>"), pursuant to <u>Section 2.04</u> of the Credit Agreement dated as of September 18, 2015 (together with all amendments, restatements, supplements or other modifications thereto, the "<u>Credit Agreement</u>") among the Borrower, the Parent, The Bank of Nova Scotia, as Administrative Agent and the other agents and lenders (the "<u>Lenders</u>") which are or become parties thereto (unless otherwise defined herein, each capitalized term used herein is defined in the Credit Agreement), hereby requests a Borrowing of [the Term/a Revolving] Loan as follows:

(i) Aggregate amount of the requested Borrowing is $[ ];

(ii) Date of such Borrowing is [ ], 20[ ];

(iii) Requested Borrowing is to be [an ABR Borrowing] [a Eurodollar Borrowing];

(iv) [The initial Interest Period applicable thereto is [ ];] [*Applicable only to Eurodollar Borrowings*]

(v) Amount of Borrowing Base in effect on the date hereof is $[ ];

(vi) Total Revolving Credit Exposures on the date hereof (i.e., outstanding principal amount of Revolving Loans and total LC Exposure) are $];

(vii) *Pro forma* total Revolving Credit Exposures (after giving effect to any requested Borrowing of Revolving Loans on or prior to the Borrowing Date) are $[ ]; and

(viii) Location and number of the Borrower's account to which funds are to be disbursed, which shall comply with the requirements of <u>Section 2.06</u> of the Credit Agreement, is as follows:

[________________________]

[________________________]

[________________________]

[________________________]

[________________________]

The undersigned certifies that he/she is the [ ] of the Borrower, and that as such he/she is authorized to execute this certificate on behalf of the Borrower. The undersigned further certifies, represents and warrants on behalf of the Borrower that the Borrower is entitled to receive the requested Borrowing under the terms and conditions of the Credit Agreement.

At the time of and immediately after giving effect to the Borrowing of Revolving Loans or the issuance, amendment, renewal or extension of such Letter of Credit, as applicable set forth above, the Borrower together with the other Credit Parties shall not have any cash or cash equivalents (other than Excluded Cash) in excess of $35,000,000 in the aggregate.

GRAN TIERRA ENERGY INTERNATIONAL HOLDINGS LTD.

By:

Name:

Title:

Exhibit 12.1

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

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

	Year Ended December 31,				
	2016	**2015**	**2014**	**2013**	**2012**
Fixed charges					
Contractual interest and financing expenses	**$ 8,454**	$ —	$ —	$ —	$ —
Amortization of debt issuance costs	**5,691**	—	—	—	—
Interest portion of rental expense	**44**	31	18	21	27
Total fixed charges	**$ 14,189**	$ 31	$ 18	$ 21	$ 27
(Loss) income from continuing operations before tax	**$ (650,234)**	$ (368,088)	$ (17,134)	$ 309,284	$ 196,349
Fixed charges per above	**14,189**	31	18	21	27
	$ (636,045)	$ (368,057)	$ (17,116)	$ 309,305	$ 196,376
Ratio of earnings to fixed charges				14,729	7,273
Deficiency of earnings available to cover fixed charges	**$ (636,045)**	$ (368,057)	$ (17,116)		

EXHIBIT 21.1

SUBSIDIARIES OF GRAN TIERRA ENERGY INC.

The table below sets forth all subsidiaries of Gran Tierra Energy Inc. and the state or other jurisdiction of incorporation or organization of each as of February 23, 2017.

Subsidiary	Jurisdiction of Incorporation
Gran Tierra Callco ULC	Alberta, Canada
Gran Tierra Exchangeco Inc.	Alberta, Canada
1203647 Alberta Inc.	Alberta, Canada
Gran Tierra Goldstrike Inc.	Alberta, Canada
Petrolifera Petroleum (Colombia) Limited	Cayman Islands
Gran Tierra Energy Cayman Islands Inc.	Cayman Islands
Gran Tierra Energy Canada ULC	Alberta, Canada
Argosy Energy LLC	Delaware
Gran Tierra Energy Colombia, Ltd.	Utah (a limited partnership)
Gran Tierra Resources Limited	Alberta, Canada
Gran Tierra Energy International Holdings Ltd	Cayman Islands
Gran Tierra Energy International (Peru) Holdings B.V.	Curacao
Gran Tierra Energy Peru B.V.	Curacao
Gran Tierra Energy Peru S.R.L.	Peru
Petrolifera Petroleum Del Peru S.R.L.	Peru
Gran Tierra Luxembourg Holdings S.a.r.l.	Luxembourg
Gran Tierra Finance (Luxembourg) S.a.r.l.	Luxembourg
Gran Tierra Energy Brasil Ltda.	Brazil
Gran Tierra Brazco (Luxembourg) S.a.r.l.	Luxembourg
Gran Tierra Colombia Inc.	Cayman Islands
Suroco Energy Venezuela	Venezuela
Vetra Petroamerica P&G Corp.	Barbados
Southeast Investment Corporation	Panama
Gran Tierra (PUT-7) Limited	Cayman
Petrolatina Energy Limited	United Kingdom
Petrolatina (CA) Limited	United Kingdom
R.L. Petroleum Corp.	Panama
North Riding Inc.	Panama
Petroleos Del Norte S.A.	Colombia
Taghmen Colombia S.L.	Spain
Taghmen Argentina Limited	United Kingdom
Gran Tierra México Energy. S. de R.L. de C.V.	Mexico

EXHIBIT 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in Registration Statements Nos. 333-146815, 333-156994, 333-171122 and 333-183029, on Form S-8, and Registration Statement No. 333-212819 on Form S-3, of our reports dated February 28, 2017, relating to the consolidated financial statements of Gran Tierra Energy Inc. and subsidiaries and the effectiveness of Gran Tierra Energy Inc. and subsidiaries' internal control over financial reporting, appearing in this Annual Report on Form 10-K of Gran Tierra Energy Inc. for the year ended December 31, 2016.

/s/ Deloitte LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2017

EXHIBIT 23.2

Consent of Independent Reserve Engineers

Mr. Ryan Ellson
Chief Financial Officer
Gran Tierra Energy Inc. ("Gran Tierra")
900, 520 3 Avenue S.W.
Calgary, Alberta, Canada T2P 0R3

Re: Gran Tierra Registration Statement:
Form S-8 (Reg. Nos. 333-146815, 333-156994, 333-171122 and 333-183029)
Form S-3 (Reg. No. 333-212819)
Filed with the United States Securities Exchange Commission

Dear Mr. Ellson:

As the independent reserve engineers for Gran Tierra, McDaniel & Associates Consultants Ltd. ("McDaniel"), hereby confirms that it has granted and not withdrawn its consent to the filing of McDaniel reserve report and to the reference to McDaniel's evaluation of Gran Tierra's reserves as of December 31, 2016, in the form and context disclosed by Gran Tierra in its Form 10-K submission filed with the United States Securities and Exchange Commission on approximately February 28, 2017, for the period ending December 31, 2016, and to the incorporation by reference thereof in the registration statements listed above.

Please do not hesitate to contact us if you have any questions.

McDaniel & Associates Consultants Ltd.

/s/ Cam Boulton
Cam Boulton
Vice President

Dated: February 28, 2017
Calgary, Alberta
CANADA

EXHIBIT 31.1

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

I, Gary Guidry, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2017

/s/ Gary Guidry

By: Gary Guidry

President and Chief Executive Officer,
Director

(Principal Executive Officer)

EXHIBIT 31.2

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

I, Ryan Ellson, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 28, 2017	/s/ Ryan Ellson
	By: Ryan Ellson
	Chief Financial Officer
	(Principal Financial Officer)

EXHIBIT 32.1

Certification of Chief Executive Officer and Chief Financial Officer
Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(Section 1350, Chapter 63 of Title 18, United States Code)

Pursuant to the requirement set forth in Rule 13a-14(b) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") and Section 1350, Chapter 63 of Title 18 of the United States Code (18 U.S.C-§1350), each of Gary Guidry, President and Chief Executive Officer of Gran Tierra Energy Inc., a Nevada corporation (the "Company"), and Ryan Ellson, Chief Financial Officer of the Company, does hereby certify, to such officer's knowledge that:

The Annual Report on Form 10-K for the fiscal year ended December 31, 2016 (the "Form 10-K") to which this Certification is attached as Exhibit 32.1 fully complies with the requirements of Section 13(a) or 15(d) of the Exchange Act. The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, the undersigned have set their hands hereto as of the 28th day of February 2017.

/s/ Gary Guidry

By: Gary Guidry

President and Chief Executive Officer,
Director

/s/ Ryan Ellson

By: Ryan Ellson

Chief Financial Officer

The foregoing certification is being furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (Section 1350, Chapter 63 of Title 18, United States Code) and is not deemed filed with the Securities and Exchange Commission as part of the Form 10-K or as a separate disclosure document and is not to be incorporated by reference into any filing of the Company under the Securities Act of 1933, as amended, or the Exchange Act (whether made before or after the date of the Form 10-K), irrespective of any general incorporation language contained in such filing.

EXHIBIT 99.1

THIRD PARTY REPORT ON RESERVES

By McDaniel & Associates Consultants Ltd. ("McDaniel") - (Independent Qualified Reserves Evaluator)

This report is provided to satisfy the requirements contained in Item 1202(a)(8) of U.S. Securities and Exchange Commission Regulation S-K with respect to Gran Tierra Energy Inc,'s ("Gran Tierra") oil and gas reserves as at December 31, 2016, and to provide the qualifications of the technical person primarily responsible for overseeing the reserve estimation process**.**

The numbering of items below corresponds to the requirements set out in Item 1202(a)(8) of Regulation S-K. Terms to which a meaning is ascribed in *Regulation S-K* and *Regulation S-X* have the same meaning in this report.

i. We have prepared an independent estimate of the oil and gas reserves of Gran Tierra for the management and the board of directors of Gran Tierra. The primary purpose of our evaluation report was to provide estimates of reserves information in support of Gran Tierra's year-end reserves reporting requirements under US Securities Regulation S-K and for other internal business and financial needs of Gran Tierra.

ii. We estimated the reserves of Gran Tierra as at December 31, 2016. The completion date of our report is January 23, 2017.

iii. McDaniel evaluated 100% of the reserves of Gran Tierra.

The following table sets forth the net after royalty reserves of Gran Tierra:

Category	Crude Oil Mbbl	Natural Gas MMcf	Oil Equivalent MBOE (1)	Portion of Reserves Evaluated, %
Proved				
Developed				
Brazil	1,912	1,382	2,142	100
Colombia	35,529	1,468	35,774	100
Undeveloped				
Brazil	4,140	2,203	4,506	100
Colombia	10,349	127	10,370	100
Total Proved	51,930	5,180	52,792	100
Probable				
Developed				
Colombia	10,852	190	10,884	100
Undeveloped				
Brazil	1,649	962	1,809	100
Colombia	31,132	2,193	31,498	100
Total Probable	43,633	3,345	44,191	100
Possible				
Developed				
Colombia	12,613	504	12,697	100
Undeveloped				
Brazil	3,407	2,009	3,742	100
Colombia	46,935	1,411	47,170	100
Total Possible	62,955	3,924	63,609	100

(1) Oil equivalence factors: Crude Oil 1 bbl/bbl, Natural Gas 6 Mcf/bbl.

iv. As noted in item iii., our evaluation covered 100% of the reserves of Gran Tierra. The assumptions, methods and procedures followed in the evaluation reflect the standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") modified as necessary to conform to the standards under the U.S. Financial Accounting Standards Board policies (the "FASB Standards") and. the U.S. Securities and Exchange Commission Regulations ("SEC requirements").

Data used in our evaluation of Gran Tierra's reserves was obtained from regulatory agencies, public sources and from Gran Tierra personnel and Gran Tierra files. In the preparation of our report we have accepted as presented, and have relied, without independent verification, upon a variety of information furnished by Gran Tierra such as interests and burdens on properties, recent production volumes, product transportation and marketing and sales agreements, historical revenue, capital costs, operating expense data, budget forecasts and capital cost estimates and well data for recently drilled wells. If in the course of our evaluation, the validity or sufficiency of any material information was brought into question, we did not rely on such information until such concerns were resolved to our satisfaction.

Gran Tierra warranted in a representation letter to us that, to the best of its knowledge and belief, all data furnished to us was accurate in all material respects, and no material data relevant to our evaluation was omitted.

A field examination of the evaluated properties was not performed nor was it considered necessary for the purposes of our report.

In our opinion, estimates provided in our report have, in all material respects, been determined in accordance with the applicable industry standards, and results provided in our report and summarized herein are appropriate for inclusion in filings under Regulation S-K.

v. As required under SEC Regulation S-X, reserves are those quantities of oil and gas that are estimated to be economically producible under existing economic conditions. The primary economic assumptions relate to pricing, capital and operating costs, recoverable volumes and production forecasts.

As specified, in determining economic production, constant product benchmark prices are to be based on a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the effective date of our report unless prices are defined by contractual or other regulatory arrangements. The relevant benchmark prices for Gran Tierra's reserves is Brent Blend Crude Oil FOB North Sea at $42.92 USD/bbl.

The product prices that were used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as "differentials." The differentials used in the preparation of this report estimated from received price information provided by Gran Tierra.

The average realized prices for Gran Tierra's reserves in the report are:

Oil and NGLs (USD/bbl) - Colombia	$	31.67
Natural Gas (USD/Mcf) - Colombia	$	3.67
Light/Medium Oil (USD/bbl) - Brazil	$	31.42
Natural Gas (USD/Mcf) - Brazil	$	1.47

In our economic analysis, operating and capital costs are those costs estimated as applicable at the effective date of our report, with no future escalation. Where deemed appropriate, the capital costs and revised operating costs associated with the implementation of committed projects designed to modify specific field operations in the future may be included in economic projections. Capital costs used in this report were provided by Gran Tierra and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs were assigned to the abandonment of wells assigned reserves, including future wells.

Reserves were assigned by volumetric, material balance, decline analysis or analogy where considered appropriate. In many cases, where sufficient data were available, a combination of the methods were applied.

Test data and other related information were used to estimate the anticipated initial production rates for those wells or analogous locations. For reserves not yet on production, forecast sales were estimated to commence at an anticipated date furnished by Gran Tierra. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

vi.. Our report has been prepared assuming the continuation of existing regulatory and fiscal conditions subject to the guidance in the COGE Handbook and SEC regulations. Notwithstanding that Gran Tierra currently has regulatory approval to produce the reserves identified in our report, there is no assurance that changes in regulation will not occur; such changes, which cannot reliably be predicted, could impact Gran Tierra's ability to recover the estimated reserves.

vii. Oil and gas reserves estimates have an inherent degree of associated uncertainty the extent of which is affected by many factors. Reserves estimates will vary due to the limited and imprecise nature of data upon which the estimates of reserves are predicated. Moreover, the methods and data used in estimating reserves are often necessarily indirect or analogical in character rather than direct or deductive. Furthermore, the persons involved in the preparation of reserves estimates and associated information are required, in applying geosciences, petroleum engineering and evaluation principles, to make numerous unbiased judgments based upon their educational background, professional training, and professional experience. The extent and significance of the judgments to be made are, in themselves, sufficient to render reserves estimates inherently imprecise. Reserves estimates may change substantially as additional data becomes available and as economic conditions impacting oil and gas prices and costs change. Reserves estimates will also change over time due to other factors such as knowledge and technology, fiscal and economic conditions, contractual, statutory and regulatory provisions.

viii. In our opinion, the reserves information evaluated by us have, in all material respects, been determined in accordance with all appropriate data, assumptions, methods and procedures applicable for the filing of reserves information under U.S. SEC Regulation S-K. All methods and procedures we considered necessary under the circumstances to prepare the report were used.

ix. A summary of Gran Tierra's reserves evaluated by us is provided in item iii.

McDaniel is a private firm established in 1955 whose business is the provision of independent geological and engineering services to the petroleum industry. McDaniel is among the largest evaluation firms in North America with over 60 professional and technical support personnel. Mr. Boulton coordinated the evaluation and is a qualified, independent reserves evaluator as defined in COGE Handbook, and a registered Practicing Professional Engineer in the Province of Alberta. Mr. Boulton has over 10 years of experience in the evaluation of oil and gas reserves and resources and has been employed at McDaniel as an evaluator/auditor since 2006.

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Dated: January 23, 2017

/s/ Cam Boulton

Cam Boulton
Vice President

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Peter Dey
Independent

Evan Hazell
Independent

Ronald W. Royal
Independent

David Smith
Independent

Brooke Wade
Independent

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President and Chief Executive Officer

Ryan Ellson
Chief Financial Officer

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MATERIAL REQUESTS

Gran Tierra will supply a copy of this document, including financial statements and schedules, without charge, upon receiving a written request for these materials. Please submit your requests by email to: info@grantierra.com or by mail to:
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Gran Tierra's filings are also available on a website maintained by the Securities and Exchange Commission at www.sec.gov and on SEDAR at www.sedar.com.

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