GRAN TIERRA ENERGY INC.
Form 10-Q
August 07, 2014

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

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

For the quarterly period ended June 30, 2014

or

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

For the transition period from __________ to __________

Commission file number 001-34018

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

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

300, 625 11 Avenue S.W.
Calgary, Alberta, Canada T2R 0E1
(Address of principal executive offices, including zip code)
(403) 265-3221
(Registrant's telephone number, including area code)

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

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

Large accelerated filer x Accelerated filer o

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

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

On August 1, 2014, the following number of shares of the registrant's capital stock were outstanding: 275,234,547 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 4,534,127 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 5,712,479 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

Gran Tierra Energy Inc.

Quarterly Report on Form 10-Q

Six Months Ended June 30, 2014

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CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q, particularly in Item 2. “Management’s Discussion and Analysis of Financial Condition and Results of Operations,” includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). All statements other than statements of historical facts included in this Quarterly Report on Form 10-Q, including without limitation statements in the Management’s Discussion and Analysis of Financial Condition and Results of Operations, regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and those statements preceded by, followed by or that otherwise include the words “believe”, “expect”, “anticipate”, “intend”, “estimate”, “project”, “target”, “goal”, “plan”, “objective”, “should”, or similar expressions or these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part II, Item 1A “Risk Factors” in this Quarterly Report on Form 10-Q. The information included herein is given as of the filing date of this Form 10-Q with the Securities and Exchange Commission (“SEC”) and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Quarterly Report on Form 10-Q to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

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

bbl	barrel	Mcf	thousand cubic feet
Mbbl	thousand barrels	MMcf	million cubic feet
MMbbl	million barrels	Bcf	billion cubic feet
bopd	barrels of oil per day	MMBtu	million British thermal units
BOE	barrels of oil equivalent	NGL	natural gas liquids
MMBOE	million barrels of oil equivalent	NAR	net after royalty
BOEPD	barrels of oil equivalent per day		

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

NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

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

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

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

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

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

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

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

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

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

- Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and

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government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PART I - Financial Information

Item 1. Financial Statements

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
REVENUE AND OTHER INCOME				
Oil and natural gas sales	$147,888	$150,250	$298,993	$336,490
Interest income	638	324	1,388	671
	148,526	150,574	300,381	337,161
EXPENSES				
Operating	25,346	23,970	47,212	56,013
Depletion, depreciation, accretion and impairment	41,937	55,592	86,201	106,054
General and administrative	13,932	9,090	26,795	18,112
Foreign exchange loss (gain)	10,044	(12,622)	5,834	(18,979)
Financial instruments gain (Note 10)	(2,604)	—	(5,013)	—
Other loss (Notes 9 and 10)	—	—	—	4,400
	88,655	76,030	161,029	165,600
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	59,871	74,544	139,352	171,561
Income tax expense (Note 8)	(28,387)	(24,960)	(58,096)	(61,977)
INCOME FROM CONTINUING OPERATIONS	31,484	49,584	81,256	109,584
Loss from discontinued operations, net of income taxes (Note 3)	(22,347)	(1,801)	(26,990)	(3,888)
NET INCOME AND COMPREHENSIVE INCOME	9,137	47,783	54,266	105,696
RETAINED EARNINGS, BEGINNING OF PERIOD	456,090	342,586	410,961	284,673
RETAINED EARNINGS, END OF PERIOD	$465,227	$390,369	$465,227	$390,369
INCOME (LOSS) PER SHARE				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$0.11	$0.18	$0.29	$0.38
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(0.08)	(0.01)	(0.10)	(0.01)
NET INCOME	$0.03	$0.17	$0.19	$0.37
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$0.11	$0.18	$0.28	$0.38
LOSS FROM DISCONTINUED OPERATIONS, NET OF INCOME TAXES	(0.08)	(0.01)	(0.09)	(0.01)
NET INCOME	$0.03	$0.17	$0.19	$0.37
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	283,773,204	282,822,383	283,505,690	282,482,343
	287,856,959	285,449,708	288,338,698	285,646,763

WEIGHTED AVERAGE SHARES
OUTSTANDING - DILUTED (Note 6)

(See notes to the condensed consolidated financial statements)

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

	June 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$332,359	$428,800
Restricted cash	855	1,478
Accounts receivable	111,182	49,703
Marketable securities (Note 10)	14,251	—
Other financial instruments (Note 10)	12	—
Inventory (Note 5)	25,410	13,725
Taxes receivable	14,998	9,980
Prepaids	4,362	6,450
Deferred tax assets (Note 8)	1,364	2,256
Total Current Assets	504,793	512,392
Oil and Gas Properties (using the full cost method of accounting)		
Proved	760,483	794,069
Unproved	479,075	456,001
Total Oil and Gas Properties	1,239,558	1,250,070
Other capital assets	9,118	10,102
Total Property, Plant and Equipment (Note 5)	1,248,676	1,260,172
Other Long-Term Assets		
Restricted cash	2,571	2,300
Deferred tax assets (Note 8)	1,438	1,407
Taxes receivable	10,907	18,535
Other long-term assets	7,037	7,163
Goodwill	102,581	102,581
Total Other Long-Term Assets	124,534	131,986
Total Assets	$1,878,003	$1,904,550
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts payable	$58,352	$72,400
Accrued liabilities	98,730	89,567
Taxes payable	13,455	102,887
Deferred tax liabilities (Note 8)	1,317	1,193
Asset retirement obligation (Note 7)	4,895	518
Total Current Liabilities	176,749	266,565
Long-Term Liabilities		
Deferred tax liabilities (Note 8)	179,504	177,082
Asset retirement obligation (Note 7)	15,206	21,455
Other long-term liabilities	11,394	9,540
Total Long-Term Liabilities	206,104	208,077
Contingencies (Note 9)		

Shareholders’ Equity		
Common Stock (Note 6) (274,821,285 and 272,327,810 shares of Common Stock and 10,395,144 and 10,882,440 exchangeable shares, par value $0.001 per share, issued and outstanding as at June 30, 2014, and December 31, 2013, respectively)	10,189	10,187
Additional paid in capital	1,019,734	1,008,760
Retained earnings	465,227	410,961
Total Shareholders’ Equity	1,495,150	1,429,908
Total Liabilities and Shareholders’ Equity	$1,878,003	$1,904,550

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30,	
	2014	2013
Operating Activities		
Net income	$54,266	$105,696
Adjustments to reconcile net income to net cash provided by operating activities:		
Loss from discontinued operations, net of income taxes (Note 3)	26,990	3,888
Depletion, depreciation, accretion and impairment	86,201	106,054
Deferred tax recovery (Note 8)	(841)	(15,715)
Non-cash stock-based compensation	2,624	4,110
Unrealized foreign exchange loss (gain)	4,567	(18,366)
Unrealized financial instruments gain	(351)	—
Equity tax	(1,642)	(1,718)
Other loss (Notes 9 and 10)	—	4,400
Net change in assets and liabilities from operating activities		
Accounts receivable and other long-term assets	(67,862)	(780)
Inventory	(9,348)	13,067
Prepaids	1,642	617
Accounts payable and accrued and other liabilities	9,747	(9,083)
Taxes receivable and payable	(77,306)	37,660
Net cash provided by operating activities of continuing operations	28,687	229,830
Net cash (used in) provided by operating activities of discontinued operations	(4,792)	18,950
Net cash provided by operating activities	23,895	248,780
Investing Activities		
Decrease (increase) in restricted cash	351	(4,285)
Additions to property, plant and equipment	(158,171)	(169,354)
Proceeds from sale of Argentina business unit, net of cash sold and transaction costs	42,755	—
Proceeds from sale of oil and gas properties (Note 5)	—	1,500
Net cash used in investing activities of continuing operations	(115,065)	(172,139)
Net cash used in investing activities of discontinued operations	(12,384)	(10,300)
Net cash used in investing activities	(127,449)	(182,439)
Financing Activities		
Proceeds from issuance of shares of Common Stock (Note 6)	7,113	3,013
Net cash provided by financing activities	7,113	3,013
Net (decrease) increase in cash and cash equivalents	(96,441)	69,354
Cash and cash equivalents, beginning of period	428,800	212,624
Cash and cash equivalents, end of period	$332,359	$281,978
Cash	$300,415	$279,377
Term deposits	31,944	2,601
Cash and cash equivalents, end of period	$332,359	$281,978

Supplemental cash flow disclosures:		
Cash paid for income taxes	$124,882	$12,631
Non-cash investing activities:		
Net liabilities related to property, plant and equipment, end of period	$76,506	$62,377

(See notes to the condensed consolidated financial statements)

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

	Six Months Ended June 30, 2014	Year Ended December 31, 2013
Share Capital		
Balance, beginning of period	$10,187	$7,986
Issue of shares of Common Stock (Note 6)	2	2,201
Balance, end of period	10,189	10,187
Additional Paid in Capital		
Balance, beginning of period	1,008,760	998,772
Exercise of stock options (Note 6)	7,111	1,570
Stock-based compensation (Note 6)	3,863	8,418
Balance, end of period	1,019,734	1,008,760
Retained Earnings		
Balance, beginning of period	410,961	284,673
Net income	54,266	126,288
Balance, end of period	465,227	410,961
Total Shareholders' Equity	$1,495,150	$1,429,908

(See notes to the condensed consolidated financial statements)

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

1. Description of Business

Gran Tierra Energy Inc., a Nevada corporation (the “Company” or “Gran Tierra”), is a publicly traded oil and gas company engaged in the acquisition, exploration, development and production of oil and natural gas properties. The Company’s principal business activities are in Colombia, Peru and Brazil. Until June 25, 2014, the Company also had business activities in Argentina (Note 3).

2. Significant Accounting Policies

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

The note disclosure requirements of annual consolidated financial statements provide additional disclosures to that required for interim unaudited condensed consolidated financial statements. Accordingly, these interim unaudited condensed consolidated financial statements should be read in conjunction with the Company’s consolidated financial statements as at and for the year ended December 31, 2013, included in the Company’s 2013 Annual Report on Form 10-K, filed with the Securities and Exchange Commission (“SEC”) on February 26, 2014.

The Company’s significant accounting policies are described in Note 2 of the consolidated financial statements which are included in the Company’s 2013 Annual Report on Form 10-K and are the same policies followed in these interim unaudited condensed consolidated financial statements, except as disclosed below. The Company has evaluated all subsequent events through to the date these interim unaudited condensed consolidated financial statements were issued.

Discontinued Operations

During the three months ended June 30, 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 interim unaudited condensed consolidated statement of operations for the three and six months ended June 30, 2014 and 2013, on a line immediately after “Income from continuing operations.” Amounts for 2013 have been reclassified to conform to the 2014 presentation. The reclassifications had no effect on net income. See Note 3, “Discontinued Operations,” for additional disclosure. The Company did not recognize depletion, depreciation and accretion expenses subsequent to May 29, 2014, the date the assets were classified as held for sale.

Marketable Securities

The Company acquired investments in marketable securities in connection with the sale of its Argentina business unit. Marketable securities were 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 statement of operations as financial instruments gains or losses.

Foreign Currency Derivatives

The Company purchases Colombian peso non-deliverable forward contracts for purposes of fixing exchange rates at which it will purchase Colombian pesos to settle its income tax installment payments (Note 10). The Company does not intend to issue or hold derivative financial instruments for speculative trading purposes.

The Company records derivative instruments on the balance sheet as either an asset or liability measured at fair value. The accounting for changes in the fair value of a derivative instrument depends on the intended use of the derivative and the resulting designation, which is established at the inception of a derivative. Generally because of the short-term nature of the contracts and their limited use, the Company does not apply hedge accounting, and changes in the fair value of those contracts are reflected in net income as financial instrument gains or losses in the interim unaudited condensed consolidated statement of operations. Cash settlements of the Company's derivative arrangements are classified as operating cash flows.

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

Recently Adopted Accounting Pronouncements

Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is fixed at the Reporting Date

In February 2013, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2013- 04, “Obligations Resulting from Joint and Several Liability Arrangements for Which the Total Amount of the Obligation is fixed at the Reporting Date”. The ASU provides guidance for the recognition, measurement, and disclosure of obligations resulting from joint and several liability arrangements for which the total amount of the obligation is fixed at the reporting date. Examples of obligations within the scope of this update include debt arrangements, other contractual obligations, and settled litigation and judicial rulings. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The implementation of this update did not materially impact the Company’s consolidated financial position, results of operations, cash flows or disclosure.

Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists

In July 2013, the FASB issued ASU 2013-11, “Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists". The ASU provides guidance on the financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. The ASU was effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The implementation of this update did not materially impact the Company’s consolidated financial position, results of operations, cash flows, or disclosure.

Recently Issued Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers". The ASU creates a single source of revenue guidance for all companies in all industries and requires revenue recognition to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 sets forth a new revenue recognition model that requires identifying the contract, identifying the performance obligations, determining the transaction price, allocating the transaction price to performance obligations and recognizing the revenue upon satisfaction of performance obligations. The amendments in the ASU can be applied either retrospectively to each prior reporting period presented or retrospectively with the cumulative effect of initially applying the update recognized at the date of the initial application along with additional disclosures. 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 the new standard will have on its consolidated financial position, results of operations, cash flows, and disclosure.

3. Discontinued Operations

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

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

Accordingly, the results of the Company's Argentina business unit are classified as "Loss from discontinued operations, net of income taxes" on the consolidated statements of operations for the three and six months ended June 30, 2014, and 2013. Amounts for 2013 have been reclassified to conform to the 2014 presentation. The reclassifications had no effect on net income.

Revenue and other income and loss from discontinued operations for the three and six months ended June 30, 2014, and 2013, were as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2014	2013	2014	2013
Revenue and other income	$ 14,161	$ 18,234	$ 31,985	$ 37,020
Loss from operations of discontinued operations before income taxes	$ (2,079)	$ (424)	$ (6,252)	$ (2,089)
Income tax expense	(988)	(1,377)	(1,458)	(1,799)
Loss from operations of discontinued operations	(3,067)	(1,801)	(7,710)	(3,888)
Loss on sale before income taxes	(18,235)	—	(18,235)	—
Income tax expense	(1,045)	—	(1,045)	—
Loss on sale	(19,280)	—	(19,280)	—
Loss from discontinued operations, net of income taxes	$ (22,347)	$ (1,801)	$ (26,990)	$ (3,888)

The Company did not meet the criteria to classify the Argentina business unit as held for sale at March 31, 2014, or prior periods. The cost center ceiling with respect to the Company's Argentina full cost pool exceeded the net capitalized cost of the cost center at March 31, 2014, and as such, no ceiling test writedown was required. In the year ended December 31, 2013, the Company recorded a ceiling test impairment loss of $30.8 million in the Company's Argentina cost center as a result of deferred investment and inconclusive waterflood results.

At December 31, 2013, assets and liabilities related to discontinued operations were as follows:

	As at
(Thousands of U.S. Dollars)	December 31, 2013
Current assets (1)	$ 39,125
Property, plant and equipment	94,446
Other long-term assets	1,839
	$ 135,410
Current liabilities	$ 37,612
Long-term liabilities	9,755
	$ 47,367

(1) Included cash of $21.2 million.

4. Segment and Geographic Reporting

The Company is primarily engaged in the exploration and production of oil and natural gas. The Company’s reportable segments are Colombia, Peru and Brazil based on geographic organization. Prior to classifying the Company’s Argentina business unit as discontinued operations (Note 3), Argentina was a reportable segment. The level of activity in Brazil was not significant at June 30, 2014, or December 31, 2013; however, the Company has separately disclosed its results of operations in Brazil as a reportable segment. The All Other category represents the Company’s corporate activities. The amounts disclosed in the tables below exclude the results of the Argentina business unit unless otherwise noted. Certain subsidiaries which were previously included in the All Other category were sold as part of the Argentina business unit, and therefore amounts disclosed in the All Other category have been reclassified to exclude amounts reported in loss from discontinued operations. The Company evaluates reportable segment performance based on income or loss from continuing operations before income taxes.

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

	Three Months Ended June 30, 2014				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$139,350	$—	$8,538	$—	$147,888
Interest income	184	—	434	20	638
Depletion, depreciation, accretion and impairment	39,348	103	2,241	245	41,937
Depletion, depreciation, accretion and impairment - per unit of production	26.14	—	25.12	—	26.30
Income (loss) from continuing operations before income taxes	62,481	(2,408)	3,750	(3,952)	59,871
Segment capital expenditures	45,688	41,912	3,433	306	91,339

	Three Months Ended June 30, 2013				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$144,333	$—	$5,917	$—	$150,250
Interest income	143	12	2	167	324
Depletion, depreciation, accretion and impairment	48,364	137	6,843	248	55,592
Depletion, depreciation, accretion and impairment - per unit of production	29.01	—	102.20	—	32.06
Income (loss) from continuing operations before income taxes	84,470	(2,353)	(2,887)	(4,686)	74,544
Segment capital expenditures (1)	48,743	19,601	19,981	228	88,553

	Six Months Ended June 30, 2014				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$284,285	$—	$14,708	$—	$298,993
Interest income	321	—	859	208	1,388
Depletion, depreciation, accretion and impairment	80,598	311	4,820	472	86,201
Depletion, depreciation, accretion and impairment - per unit of production	25.78	—	30.99	—	26.26
Income (loss) from continuing operations before income taxes	148,492	(4,466)	5,700	(10,374)	139,352
Segment capital expenditures	96,231	62,805	13,799	605	173,440

	Six Months Ended June 30, 2013				
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Peru	Brazil	All Other	Total
Oil and natural gas sales	$324,336	$—	$12,154	$—	$336,490
Interest income	304	26	11	330	671
Depletion, depreciation, accretion and impairment	94,320	199	11,014	521	106,054
Depletion, depreciation, accretion and impairment - per unit of production	27.63	—	84.21	—	29.92
Income (loss) from continuing operations before income taxes	186,138	(3,580)	(3,326)	(7,671)	171,561
Segment capital expenditures (1)	79,150	48,848	34,520	239	162,757

(1) In 2013, segment capital expenditures are net of proceeds of $1.5 million relating to the Company's sale of its 15% working interest in the Mecaya Block in Colombia (Note 5).

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	As at June 30, 2014						
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total Excluding Discontinued Operations	Discontinued Operations	Total
Property, plant and equipment	$861,331	$241,025	$143,226	$3,094	$1,248,676	$—	$1,248,676
Goodwill	102,581	—	—	—	102,581	—	102,581
All other assets	247,012	30,211	24,747	224,776	526,746	—	526,746
Total Assets	$1,210,924	$271,236	$167,973	$227,870	$1,878,003	$—	$1,878,003

	As at December 31, 2013						
(Thousands of U.S. Dollars)	Colombia	Peru	Brazil	All Other	Total Excluding Discontinued Operations	Discontinued Operations	Total
Property, plant and equipment	$850,359	$178,531	$133,874	$2,962	$1,165,726	$94,446	$1,260,172
Goodwill	102,581	—	—	—	102,581	—	102,581
All other assets	233,336	24,240	24,477	218,780	500,833	40,964	541,797
Total Assets	$1,186,276	$202,771	$158,351	$221,742	$1,769,140	$135,410	$1,904,550

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

In the six months ended June 30, 2014, the Company had two significant customers in Colombia: Ecopetrol S.A. ("Ecopetrol") and one other customer, which accounted for 52% and 38%, respectively, of the Company's consolidated oil and natural gas sales from continuing operations. For the three months ended June 30, 2014, these customers accounted for 54% and 33%, respectively, of the Company's consolidated oil and natural gas sales from continuing operations. For the three and six months ended June 30, 2013, sales to Ecopetrol accounted for 48% and 54% and sales to the other customer accounted for 44% and 32% respectively, of the Company's consolidated oil and natural gas sales from continuing operations.

5. Property, Plant and Equipment and Inventory

Property, Plant and Equipment

	As at June 30, 2014			As at December 31, 2013		
(Thousands of U.S. Dollars)	Cost	Accumulated depletion, depreciation and impairment	Net book value	Cost	Accumulated depletion, depreciation and impairment	Net book value
Oil and natural gas properties						
Proved	$1,870,800	$(1,110,317)	$760,483	$1,799,544	$(1,005,475)	$794,069
Unproved	479,075	—	479,075	456,001	—	456,001
	2,349,875	(1,110,317)	1,239,558	2,255,545	(1,005,475)	1,250,070

Furniture and fixtures and leasehold improvements	8,656	(6,567)	2,089	8,919	(6,568)	2,351
Computer equipment	12,954	(6,391)	6,563	14,786	(7,605)	7,181
Automobiles	802	(336)	466	1,381	(811)	570
Total Property, Plant and Equipment	$2,372,287	$(1,123,611)	$1,248,676	$2,280,631	$(1,020,459)	$1,260,172

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Depletion and depreciation expense from continuing operations on property, plant and equipment for the three months ended June 30, 2014, was $46.2 million (three months ended June 30, 2013 - $51.8 million) and for the six months ended June 30, 2014, was $90.5 million (six months ended June 30, 2013 - $98.8 million). A portion of depletion and depreciation expense was recorded as inventory in each period and adjusted for inventory changes. In the second quarter of 2013, the Company recorded a ceiling test impairment loss of $2.0 million in the Company's Brazil cost center as a result of lower realized prices and increased operating costs.

On August 6, 2014, the Company announced proved reserves, net after royalty and calculated in accordance with SEC rules as of May 31, 2014, for the Tiê field, in Brazil increased after production for the five months ended May 31, 2014, to 3.0 MMBOE from 1.7 MMBOE, proved and probable reserves increased to 4.9 MMBOE from 3.3 MMBOE and proved, probable and possible reserves increased to 7.2 MMBOE from 5.0 MMBOE. The reserve revisions were due to new production from the Agua Grande formation, results of seismic reprocessing, and additional reservoir volume in the Sergi formation.

In the second quarter of 2013, the Company received proceeds of $1.5 million relating to a sale of its 15% working interest in the Mecaya Block in Colombia.

In Brazil, the exploration phase of the concession agreements on Blocks REC-T-129, REC-T-142 and REC-T-155 were each due to expire on November 24, 2013, and the exploration phase of the concession agreement on Block REC-T-224 was due to expire on December 11, 2013; however, under the concession agreements the Company was able and did submit applications to the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") for extensions or suspensions of the exploration phases of these blocks. The Company has not yet received a decision from the ANP regarding these extension or suspension applications. At June 30, 2014, unproved properties included $59.0 million relating to exploration expenditures on these four blocks. Management assessed these blocks for impairment at June 30, 2014, and concluded no impairment had occurred.

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Peru and Brazil. As at June 30, 2014, the Company had $162.0 million (December 31, 2013 - $176.1 million) of unproved assets in Colombia, $239.8 million (December 31, 2013 - $177.5 million) of unproved assets in Peru, and $77.3 million (December 31, 2013 - $84.2 million) of unproved assets in Brazil for a total of $479.1 million (December 31, 2013 - $437.8 million). At December 31, 2013, the Company had $18.2 million of unproved assets in Argentina, which were sold as part of the sale of the Argentina business unit during the six months ended June 30, 2014 (Note 3). Unproved oil and natural gas properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration warrants whether or not future areas will be developed.

Inventory

At June 30, 2014, oil and supplies inventories were $23.0 million and $2.4 million, respectively (December 31, 2013 - $11.7 million and $2.0 million, respectively).

6. Share Capital

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

As at June 30, 2014, outstanding share capital consists of 274,821,285 shares of Common Stock of the Company, 5,861,017 exchangeable shares of Gran Tierra Exchangeco Inc., (the "Exchangeco exchangeable shares") and 4,534,127 exchangeable shares of Gran Tierra Goldstrike Inc. (the "Goldstrike exchangeable shares"). The redemption date for the Exchangeco exchangeable shares and the Goldstrike exchangeable shares is a date to be established by the applicable Board of Directors. During the six months ended June 30, 2014, 2,006,179 shares of Common Stock were issued upon the exercise of stock options and 487,296 shares of Common Stock were issued upon the exchange of the Exchangeco exchangeable shares.

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

Restricted Stock Units and Stock Options

The Company grants time-vested restricted stock units ("RSUs") to certain officers, employees and consultants. Additionally, the Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. The following table provides information about RSU and stock option activity for the six months ended June 30, 2014:

	RSUs Number of Outstanding Share Units	Options Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2013	922,045	15,668,458	5.41
Granted	843,455	2,246,775	7.09
Exercised	(409,931)	(2,006,179)	(3.55)
Forfeited	(32,516)	(138,532)	(6.55)
Expired	—	(140,318)	(6.92)
Balance, June 30, 2014	1,323,053	15,630,204	5.87

For the six months ended June 30, 2014, 2,006,179 shares of Common Stock were issued for cash proceeds of $7.1 million upon the exercise of 2,006,179 stock options (six months ended June 30, 2013 - $3.0 million).

The weighted average grant date fair value for options granted in the three months ended June 30, 2014, was $2.38 (three months ended June 30, 2013 - $2.66) and for the six months ended June 30, 2014, was $2.51 (six months ended June 30, 2013 - $2.65).

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

(Thousands of U.S. Dollars)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Compensation costs for stock options	$ 1,847	$ 1,932	$ 3,863	$ 4,181
Compensation costs for RSUs	2,397	619	3,641	619
	4,244	2,551	7,504	4,800
Less: stock-based compensation costs capitalized	(1,039)	(202)	(1,822)	(384)
Stock-based compensation costs expensed	$ 3,205	$ 2,349	$ 5,682	$ 4,416

Of the total compensation expense for the three months ended June 30, 2014, $2.0 million (three months ended June 30, 2013 - $2.0 million) was recorded in G&A expenses, $0.1 million (three months ended June 30, 2013 – $0.1 million) was recorded in operating expenses and $1.1 million (three months ended June 30, 2013 – $0.2 million) was recorded in loss from discontinued operations. Of the total compensation expense for the six months ended June 30, 2014, $4.1 million (six months ended June 30, 2013 – $3.8 million) was recorded in G&A expenses, $0.3 million (six months ended June 30, 2013 – $0.3 million) was recorded in operating expenses and $1.3 million (six months ended June 30, 2013 - $0.3 million) was recorded in loss from discontinued operations.

At June 30, 2014, there was $12.7 million (December 31, 2013 - $8.1 million) of unrecognized compensation cost related to unvested stock options and RSUs which is expected to be recognized over a weighted average period of 2.0 years. The vesting of certain RSUs and stock options was accelerated as a result of the sale of the Argentina business unit (Note 3).

Income per share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Weighted average number of common and exchangeable shares outstanding	283,773,204	282,822,383	283,505,690	282,482,343
Weighted average shares issuable pursuant to stock options	13,373,568	10,400,550	13,462,797	5,610,297
Weighted average shares assumed to be purchased from proceeds of stock options	(9,289,813)	(7,773,225)	(8,629,789)	(2,445,877)
Weighted average number of diluted common and exchangeable shares outstanding	287,856,959	285,449,708	288,338,698	285,646,763

For the three months ended June 30, 2014, 3,137,840 options (three months ended June 30, 2013 - 5,282,205 options) were excluded from the diluted income per share calculation as the options were anti-dilutive. For the six months ended June 30, 2014, 3,137,840 options (six months ended June 30, 2013 - 10,902,358 options) were excluded from the diluted income per share calculation as the options were anti-dilutive.

7. Asset Retirement Obligation

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

(Thousands of U.S. Dollars)	Six Months Ended June 30, 2014	Year Ended December 31, 2013
Balance, beginning of year	$21,973	$18,292
Settlements	—	(2,068)
Liability incurred	5,154	2,623
Liabilities associated with the Argentina business unit sold (Note 3)	(10,170)	—
Foreign exchange	7	(25)
Accretion	782	1,279
Revisions in estimated liability	2,355	1,872
Balance, end of period	$20,101	$21,973
Asset retirement obligation - current	$4,895	$518
Asset retirement obligation - long-term	15,206	21,455
Balance, end of period	$20,101	$21,973

Revisions to estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling the asset retirement obligation. At June 30, 2014, the fair value of assets that are legally restricted for purposes of settling the asset retirement obligation was $2.1 million (December 31, 2013 - $1.9 million). These assets are included in restricted cash on the Company's interim unaudited condensed balance sheet.

8. Taxes

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

	Six Months Ended June 30,	
(Thousands of U.S. Dollars)	2014	2013
Income (loss) from continuing operations before income taxes		
United States	$(10,791)	$(4,631)
Foreign	150,143	176,192
	139,352	171,561
	35 %	35 %
Income tax expense from continuing operations expected	48,773	60,046
Foreign currency translation adjustments	161	(5,262)
Impact of foreign taxes	(1,803)	(1,686)
Other local taxes	2,014	751
Stock-based compensation	1,397	1,043
Increase in valuation allowance	294	2,766
Non-deductible third party royalty in Colombia	4,505	5,749
Other permanent differences	2,755	(1,430)
Total income tax expense from continuing operations	$58,096	$61,977
Current income tax expense from continuing operations		
United States	$721	$726
Foreign	58,216	76,966
	58,937	77,692
Deferred income tax recovery from continuing operations		
Foreign	(841)	(15,715)
Total income tax expense from continuing operations	$58,096	$61,977

	As at	
(Thousands of U.S. Dollars)	June 30, 2014	December 31, 2013
Deferred Tax Assets		
Tax benefit of operating loss carryforwards	$35,780	$47,154
Tax basis in excess of book basis	42,412	59,168
Foreign tax credits and other accruals	18,142	34,894
Tax benefit of capital loss carryforwards	28,792	4,769
Deferred tax assets before valuation allowance	125,126	145,985
Valuation allowance	(122,324)	(142,322)
	$2,802	$3,663
Deferred tax assets - current	$1,364	$2,256
Deferred tax assets - long-term	1,438	1,407
	2,802	3,663
Deferred tax liabilities - current	(1,317)	(1,193)
Deferred tax liabilities - long-term	(179,504)	(177,082)
	(180,821)	(178,275)
Net Deferred Tax Liabilities	$(178,019)	$(174,612)

As at June 30, 2014, the Company had operating loss carryforwards of $118.7 million (December 31, 2013 - $215.4 million) and capital loss carryforwards of $224.7 million (December 31, 2013 – $32.6 million) before valuation allowance. Of these operating loss carryforwards and capital loss carryforwards, $304.5 million (December 31, 2013 - $213.8 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between

2014 and 2034 and the capital loss carryforwards expire between 2016 and 2017, while certain other jurisdictions allow operating and capital losses to be carried forward indefinitely.

As at June 30, 2014, the total amount of Gran Tierra's unrecognized tax benefit related to continuing operations was $4.0 million (December 31, 2013 - $2.9 million), which if recognized would affect the Company's effective tax rate. To the extent interest and penalties may be assessed by taxing authorities on any underpayment of income tax, such amounts have been accrued and are classified as a component of income taxes in the consolidated statement of operations.

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

	Six Months Ended June 30,	
	2014	2013
(Thousands of U.S. Dollars)		
Unrecognized tax benefit relating to continuing operations at beginning of period	$ 2,900	$ 5,900
Increases for positions relating to prior year	1,100	—
Unrecognized tax benefit relating to continuing operations at end of period	$ 4,000	$ 5,900

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 2006 through 2013 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

At June 30, 2014, and December 31, 2013, accounts payable included the remaining unpaid balance of equity tax liability of $1.7 million (December 31, 2013 - $3.3 million), a Colombian tax of 6% on a legislated measure calculated based on the Company's Colombian segment's balance sheet equity for tax purposes at January 1, 2011. The tax is payable in eight semi-annual installments over four years, but was expensed in the first quarter of 2011 at the commencement of the four-year period.

9. Contingencies

Gran Tierra Energy Colombia, Ltd. and Petrolifera Petroleum (Colombia) Ltd (collectively "GTEC") and Ecopetrol, the contracting parties of the Guayuyaco Association Contract, are engaged in a dispute regarding the interpretation of the procedure for allocation of oil produced and sold during the long-term test of the Guayuyaco-1 and Guayuyaco-2 wells, prior to GTEC's purchase of the companies originally involved in the dispute. There has been no agreement between the parties, and Ecopetrol filed a lawsuit in the Contravention Administrative Tribunal in the District of Cauca (the "Tribunal") regarding this matter. During the first quarter of 2013, the Tribunal ruled in favor of Ecopetrol and awarded Ecopetrol 44,025 bbl of oil. GTEC has filed an appeal of the ruling to the Supreme Administrative Court (Consejo de Estado) in a second instance procedure. During the three months ended March 31, 2013, based on market oil prices in Colombia, Gran Tierra accrued $4.4 million in the interim unaudited condensed consolidated financial statements in relation to this dispute (Note 10).

Gran Tierra's production from the Costayaco Exploitation Area is subject to an additional royalty (the "HPR royalty"), which applies when cumulative gross production from an Exploitation Area is greater than five MMbbl. The HPR royalty is calculated on the difference between a trigger price defined in the Chaza Block exploration and production contract (the "Chaza Contract") and the sales price. The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") has interpreted the Chaza Contract as requiring that the HPR royalty must be paid with respect to all production from the Moqueta Exploitation Area and initiated a noncompliance procedure under the Chaza Contract, which was contested by Gran Tierra because the Moqueta Exploitation Area and the Costayaco Exploitation Area are separate Exploitation Areas. ANH did not proceed with that noncompliance procedure. Gran Tierra also believes that the evidence shows that the Costayaco and Moqueta fields are two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra’s view that, pursuant to the terms of the Chaza Contract, the HPR royalty is only to be paid with respect to production from the Moqueta Exploitation Area when the accumulated oil production from that Exploitation Area exceeds five MMbbl. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process under the Chaza Contract and filed an arbitration claim seeking a decision that the HPR royalty is not payable until production from the Moqueta Exploitation Area exceeds five MMbbl. The ANH filed a response to the claim seeking a declaration that its interpretation is correct and a counterclaim seeking, amongst other remedies, declarations that Gran Tierra breached the Chaza Contract by not paying the disputed HPR royalty, that the amount of the alleged HPR royalty that is payable, and that the Chaza Contract be terminated. Gran Tierra filed a response to the ANH's counterclaim and filed its comments on the ANH's responses to Gran Tierra's claim. The ANH filed an amended counterclaim and Gran Tierra filed a response to the ANH's amended counterclaim. As at June 30, 2014, total cumulative production from the Moqueta Exploitation Area was 3.2 MMbbl. The estimated compensation which would be payable on cumulative production to that date if the ANH is successful in the arbitration is $52.9 million. At this time no amount has been accrued in the interim unaudited condensed consolidated financial statements nor deducted from the Company's reserves for the disputed HPR royalty as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Based on the Company's understanding of the ANH's position, the estimated compensation which would be payable if the ANH’s interpretation is correct could be up to $35.6 million as at June 30, 2014. 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.

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

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

Letters of credit

At June 30, 2014, the Company had provided promissory notes totaling $67.7 million (December 31, 2013 - $52.5 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements.

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

Financial Instruments

At June 30, 2014, the Company’s financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, trading securities, accounts payable, accrued liabilities, foreign currency derivatives included in current assets and contingent consideration and contingent liability included in other long-term liabilities.

Fair Value Measurement

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

The fair value of the trading securities which were received as consideration on the sale of the Company's Argentina business unit (Note 3) was estimated based on quoted market prices in an active market.

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

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

The fair value of the contingent liability which relates to a dispute with Ecopetrol (Note 9) was estimated based on the fair value of the amount awarded using market oil prices in Colombia.

The fair value of the trading securities, foreign currency derivatives, contingent consideration and the contingent liability related to the Ecopetrol dispute at June 30, 2014, and December 31, 2013, were as follows:

(Thousands of U.S. Dollars)	As at June 30, 2014	December 31, 2013
Trading securities (Note 3)	$14,251	$—
Foreign currency derivatives	12	—
Contingent consideration	1,061	1,061
Contingent liability (Note 9)	4,400	4,400

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

(Thousands of U.S. Dollars)	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Trading securities gain	$339	$—	$339	$—
Foreign currency derivatives gain	2,265	—	4,674	—
	$2,604	$—	$5,013	$—

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

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

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

At June 30, 2014, the fair value of the trading securities acquired in connection with the disposal of the Argentina business unit (Note 3) was determined using Level 1 inputs. At June 30, 2014, the fair value of the foreign currency derivatives was determined using Level 2 inputs. At June 30, 2014, and December 31, 2013, the fair value of the contingent consideration payable in connection with the Brazil acquisition was determined using Level 3 inputs and the fair value of the contingent liability which relates to a dispute with Ecopetrol (Note 9) was determined using Level 1 inputs. The disclosure in the paragraph below regarding the fair value of cash and restricted cash is based on Level 1 inputs.

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

Credit Risk

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

At June 30, 2014, cash and cash equivalents and restricted cash included balances in savings and checking accounts, as well as term deposits and certificates of deposit, placed primarily with financial institutions with strong investment grade ratings or governments, or the equivalent in the Company's operating areas.

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

At June 30, 2014, the Company had the following open foreign currency derivative position:
Forward contracts

Currency	Contract Type	Notional (Millions of Colombian Pesos)	Weighted Average Fixed Rate Received (Colombian Pesos - U.S. Dollars)	Expiration
Colombian pesos	Buy	712.2	1,976	February 2015

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 six months ended June 30, 2014, the Company had two customers that were significant to the Colombian segment and one customer that was significant to the Brazilian segment.

To reduce the concentration of exposure to any individual counterparty, the Company utilizes a group of investment-grade rated counterparties, primarily 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 foreign currency derivative instruments.

For the six months ended June 30, 2014, 95% (six months ended June 30, 2013 - 96%) of the Company's revenue and other income from continuing operations was generated in Colombia.

Foreign Exchange Risk

Unrealized foreign exchange gains and losses 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 $96,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

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.

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

This report, and in particular this Management’s Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language at the very beginning of this Quarterly Report on Form 10-Q regarding the identification of and risks relating to forward-looking statements, as well as Part II, Item 1A “Risk Factors” in this Quarterly Report on Form 10-Q.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements" as set out in Part I, Item 1 of this Quarterly Report on Form 10-Q as well as the "Financial Statements and Supplementary Data" and "Management’s Discussion and Analysis of Financial Condition and Results of Operations" included in Part II, Items 8 and 7, respectively, of our Annual Report on Form 10-K, filed with the U.S. Securities and Exchange Commission (“SEC”) on February 26, 2014.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America with business units in Colombia, Peru and Brazil, and we are headquartered in Calgary, Alberta, Canada. For the six months ended June 30, 2014, 95% (six months ended June 30, 2013 - 96%) of our revenue and other income from continuing operations was generated in Colombia.

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. The decision to sell our Argentina business unit followed recent significant exploration success in Peru, ongoing success in Colombia and ongoing evaluations in Brazil and was due to a decision to focus our human and capital resources in areas that we believe will provide the greatest return for our shareholders and drive growth in the future. In accordance with generally accepted accounting principles in the United States of America, 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 3, "Discontinued Operations," of our interim unaudited condensed consolidated financial statements for the three and six months ended June 30, 2014.

In this Management’s Discussion and Analysis of Financial Condition and Results of Operations, unless otherwise stated production represents production volumes NAR adjusted for inventory changes and losses.

Highlights

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
Production (BOEPD) (1)(2)	17,524	19,058	(8)	18,135	19,583	(7)
Prices Realized - per BOE (1)	$92.74	$86.64	7	$91.09	$94.94	(4)
Revenue and Other Income ($000s) (1)	$148,526	$150,574	(1)	$300,381	$337,161	(11)
Income from Continuing Operations ($000s) (1)	$31,484	$49,584	(37)	$81,256	$109,584	(26)
Loss from Discontinued Operations, Net of Income Taxes ($000s)	$(22,347)	$(1,801)	—	$(26,990)	$(3,888)	594
Net Income ($000s)	$9,137	$47,783	(81)	$54,266	$105,696	(49)
Income (loss) Per Share - Basic						
Income from Continuing Operations (1)	$0.11	$0.18	(39)	$0.29	$0.38	(24)
Loss from Discontinued Operations, Net of Income Taxes	(0.08)	(0.01)	700	(0.10)	(0.01)	900
Net income	$0.03	$0.17	(82)	$0.19	$0.37	(49)
Income (loss) Per Share - Diluted						
Income from Continuing Operations (1)	$0.11	$0.18	(39)	$0.28	$0.38	(26)
Loss from Discontinued Operations, Net of Income Taxes	(0.08)	(0.01)	700	(0.09)	(0.01)	800
Net income	$0.03	$0.17	(82)	$0.19	$0.37	(49)
Funds Flow From Continuing Operations ($000s) (1)(3)	$85,145	$85,836	(1)	$171,814	$188,349	(9)
Capital Expenditures For Continuing Operations ($000s) (1)	$91,339	$88,553	3	$173,440	$162,757	7

	As at		
	June 30, 2014	December 31, 2013	% Change
Cash & Cash Equivalents ($000s)	$332,359	$428,800	(22)

Working Capital (including cash & cash equivalents) ($000s)	$328,044	$245,827	33	
Property, Plant & Equipment ($000s)	$1,248,676	$1,260,172	(1	)

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(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes, associated with discontinued operations was 2,426 BOEPD and 2,744 BOEPD for the three and six months ended June 30, 2014, and 3,073 BOEPD and 3,192 BOEPD for the corresponding periods in 2013. Argentina production for the three and six months ended June 30, 2014, was calculated to the date of sale of June 25, 2014.

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

(3) Funds flow from continuing operations is a non-GAAP measure which does not have any standardized meaning prescribed under generally accepted accounting principles in the United States of America ("GAAP"). Management uses this financial measure to analyze operating performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income, and believes that this financial measure is also useful supplemental information for investors to analyze operating performance and our financial results. Investors should be cautioned that this measure should not be construed as an alternative to net income or other measures of financial performance as determined in accordance with GAAP. Our method of calculating this measure may differ from other companies and, accordingly, it may not be comparable to similar measures used by other companies. Funds flow from continuing operations, as presented, is net income adjusted for loss from discontinued operations, net of income taxes, depletion, depreciation, accretion and impairment ("DD&A") expenses, deferred tax expense or recovery, non-cash stock-based compensation, unrealized foreign exchange gain or loss, unrealized financial instruments gain or loss, equity tax and other loss. A reconciliation from net income to funds flow from continuing operations is as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
Funds Flow From Continuing Operations - Non-GAAP Measure ($000s)	2014	2013	2014	2013
Net income	$9,137	$47,783	$54,266	$105,696
Adjustments to reconcile net income to funds flow from continuing operations				
Loss from discontinued operations, net of income taxes	22,347	1,801	26,990	3,888
DD&A expenses	41,937	55,592	86,201	106,054
Deferred tax expense (recovery)	1,419	(8,213)	(841)	(15,715)
Non-cash stock-based compensation	1,144	2,213	2,624	4,110
Unrealized foreign exchange loss (gain)	8,745	(11,622)	4,567	(18,366)
Unrealized financial instruments loss (gain)	2,058	—	(351)	—
Equity tax	(1,642)	(1,718)	(1,642)	(1,718)
Other loss	—	—	—	4,400
Funds flow from continuing operations	$85,145	$85,836	$171,814	$188,349

- For the three and six months ended June 30, 2014, oil and gas production NAR before inventory adjustments and losses increased to 19,857 and 19,445 BOEPD compared with 19,373 and 19,004 BOEPD in the corresponding periods in 2013, respectively. In 2014, production from new wells in the Moqueta field in the Chaza Block and new wells in the Llanos-22 Block and fewer days of pipeline disruptions had a positive effect on production NAR before inventory adjustments and losses in Colombia.

- For the three and six months ended June 30, 2014, oil and gas production, NAR and adjusted for inventory changes and losses, decreased by 8% to 17,524 BOEPD and by 7% to 18,135 BOEPD compared with the corresponding periods in 2013, respectively, due to inventory changes. During the three and six months ended June 30, 2014, a net inventory increase accounted for 0.2 MMbbl or 2,333 bopd and 0.2 MMbbl or 1,310 bopd of reduced production compared with a net inventory reduction in the six months ended June 30, 2013, which accounted for 0.1 MMbbl or 578 bopd of increased production. In the three and six months ended June 30, 2014, production was 82% from the

Chaza Block in Colombia.

- For the three and six months ended June 30, 2014, revenue and other income decreased by 1% to $148.5 million and by 11% to $300.4 million compared with $150.6 million and $337.2 million in the corresponding periods in 2013, respectively. The decrease was primarily due to higher inventory and the effect of changes in realized prices. The average price realized per BOE increased by 7% to $92.74 and decreased by 4% to $91.09 for the three and six months ended June 30, 2014, from $86.64 and $94.94, in the comparable periods in 2013, respectively.

- Income from continuing operations was $31.5 million, or $0.11 per share basic and diluted, and $81.3 million, or $0.29 per share basic and $0.28 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with $49.6 million, or $0.18 per share basic and diluted, and $109.6 million, or $0.38 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three months ended June 30, 2014, decreased oil and natural gas sales as a result of higher inventory, and higher operating, general and administrative ("G&A") and income tax expenses and foreign exchange losses, were only partially offset by decreased DD&A expenses and financial instruments gains. For the six months ended June 30, 2014, decreased oil and natural gas sales, increased G&A expenses and foreign exchange losses were only partially offset by lower operating, DD&A and income tax expenses, financial instruments gains and the absence of other loss.

- Loss from discontinued operations, net of income taxes, was $22.3 million, or $0.08 per share basic and diluted, and $27.0 million, or $0.10 per share basic and $0.09 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with loss of $1.8 million, or $0.01 per share basic and diluted, and $3.9 million, or $0.01 per share basic and diluted, in the corresponding periods in 2013, respectively. Loss from discontinued operations, net of income taxes, increased compared with the corresponding period in 2013 due to the recognition of a loss on sale of the Argentina business unit of $19.3 million in the three and six months ended June 30, 2014.

- Net income was $9.1 million, or $0.03 per share basic and diluted, and $54.3 million, or $0.19 per share basic and diluted, for the three and six months ended June 30, 2014, respectively, compared with $47.8 million, or $0.17 per share basic and diluted, and $105.7 million, or $0.37 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three and six months ended June 30, 2014, the decrease was due to lower income from continuing operations and the recognition of a loss on sale of the Argentina business unit.

- For the three and six months ended June 30, 2014, funds flow from continuing operations decreased by 1% to $85.1 million and by 9% to $171.8 million, respectively. For the three months ended June 30, 2014, decreased oil and natural gas sales, and higher operating, G&A and income tax expenses and realized foreign exchange losses, were only partially offset by realized financial instruments gains. For the six months ended June 30, 2014, decreased oil and natural gas sales, increased G&A expenses and realized foreign exchange losses were only partially offset by lower operating and income tax expenses and realized financial instruments gains.

- Cash and cash equivalents were $332.4 million at June 30, 2014, compared with $428.8 million at December 31, 2013. The decrease in cash and cash equivalents during the six months ended June 30, 2014, was primarily the result of cash capital expenditures of $158.2 million, cash used in investing activities of discontinued operations of $12.4 million and a $143.1 million change in assets and liabilities from operating activities, partially offset by funds flow from continuing operations of $171.8 million, net proceeds from sale of Argentina business unit of $42.8 million, cash used in operating activities of discontinued operations of $4.8 million and proceeds from the issuance of shares of common stock of $7.1 million.

- Working capital (including cash and cash equivalents) was $328.0 million at June 30, 2014, an $82.2 million increase from December 31, 2013.

- Property, plant and equipment ("PPE") at June 30, 2014, was $1.2 billion, a decrease of $11.5 million from December 31, 2013, as a result of the sale of the Argentina business unit PPE of $100.2 million, $90.5 million of depletion, depreciation and impairment expenses related to continuing operations, $12.9 million of depletion, depreciation and impairment expenses recorded in loss from discontinued operations, partially offset by $173.4 million of capital expenditures related to continuing operations and $18.7 million of capital expenditures related to discontinued operations.

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Capital expenditures for continuing operations for the six months ended June 30, 2014, were $173.4 million compared with $162.8 million for the six months ended June 30, 2013. In 2014, these capital expenditures included drilling of $116.6 million, geological and geophysical ("G&G") expenditures of $26.8 million, facilities of $14.2 million and other expenditures of $15.8 million.

Business Environment Outlook

Our revenues are significantly affected by pipeline and other oil transportation disruptions in Colombia and the continuing fluctuations in oil prices. Oil prices are volatile and unpredictable and are influenced by concerns about financial markets and the impact of the worldwide economy on oil supply and demand.

We believe our current operations and 2014 capital expenditure program can be funded from cash flow from existing operations and cash on hand. Should our operating cash flow decline due to unforeseen events, including additional pipeline delivery restrictions and other oil transportation disruptions in Colombia or a downturn in oil and gas prices, we would examine measures such as capital expenditure program reductions, use of our revolving credit facility, issuance of debt, disposition of assets, or issuance of equity. Continuing global social and political uncertainty, economic uncertainty in the Middle East, United States, Europe and Asia and changes in global supply and infrastructure are having an impact on world markets, and 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.

We have noted recently that in the Department of Putumayo in Colombia where we operate, additional efforts are being made by new ethnic groups to utilize the courts to require that they be consulted, and obtain benefits, despite a company's prior compliance with the legislated consultation process and the receipt of the necessary permits to drill and operate. See "Risk Factors: Our Business is Subject to Local Legal, Political and Economic Factors Which Are Beyond Our Control, Which Could Impair Our Ability to Expand Our Operations or Operate Profitably."

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

Consolidated Results of Operations

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales (1)	$147,888	$150,250	(2)	$298,993	$336,490	(11)
Interest income (1)	638	324	97	1,388	671	107
	148,526	150,574	(1)	300,381	337,161	(11)
Operating expenses (1)	25,346	23,970	6	47,212	56,013	(16)
DD&A expenses (1)	41,937	55,592	(25)	86,201	106,054	(19)
G&A expenses (1)	13,932	9,090	53	26,795	18,112	48
Foreign exchange loss (gain) (1)	10,044	(12,622)	180	5,834	(18,979)	(131)
Financial instruments gain (1)	(2,604)	—	—	(5,013)	—	—
Other loss (1)	—	—	—	—	4,400	(100)
	88,655	76,030	17	161,029	165,600	(3)
Income from continuing operations before income taxes (1)	59,871	74,544	(20)	139,352	171,561	(19)
Income tax expense (1)	(28,387)	(24,960)	14	(58,096)	(61,977)	(6)
Income from continuing operations (1)	$31,484	$49,584	(37)	$81,256	$109,584	(26)
Loss from discontinued operations, net of income taxes	(22,347)	(1,801)	—	(26,990)	(3,888)	594
Net income	$9,137	$47,783	(81)	$54,266	$105,696	(49)
Production (1)(2)						
Oil and NGL's, bbl	1,573,071	1,732,514	(9)	3,250,049	3,542,674	(8)
Natural gas, Mcf	129,711	10,468	—	194,490	10,468	—
Total production, BOE	1,594,690	1,734,259	(8)	3,282,464	3,544,419	(7)
Average Prices (1)						
Oil and NGL's per bbl	$93.72	$86.71	8	$91.74	$94.99	(3)
Natural gas per Mcf	$4.01	$7.18	(44)	$4.79	$7.18	(33)
Consolidated Results of Operations per BOE						
Oil and natural gas sales (1)	$92.74	$86.64	7	$91.09	$94.94	(4)
Interest income (1)	0.40	0.19	111	0.42	0.19	121
	93.14	86.83	7	91.51	95.13	(4)
Operating expenses (1)	15.89	13.82	15	14.38	15.80	(9)
DD&A expenses (1)	26.30	32.06	(18)	26.26	29.92	(12)
G&A expenses (1)	8.74	5.24	67	8.16	5.11	60
Foreign exchange loss (gain) (1)	6.30	(7.28)	187	1.78	(5.35)	(133)
Financial instruments gain (1)	(1.63)	—	—	(1.53)	—	—

Other loss (1)	—	—	—	—	1.24	(100)
	55.60	43.84	27	49.05	46.72	5
Income from continuing operations before income taxes (1)	37.54	42.99	(13)	42.46	48.41	(12)
Income tax expense (1)	(17.80)	(14.39)	24	(17.70)	(17.49)	1
Income from continuing operations (1)	$19.74	$28.60	(31)	$24.76	$30.92	(20)

(1) Excludes amounts relating to discontinued operations. Oil and gas production, NAR and adjusted for inventory changes, associated with discontinued operations was 2,426 BOEPD and 2,744 BOEPD for the three and six months ended June 30,

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2014, and 3,073 BOEPD and 3,192 BOEPD for the corresponding periods in 2013. Argentina production for the three and six months ended June 30, 2014, was calculated to the date of sale of June 25, 2014.

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

Net income for the three and six months ended June 30, 2014, was $9.1 million and $54.3 million, respectively, compared with $47.8 million and $105.7 million in the comparable periods in 2013. On a per share basis, net income decreased to $0.03 per share basic and diluted for the three months ended June 30, 2014, from $0.17 per share basic and diluted in the corresponding period in 2013. For the six months ended June 30, 2014, net income decreased to $0.19 per share basic and diluted from $0.37 per share basic and diluted in the corresponding period in 2013. For the three and six months ended June 30, 2014, the decrease was due to lower income from continuing operations and higher loss from discontinued operations, net of income taxes.

Income from continuing operations was $31.5 million, or $0.11 per share basic and diluted, and $81.3 million, or $0.29 per share basic and $0.28 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with $49.6 million and $109.6 million, or $0.18 per share basic and diluted, and $0.38 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three months ended June 30, 2014, decreased oil and natural gas sales, and higher operating, G&A and income tax expenses and foreign exchange losses, were only partially offset by decreased DD&A expenses and financial instruments gains. For the six months ended June 30, 2014, decreased oil and natural gas sales, increased G&A expenses and foreign exchange losses were only partially offset by lower operating, DD&A and income tax expenses, financial instruments gains and the absence of other loss.

Loss from discontinued operations, net of income taxes, was $22.3 million, or $0.08 per share basic and diluted, and $27.0 million, or $0.10 per share basic and $0.09 per share diluted, for the three and six months ended June 30, 2014, respectively, compared with $1.8 million and $3.9 million, respectively, or $0.01 per share basic and diluted, in the corresponding periods in 2013, respectively. For the three and six months ended June 30, 2014, loss from discontinued operations, net of tax, included loss on disposal of the Argentina business unit of $19.3 million.

Oil and NGL production NAR before inventory adjustments and losses for the three and six months ended June 30, 2014, increased to 19,619 and 19,266 bopd compared with 19,356 and 18,995 bopd in the corresponding periods in 2013, respectively. In 2014, production from new wells in the Moqueta field in the Chaza Block and new wells in the Llanos-22 Block and fewer days of pipeline disruptions had a positive effect on production NAR before inventory adjustments and losses in Colombia.

Oil and NGL production NAR after inventory adjustments and losses for the three and six months ended June 30, 2014, decreased by 9% to 17,286 bopd and by 8% to 17,956 bopd compared with the corresponding periods in 2013, respectively. The decrease in production was primarily due to an increase in oil inventory in the Ecopetrol S.A. ("Ecopetrol") operated Trans-Andean oil pipeline (the "OTA pipeline”) and associated Ecopetrol owned facilities and in our crude oil storage tanks in the Putumayo Basin as a result of pipeline disruptions, and deliveries to a customer with a protracted sales cycle whereby the transfer of ownership will not occur until oil is exported. During the six months ended June 30, 2014, a net inventory increase accounted for 0.2 MMbbl or 1,310 bopd of reduced production compared with a net inventory reduction in 2013 which accounted for 0.1 MMbbl or 578 bopd increased production. The oil inventory reduction in 2013 was due to a decrease in oil inventory in the OTA pipeline and associated Ecopetrol owned facilities in the Putumayo Basin and reduced oil inventory related to sales to a customer in Colombia with a protracted sales cycle whereby the transfer of ownership occurred upon export. In the three and six months ended June 30, 2014 and 2013, the impact of OTA pipeline disruptions on production was partially mitigated by selling a portion of our oil through trucking and an alternative pipeline.

Average realized oil prices increased by 8% to $93.72 per bbl for the three months ended June 30, 2014, from $86.71 per bbl in the comparable period in 2013 and decreased by 3% to $91.74 per bbl for the six months ended June 30, 2014, from $94.99 per bbl in the comparable period in 2013. Average Brent oil prices for the three and six months ended June 30, 2014, were $109.70 and $108.93 per bbl, respectively, compared with $102.58 and $107.54 per bbl in the corresponding periods in 2013. Average WTI oil prices for the three and six months ended June 30, 2014, were $102.99 and $100.84 per bbl, respectively, compared with $94.22 and $94.31 per bbl in the corresponding periods in 2013. During the three and six months ended June 30, 2014, 39% and 43% of our oil and gas volumes sold in Colombia, respectively, were to a customer which takes delivery at the Costayaco battery and transports the oil by truck over a 1,500 km route to the Port of Barranquilla. The sales price for this customer is based on average WTI prices plus a Vasconia differential and premium, less trucking costs. For sales to this customer, the trucking costs are recorded as a reduction of the realized price and not as operating costs. Sales to this customer during the corresponding periods in 2013 were 51% and 40% of our oil and gas volumes sold in Colombia

Revenue and other income for the three months ended June 30, 2014, decreased to $148.5 million from $150.6 million in the comparable period in 2013 as a result of decreased production primarily due to increased oil inventory, partially offset by increased realized prices. Revenue and other income for the six months ended June 30, 2014, decreased to $300.4 million from $337.2 million in the comparable period in 2013. due to higher inventory levels as well as lower realized prices.

Operating expenses increased by 6% to $25.3 million and decreased by 16% to $47.2 million for the three and six months ended June 30, 2014, respectively, from the comparable periods in 2013. For the three months ended June 30, 2014, the increase in operating expenses was primarily due to an increase in the operating cost per BOE, partially offset by decreased production. For the six months ended June 30, 2014, the decrease in operating expenses was due to a decrease in the operating cost per BOE combined with decreased production.

On a per BOE basis, operating expenses increased by 15% to $15.89 and decreased by 9% to $14.38 for the three and six months ended June 30, 2014, respectively, from $13.82 and $15.80 in the comparable periods in 2013. Operating expenses per BOE increased in the three months ended June 30, 2014, due to an increase in transportation costs as a result of lower volumes subject to alternative transportation arrangements, for which trucking costs related to a 1,500 km route are paid by the purchaser and netted to arrive at our realized price rather than recorded as transportation expenses. The decrease in operating costs per BOE in the six months ended June 30, 2014, was due to inventory volumes liquidated in the comparative period in 2013 which had high transportation costs due to the delivery point to which they were sold and to which we did not deliver in the current period. Operating expenses per BOE also decreased in the six months ended June 30, 2014 as a result of deferred workover expenses, lower fuel consumption and lower training costs.

DD&A expenses for the three months ended June 30, 2014, decreased to $41.9 million from $55.6 million in the comparable period in 2013, due to lower production and a decreased depletion rate. On a per BOE basis, the depletion rate decreased by 18% to $26.30 from $32.06. DD&A expenses for the three months ended June 30, 2013, included a $2.0 million ceiling test impairment loss in our Brazil cost center. On a per BOE basis, in addition to the 2013 impairment charge, the decrease was due to an increase in reserves and a decrease in costs in the depletable base relating to lower future development costs and the receipt of a termination payment in Brazil in the third quarter of 2013 which reduced the cost base. DD&A expenses for the six months ended June 30, 2014, decreased to $86.2 million ($26.26 per BOE) from $106.1 million ($29.92 per BOE) in the comparable period in 2013, due to lower production and a decreased depletion rate.

G&A expenses for the three months ended June 30, 2014, increased by 53% to $13.9 million ($8.74 per BOE) from $9.1 million ($5.24 per BOE) compared with the corresponding period in 2013. Increased employee related costs, higher consulting expenses associated with increased activity, expanded operations in Peru and higher bank fees, were only partially offset by higher G&A allocations to capital projects within the business units. During the three months ended June 30, 2013, we received $1.0 million from the U.S. Federal Government for assets recovered from our former U.S. securities counsel as compensation for damages suffered in 2006. This amount was recorded as a reduction of G&A expenses in the corresponding period in 2013.

G&A expenses for the six months ended June 30, 2014, increased by 48% to $26.8 million ($8.16 per BOE) from $18.1 million ($5.11 per BOE), the corresponding period in 2013. The increase was primarily due to increased employee related costs, higher consulting expenses associated with increased activity, expanded operations in Peru and higher stock-based compensation expense associated with restricted stock units ("RSUs") and stock options. These increases were partially offset by higher G&A allocations to capital projects within the business units.

For the three and six months ended June 30, 2014, the foreign exchange loss was $10.0 million and $5.8 million, respectively. For the three months ended June 30, 2014, we had realized foreign exchange losses of $1.3 million and an unrealized non-cash foreign exchange loss of $8.7 million. For the six months ended June 30, 2014, we had realized foreign exchange losses of $1.2 million and an unrealized non-cash foreign exchange loss of $4.6 million. Foreign exchange losses and gains are primarily a result of a net monetary liability position in Colombia and the strengthening of Colombian Peso versus U.S. dollar..

For the three months ended June 30, 2013, there was a foreign exchange gain of $12.6 million, comprising an $11.6 million unrealized non-cash foreign exchange gain and realized foreign exchange gains of $1.0 million. For the six months ended June 30, 2013, there was a foreign exchange gain of $19.0 million, comprising an $18.4 million unrealized non-cash foreign exchange gain and realized foreign exchange gains of $0.6 million. The unrealized non-cash foreign exchange gain was a result of a net monetary liability position in Colombia and the weakening of Colombian Peso versus U.S, dollar.

Financial instruments gain of $2.6 million and $5.0 million in the three and six months ended June 30, 2014, respectively, included a realized financial instrument gain of $4.7 million. For the three months ended June 30, 2014, the realized financial instrument gain was partially offset by unrealized financial instruments losses of $2.1 million. In the six months ended June 30, 2014, we had unrealized financial instruments gains of $351 thousand.

The gains and losses primarily related our Colombian peso non-deliverable forward contracts. We purchased these contracts for purposes of fixing the exchange rate at which we will purchase Colombian pesos to settle our income tax installment payments. Financial instruments gain in the three and six months ended June 30, 2014, also included a $0.3 million unrealized gain on the Madalena shares. We received these shares in connection with the sale of our Argentina business unit. Madalena is an independent, Canadian-based, domestic and international upstream oil and gas company whose main business activities include exploration, development and production of crude oil, natural gas liquids and natural gas. Madalena's shares are listed on the Canadian TSX Venture Exchange.

Other loss of $4.4 million in the six months ended June 30, 2013, related to a contingent loss accrued in connection with a legal dispute in which we received an adverse legal judgment in the first quarter of 2013. We have filed an appeal against the judgment.

Income tax expense related to continuing operations was $28.4 million and $58.1 million for the three and six months ended June 30, 2014, respectively, compared with $25.0 million and $62.0 million in the comparable periods in 2013. The decrease for the six months ended June 30, 2014, was primarily due to lower taxable income in Colombia. The effective tax rate was 42% in the six months ended June 30, 2014, compared with 36% in the comparable period in 2013. The change in the effective tax rate was primarily due to an increase in non-deductible foreign currency translation adjustments and other permanent differences, partially offset by a decrease in the valuation allowance.

For the six months ended June 30, 2014, the differential between the effective tax rate of 42% and the 35% U.S. statutory rate was primarily attributable to a non-deductible third party royalty in Colombia, the impact of other local taxes, non-deductible stock-based compensation, and other permanent differences which were partially offset by the deductible foreign tax rate differential. The variance from the 35% U.S. statutory rate for 2013 was primarily attributable to a non-deductible third party royalty in Colombia, an increase in valuation allowance and non-deductible stock-based compensation, which was partially offset by a decrease in non-deductible foreign currency translation adjustments, the foreign tax rate differential and other permanent adjustments.

2014 Work Program and Capital Expenditure Program

Our 2014 capital program has been revised to $482 million from $495 million. This includes: $249 million for Colombia; $173 million for Peru; $37 million for Brazil; $18 million for Argentina; and $5 million associated with corporate activities. The decrease in our capital spending is primarily due to the sale of the Argentina business unit. The capital spending program allocates $278 million for drilling; $77 million for facilities, pipelines and other; $122 million for G&G expenditures; and $5 million for corporate activities. Of the $278 million allocated to drilling, approximately 20% is for exploration and the balance is for appraisal and development drilling.

Our 2014 work program is intended to create both growth and value by developing existing assets to increase reserves and
production levels, the construction of pipelines and facilities in the areas with proved reserves, and maturing our exploration prospects through seismic acquisition and drilling. We expect to finance our 2014 capital program through cash flows from operations and cash on hand, while retaining financial flexibility to undertake further development opportunities and pursue acquisitions. However, as a result of the nature of the oil and natural gas exploration, development and exploitation industry, budgets are regularly reviewed with respect to both the success of expenditures and other opportunities that become available. Accordingly, while we currently intend that funds be expended as set forth in our 2014 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

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Segmented Results from Continuing Operations – Colombia

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	% Change	2014	2013	% Change
(Thousands of U.S. Dollars)						
Oil and natural gas sales	$139,350	$144,333	(3)	$284,285	$324,336	(12)
Interest income	184	143	29	321	304	6
	139,534	144,476	(3)	284,606	324,640	(12)
Operating expenses	23,281	22,349	4	43,486	52,301	(17)
DD&A expenses	39,348	48,364	(19)	80,598	94,320	(15)
G&A expenses	5,798	3,379	72	10,181	8,015	27
Foreign exchange loss (gain)	10,891	(14,086)	177	6,523	(20,534)	(132)
Financial instruments gain	(2,265)	—	—	(4,674)	—	—
Other loss	—	—	—	—	4,400	(100)
	77,053	60,006	28	136,114	138,502	(2)
Income from continuing operations before income taxes	$62,481	$84,470	(26)	$148,492	$186,138	(20)
Production (1)						
Oil and NGL's, bbl	1,483,854	1,665,555	(11)	3,094,509	3,411,881	(9)
Natural gas, Mcf	129,711	10,468	—	194,490	10,468	—
Total production, BOE	1,505,473	1,667,300	(10)	3,126,924	3,413,626	(8)
Average Prices						
Oil and NGL's per bbl	$93.56	$86.61	8	$91.57	$95.04	(4)
Natural gas per Mcf	$4.01	$7.18	(44)	$4.79	$7.18	(33)
Segmented Results of Operations per BOE						