2012 FINANCIALS

GranTierra
energy inc.

Preliminary Note to This Annual Report

The following information provided in this Annual Report has been taken from our Annual Report on Form 10-K, filed with the Securities and Exchange Commission on February 26, 2013, and has not been updated for events, including changes to our 2013 capital program, that have occurred subsequent to that date.

Statement Regarding Forward-Looking Statements

This Annual Report, particularly in the section entitled "Business" and the section entitled "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 Annual Report, 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 variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in the section entitled "Risk Factors" in this Annual Report. The information included herein is given as of the February 26, 2013, filing date of the Form 10-K with the Securities and Exchange Commission ("SEC"), except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Annual Report to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

Glossary of Oil and Gas Terms

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

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

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.

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. Production volumes are also reported net of inventory adjustments. 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.

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

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

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

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

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

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

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

- *Reserves*. Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.
- *Proved oil and gas reserves*. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

i. The area of the reservoir considered as proved includes:
   A. The area identified by drilling and limited by fluid contacts, if any, and
   B. Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
ii. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
iii. Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.
iv. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:
   A. Successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and
   B. The project has been approved for development by all necessary parties and entities, including governmental entities.
v. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

- *Probable reserves*. Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.
   i. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.
   ii. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.
   iii. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.
   iv. See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of section 210.4-10(a) of Regulations S-X.
- *Possible reserves*. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.
   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.

Business

General

Gran Tierra Energy Inc. together with its subsidiaries ("Gran Tierra", "us", "our", or "we") is an independent international energy company engaged in oil and gas acquisition, exploration, development and production. We own oil and gas properties in Colombia, Argentina, Peru and Brazil.

Our principal executive offices are located at 300, 625-11th Avenue S.W., Calgary, Alberta, Canada. The telephone number at our principal executive office is (403) 265-3221. All dollar ($) amounts referred to in this Annual Report are United States (U.S.) dollars, unless otherwise indicated.

Development of Our Business

Our company was incorporated under the laws of the State of Nevada on June 6, 2003, originally under the name Goldstrike Inc. We made our initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005. Since then, we have acquired oil and gas producing and non-producing assets in Colombia, Peru, Argentina and Brazil, with our largest acquisitions being the acquisition of Solana Resources Limited ("Solana") in 2008 and Petrolifera Petroleum Limited ("Petrolifera") in 2011.

In 2012:

- in Colombia, we added two blocks through the 2012 Colombia Bid Round and continued to focus on developing our producing fields, including Costayaco and Moqueta, and on the generation of exploration prospects;
- in Brazil, we acquired the remaining 30% working interest in our Recôncavo Basin Blocks, received declaration of commerciality for the Tiê field and received regulatory approval for the farm-out of Block BM-CAL-7 in the offshore Camamu Basin;
- in Peru, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block and operatorship to us and we entered into an agreement to acquire the remaining 40% working interest in this block; we commenced drilling an exploration well on Block 95; and, in Blocks 123 and 129, increased our working interest from 20% to 100%, subject to regulatory approval, and, subsequent to year end, assumed operatorship;
- in Argentina, we continued to focus on developing our producing fields, including the Surubi, Puesto Morales and Rinconada Norte fields.

In the year ended December 31, 2012, we incurred capital expenditures of $349.8 million (excluding changes in non-cash working capital and including the $36.6 million acquisition in Brazil and net of proceeds from disposition of oil and gas properties), including acquisitions of $49.1 million, drilling expenditures of $218.1 million, facilities expenses of $17.9 million, geological and geophysical ("G&G") expenses of $48.0 million and other expenditures of $16.7 million.

Our acreage as of December 31, 2012, including acquisitions and excluding farm-outs and relinquishments which were subject to various government approvals, included:

- 4.5 million gross acres in Colombia (3.7 million net) covering 23 exploration and production contracts, six of which were producing and 21 of which were operated by Gran Tierra (excludes four blocks or 277,072 gross and 210,692 net acres for which working interest changes were subject to approval);
- 1.3 million gross acres (0.6 million net) in Argentina covering 11 exploration and production contracts, eight of which were producing and nine of which were operated by Gran Tierra;
- 6.4 million gross acres (6.4 million net) in Peru covering five exploration licenses, all of which were frontier exploration areas and three of which were operated by Gran Tierra (includes three blocks or 3.3 million net acres which were subject to government approval). Subsequent to year end, we assumed operatorship of the two remaining blocks in Peru; and
- 0.4 million gross acres (61 thousand net) in Brazil covering five exploration blocks, one of which was producing and four of which were operated by Gran Tierra.

Reserves

Please see Appendix A for reserves information presented in accordance with the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101").

The following table sets forth our reserves as of December 31, 2012. The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in the section entitled "Risk Factors". The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. Therefore the accuracy of the reserve estimate is dependent on the quality of the data, the accuracy of the assumptions based on the data, and the interpretations and judgment related to the data.

We have developed internal policies for estimating and evaluating reserves. The policies we have developed are applied company wide, and are comprehensive in nature. Gran Tierra's internal controls over reserve estimates include reconciliation and review controls, including an independent internal review of assumptions used in the estimation by our reserves committee, and 100% of our reserves are evaluated by an independent reservoir engineering firm, GLJ Petroleum Consultants Ltd., at least annually.

The primary internal technical person in charge of overseeing the preparation of our reserve estimates is the General Manager of Engineering and Development Planning. He has a Bachelor of Science degree in petroleum engineering and is a professional engineer and member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He is responsible for our engineering activities including reserves reporting, asset evaluation, reservoir management, and field development. He has over 30 years of industry experience in various domestic and international engineering and management roles.

The technical person responsible for overseeing the reserves evaluation is a Vice President, Corporate Evaluations of GLJ Petroleum Consultants Ltd. He has a Bachelor of Science degree in engineering physics and is a registered professional engineer in the Province of Alberta. He has over 20 years of industry experience in various domestic and international engineering and management roles.

By applying our policies we have developed SEC compliant reserve estimates and disclosures. Our policies are applied by all staff involved in generating and reporting reserve estimates including geological, engineering and finance personnel. Calculations and data are reviewed at multiple levels of the organization to ensure consistent and appropriate standards and procedures.

No estimates of reserves comparable to those included herein have been included in a report to any federal agency other than the SEC.

Reserve Category (Net After Royalty; SEC Compliant)	Liquids[1] (Mbbl)	Natural Gas (MMcf)
Proved		
Developed		
Colombia	24,677	8,551
Argentina	2,459	2,777
Brazil	347	—
Total proved developed reserves	27,483	11,328
Undeveloped		
Colombia	6,432	921
Argentina	3,335	527
Brazil	1,244	—
Total proved undeveloped reserves	11,011	1,448
Total proved reserves	38,494	12,776
Probable		
Developed		
Colombia	5,671	783
Argentina	716	298
Brazil	397	—
Total probable developed reserves	6,786	1,081
Undeveloped		
Colombia	5,242	2,517
Argentina	1,814	1,538
Brazil	942	—
Total probable undeveloped reserves	7,998	4,055
Total probable reserves	14,784	5,136
Possible		
Developed		
Colombia	4,739	1,902
Argentina	1,447	695
Brazil	686	—
Total possible developed reserves	6,872	2,597
Undeveloped		
Colombia	8,428	2,337
Argentina	4,772	46,733
Brazil	1,384	—
Total possible undeveloped reserves	14,584	49,070
Total possible reserves	21,456	51,667

(1) Liquids include oil and NGLs. We have NGL reserves in small amounts in Colombia and Argentina only. Brazil liquids reserves are 100% oil.

Proved Undeveloped Reserves

At December 31, 2012, we had total proved undeveloped reserves NAR of 11.2 MMBOE (December 31, 2011 – 8.2 MMBOE), including 6.6 MMBOE in Colombia (December 31, 2011 – 4.6 MMBOE), 3.4 MMBOE in Argentina (December 31, 2011 – 3.3 MMBOE) and 1.2 MMBOE in Brazil (December 31, 2011 – 0.3 MMBOE). Approximately 27% of proved undeveloped reserves are located in our Puesto Morales field in Argentina. This field was acquired as a result of the Petrolifera acquisition in 2011. Additionally, approximately 22% and 28% of proved undeveloped reserves are in our Moqueta and Costayaco fields in Colombia. None of our proved undeveloped reserves at December 31, 2012, have remained undeveloped for five years or more since initial disclosure as proved reserves and we have adopted a development plan which indicates that the proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure as proved reserves.

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

	Oil Equivalent (MMBOE)
Balance, December 31, 2011	8.2
Purchases	0.1
Discoveries and extensions	3.9
Converted to proved producing	(3.6)
Technical revisions	2.6
Balance, December 31, 2012	11.2

In 2012, we converted 3.6 MMBOE, or 44% of the total year-end 2011 proved undeveloped reserves, to developed status. In 2012, we made investments, consisting solely of capital expenditures, of $44.0 million in Colombia and $19.5 million in Argentina associated with the development of proved undeveloped reserves. Approximately 94% of proved undeveloped reserves conversions occurred in the Costayaco and Moqueta fields in Colombia and 3% in the Puesto Morales field in Argentina. The majority of proved undeveloped conversions occurred as a result of ongoing development activities in the Costayaco and Moqueta fields in Colombia, including infill drilling and a pressure maintenance project in the Costayaco field and infill drilling and facilities development in the Moqueta field. The waterflood optimization program for the Sierra Blancas reservoir and the commencement of a horizontal well development program for the Loma Montosa reservoir, both in the Puesto Morales field in Argentina, also converted proved undeveloped reserves to proved developed reserves.

Sensitivity of Reserves to Prices by Principal Product Type and Price Scenario

The following table sets forth our reserves as at December 31, 2012, using different price cases involving changes to the Brent price. Firstly with a 10% increase and secondly with a 10% decrease. Natural gas prices are not affected by Brent, therefore the volumes of natural gas reserves do not change. Additionally, the oil price in Argentina is set by the government as described below under the caption "Marketing and Major Customers". Oil prices in Argentina are not sensitive to changes in Brent prices, therefore the price scenarios considered do not result in changes to oil and natural gas reserves for Argentina. Cost schedules were held constant for the two price cases.

	Proved Reserves		Probable Reserves		Possible Reserves	
Price Case	Liquids (Mbbl)[1]	Natural Gas (MMcf)	Liquids (Mbbl)	Natural Gas (MMcf)	Liquids (Mbbl)[1]	Natural Gas (MMcf)
Brent +10%						
Colombia	31,192	9,705	10,529	3,310	13,077	3,948
Argentina	5,794	3,304	2,530	1,836	6,219	47,427
Brazil	1,593	—	1,341	—	2,072	—
	38,579	13,009	14,400	5,146	21,368	51,375
Brent – 10%						
Colombia	30,964	9,443	11,178	3,347	13,621	4,255
Argentina	5,794	3,304	2,530	1,836	6,219	47,427
Brazil	1,586	—	1,334	—	2,063	—
	38,344	12,747	15,042	5,183	21,903	51,682

(1) Proved and possible liquid reserves are higher as a result of a 10% decrease in Brent as compared with a 10% increase in Brent. The lower price results in reduced additional government and third party royalties paid, increasing the NAR volumes.

Production Revenue and Price History

Certain information concerning oil and natural gas production, prices, revenues and operating expenses for the three years ended December 31, 2012, is set forth in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and in the Unaudited Supplementary Data provided following our Financial Statements. We prepared the estimate of standardized measure of proved reserves in accordance with the Financial Accounting Standards Board ("FASB") ASC 932, "Extractive Activities – Oil and Gas".

Drilling Activities

The following table summarizes the results of our exploration and development drilling activity for the past three years. Wells labeled as "In Progress" were in progress as of December 31, 2012.

	2012		2011		2010	
	Gross	**Net**	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	—	—	1.00	0.50	4.00	3.50
Dry	**3.00**	**2.50**	6.00	6.00	1.00	1.00
In Progress	**2.00**	**0.95**	1.00	0.44	3.00	2.43
Development						
Productive	**3.00**	**3.00**	8.00	7.20	2.00	1.70
Dry	—	—	1.00	1.00	—	—
In Progress	**2.00**	**2.00**	—	—	2.00	2.00
Total Colombia	**10.00**	**8.45**	17.00	15.14	12.00	10.63
Argentina						
Exploration						
Productive	**1.00**	**0.35**	2.00	0.70	—	—
Dry	**2.00**	**1.35**	1.00	1.00	—	—
In Progress	**3.00**	**1.70**	2.00	0.70	—	—
Development						
Productive	**10.00**	**9.20**	3.00	3.00	—	—
Dry	**1.00**	**1.00**	—	—	—	—
In Progress	**3.00**	**1.70**	2.00	2.00	1.00	0.93
Total Argentina	**20.00**	**15.30**	10.00	7.40	1.00	0.93
Brazil						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	**1.00**	**1.00**	2.00	1.40	—	—
Development						
Productive	**2.00**	**2.00**	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—		1.00	0.70	—	—
Total Brazil	**3.00**	**3.00**	3.00	2.10	—	—
Peru						
Exploration						
Productive	—	—	—	—	—	—
Dry	—	—	1.00	1.00	—	—
In Progress	**1.00**	**1.00**	—	—	—	—
Development						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
In Progress	—	—	—	—	—	—
Total Peru	**1.00**	**1.00**	1.00	1.00	—	—
Total	**34.00**	**27.75**	31.00	25.64	13.00	11.56

In 2012, we also undertook a pressure maintenance project in the Costayaco field in Colombia and the Puesto Morales Block in Argentina. We also undertook a waterflood optimization program for the Sierra Blancas reservoir in Argentina.

As at February 20, 2013, the results of wells in progress at December 31, 2012, are as follows:

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
Colombia	1.00	1.00	—	—	3.00	1.95
Argentina	2.00	1.35	—	—	4.00	2.05
Brazil	—	—	—	—	1.00	1.00
Peru	—	—	—	—	1.00	1.00
	3.00	2.35	—	—	9.00	6.00

Well Statistics

The following table sets forth our producing wells as of December 31, 2012:

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia (1)	29.0	20.5	1.0	0.4	30.0	20.9
Argentina (2)	85.0	70.1	11.0	11.0	96.0	81.1
Brazil	3.0	3.0	—	—	3.0	3.0
Peru	—	—	—	—	—	—
	117.0	93.6	12.0	11.4	129.0	105.0

(1) Includes 5.0 gross and net water injector wells and 20.0 gross and 15.9 net wells with multiple completions.

(2) Includes 15.0 gross and net water injector wells and 1.0 gross and net well with multiple completions.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2012:

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia	459,663	346,667	4,000,524	3,357,946	4,460,187	3,704,613
Argentina	706,640	296,905	561,388	301,401	1,268,028	598,306
Brazil	5,786	5,786	358,849	55,044	364,635	60,830
Peru	—	—	6,367,806	6,367,806	6,367,806	6,367,806
	1,172,089	649,358	11,288,567	10,082,197	12,460,656	10,731,555

(1) Excluded from undeveloped acreages are farm-out or assignment agreements for which government approval is pending. These pending approvals will result in a decrease of 210,692 net acres in Colombia and an increase of 3,302,752 net acres in Peru.

At December 31, 2012, our gross undeveloped acreage was located 56% in Peru (11% Block 95 and 31% Blocks 123 and 129), 36% in Colombia, 5% in Argentina and 3% in Brazil.

Business Strategy

Our plan is to continue to build an international oil and gas company through acquisition and exploitation of under-developed prospective oil and gas assets, and to develop these assets with exploration and development drilling to grow commercial reserves and production. Our initial focus is in select countries in South America, currently Colombia, Argentina, Peru, and Brazil; we will consider other regions for future growth should those regions make strategic and commercial sense in creating additional value.

We have applied a two-stage approach to growth, initially establishing a base of production, development and exploration assets by selective acquisitions, and secondly achieving additional reserve and production growth through drilling. We intend to duplicate this business model in other areas as opportunities arise. We pursue opportunities in countries with proven petroleum systems; attractive royalty, taxation and other fiscal terms; and stable legal systems.

A key to our business plan is positioning and being in the right place at the right time with the right resources. The fundamentals of this strategy are described in more detail below:

- Position in countries that are welcoming to foreign investment, that provide attractive fiscal terms, that have stable legal systems, that offer opportunities that we believe have been previously ignored or undervalued, and that have an active market with many available deals;
- Build a balanced portfolio of production, development and exploration assets and opportunities, with a drilling inventory that balances risks and rewards to create value;
- Retain operatorship of assets whenever possible to retain control of work programs, budgets, prospect generation, drilling operations and development activities; non-operating positions will be taken when operators bring strategic advantage to business growth;
- Engage qualified, experienced and motivated professionals;
- Establish an effective local presence, with strong constructive relationships with host governments, ministries, agencies and communities in which we operate;
- Consolidate land and properties in close proximity to build operating efficiency; and
- Manage asset and drilling portfolios closely, assessing value to the company and making changes where needed.

Research and Development

We have not expended any resources on pursuing research and development initiatives. We use existing technology and processes for executing our business plan.

Marketing and Major Customers

Colombia

Our oil in Colombia is good quality light oil, with 95% of production coming from the Putumayo Basin with an average API of 29° to 30°. Ecopetrol is the purchaser of most of our Colombia crude oil production and the source of the majority of our revenues. Sales to Ecopetrol accounted for 74%, 87% and 96%, of our consolidated revenues in 2012, 2011 and 2010, respectively.

We have entered into agreements to sell to Ecopetrol the volume of crude oil production produced in the Chaza Block, Santana Block and Guayuyaco Block (the "Putumayo production"). The volume of crude oil does not include the volume of oil owned by the ANH corresponding to royalties, other than HPR royalties. These agreements are subject to renegotiation periodically and generally contain mutual termination provisions with 30 days' notice. The expiry dates of these agreements have been extended multiple times, and will expire November 30, 2013. In the event that Ecopetrol does not accept a full delivery of this production, we may sell to another party the crude oil not accepted. We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and trucking.

Prior to the end of January 2012, the sales point for our sales to Ecopetrol of the Putumayo production to be exported through the Port of Tumaco on the Pacific coast of Colombia was a point in the Putumayo Basin. Beginning in February 2012, the sales point was changed to the Port of Tumaco. Due to the change in the sales point for Putumayo production to the Port of Tumaco, we entered into crude oil transportation agreements with Ecopetrol pursuant to which we pay to Ecopetrol a transportation tariff and transportation tax for the transportation by Ecopetrol of the Putumayo production from the Putumayo Basin to the Port of Tumaco. Under these agreements, Ecopetrol is liable for risk of loss of oil during transportation only if Ecopetrol fails to take reasonable measures to operate the pipeline or is grossly negligent. Currently we have Firm Capacity Transportation Agreements for 6,000 BOPD that are in place for eight years and the remainder of our Putumayo production is transported through the spot agreements. The later agreements are due to expire on June 30, 2013, but contemplate the transfer of pipeline assets to a wholly owned subsidiary of Ecopetrol, CENIT S. A. S. ("CENIT"), at which time Ecopetrol will assign the transportation agreements, as so amended, to CENIT.

In the event Ecopetrol does not accept a full delivery of our production, we have three alternative purchasers: Gunvor Colombia SAS ("Gunvor"), Petrobras Colombia Limited ("Petrobras Colombia") and one other short-term customer. Sales to Gunvor, Petrobras Colombia and the short-term customer accounted for 2%, 4% and 6% of our consolidated revenues during the year ended December 31, 2012, respectively.

During January 2013, we sold approximately 7,500 BOPD to Gunvor. We are under no obligation to sell any oil to Gunvor until we specify for a particular day the amount of oil we wish to sell to them. Oil is delivered to Gunvor at the Costayaco battery and the sales point is where the oil is loaded into a truck at our loading facility. The Gunvor agreements will expire on December 2, 2013. Oil is delivered to Petrobras Colombia at facilities at Guaduas or Vasconia Station and this is the sales point. We are under no obligation to sell any oil to Petrobras Colombia. Our third short-term customer in Colombia permits us to use excess capacity on their pipeline to transport our oil to the Port of Coveñas up to a maximum of 5,000 BOPD with no minimum volume obligation. For this customer, the delivery point is when the oil is loaded into their trucks, but the sales point is when oil is loaded into their export tanker, which is subject to the export program and off-take procedures of the port of Coveñas.

The majority of the oil produced is transported by pipeline. Varying amounts of oil are trucked: (1) from Santana Station to Ecopetrol's storage terminal at Orito, a distance of approximately 46 kilometers, (2) from the Costayaco field to Ecopetrol's storage terminal at Neiva (Dina Station), approximately 350 kilometers north of the Chaza Block, (3) from the Costayaco field to the Atlántico Oil Terminal in Barranquilla, a distance of approximately 1,500 kilometers, (4) from the Garibay field to facilities at Vasconia Station, a distance of approximately 640 kilometers and (5) during 2012, from the Costayaco field to our short-term customer's facilities at Rio Loro Station, approximately 220 kilometers north of the field.

Oil prices for sales to Ecopetrol are defined by agreements with Ecopetrol based on a "marker" price (generally the average export price for crude oil from the port of shipment) with adjustments for quality and specified fees depending on the port, including a port operation fee and a commercialization fee, and a transportation fee and transportation tax. Oil prices for sales to Gunvor are based on the average of WTI prices plus a Vasconia differential and premium, adjusted for trucking costs. Oil prices for sales to Petrobras Colombia are based on Vasconia crude oil price less adjustments for quality, transportation, marketing and handling. Oil prices for sales to our additional short-term purchaser are determined based on Vasconia crude oil price less adjustments for quality, transportation, marketing and handling. We receive revenues for our Colombian oil sales in U.S. dollars.

Argentina

We market our own share of production in Argentina. The purchaser of our oil in the Noroeste Basin of Argentina is Refineria del Norte S.A. ("Refinor"). Our contract with Refinor expired on January 1, 2008; however, we are continuing sales of our oil under monthly agreements with Refinor. In the Noroeste Basin, oil is delivered to the refinery by truck.

At December 31, 2012, Shell C.A.P.S.A. ("Shell") and YPF S.A. ("YPF") were the main purchasers of our oil in the Neuquen Basin of Argentina. In the Neuquen Basin, oil is delivered to the refinery by pipeline.

Sales to Refinor and Shell accounted for 6% and 3%, respectively, of our oil and natural gas sales in 2012. Sales to Refinor and Shell each accounted for 3% of our oil and natural gas sales in 2011 and sales to Refinor accounted for 4% of our oil and natural gas sales in 2010. The purchaser of our gas in Argentina is Albanesi S.A. Sales to Albanesi S.A. accounted for less than 1% of our oil and natural gas sales in 2012 and 2011 and were nil in 2010.

In Argentina, export prices for oil are subject to an export withholding tax based on WTI price. This export tax has the effect of limiting the actual realized price for sales. Our oil prices are agreed on a spot basis, based on WTI price less adjustments for quality, transportation and an adjustment similar to the export tax. We receive revenues in Argentina pesos, based on U.S. dollar prices at the exchange rate on the payment date.

Brazil

Petróleo Brasileiro S.A ("Petrobras") is the purchaser of most of the oil produced from Block 155 in Brazil. Oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. During 2012, oil prices for sales to Petrobras were based on the monthly average Brent DTD price less $11.15 per barrel. Pursuant to the 2013 oil sales contract with Petrobras, oil prices will be based on the monthly average Brent DTD price less $13.19 per barrel.

There were no sales in any countries other than Colombia, Argentina and Brazil in 2012, 2011 and 2010.

See "Guerrilla Activity in Colombia Has Disrupted and Delayed, and Could Continue to Disrupt or Delay, Our Operations and We Are Concerned About Safeguarding Our Operations and Personnel in Colombia", "Our Oil Sales Will Depend on a Relatively Small Group of Customers, Which Could Adversely Affect Our Financial Results," and "Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations", "Negative Political Developments in Peru May Negatively Affect our Proposed Operations," "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" and other risk factors in the section entitled "Risk Factors" for a description of the risks faced by our dependency on a small number of customers and the regulatory systems under which we operate.

Competition

The oil and gas industry is highly competitive. We face competition from both local and international companies in acquiring properties, contracting for drilling and other oil field equipment and securing trained personnel. Many of these competitors have financial and technical resources that exceed ours, and we believe that these companies have a competitive advantage in these areas. Others are smaller, and we believe our technical and financial capabilities give us a competitive advantage over these companies. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, there is substantial competition for prospects and resources in the oil and gas industry.

See "Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business" in the section entitled "Risk Factors" for risks associated with competition.

Geographic Information

Information regarding our geographic segments, including information on revenues, assets, expenses, and net income can be found in Note 4 to the Financial Statements, Segment and Geographic Reporting, in the section entitled "Financial Statements and Supplementary Data". Long lived assets are Property, Plant and Equipment, which includes all oil and gas assets, furniture and fixtures, automobiles and computer equipment. No long lived assets are held in our country of domicile, which is the United States of America. 'All Other' assets include assets held by our corporate head office in Calgary, Alberta, Canada. Because all of our exploration and development operations are in South America, we face many risks attendant with these operations. See the section entitled "Risk Factors" for risks associated with our foreign operations.

Regulation

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

Colombia

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

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

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

Gran Tierra operates in Colombia through two branches – Gran Tierra Energy Colombia, Ltd. and Petrolifera Petroleum (Colombia) Limited. Both are qualified as operators of oil and gas properties by ANH.

When operating under a contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, and pays royalties which are collected by ANH or Ecopetrol, depending on the type of contract. The contractor can market the hydrocarbons in any manner whatsoever, subject to a limitation in the case of natural emergencies where the law specifies the manner of sale.

Argentina

The Hydrocarbons Law 17.319, enacted in June 1967, established the basic legal framework for the regulation of exploration and production of hydrocarbons in Argentina. The Hydrocarbons Law empowers the National Executive Branch to establish a national policy for development of Argentina's hydrocarbon reserves, with the main purpose of satisfying domestic demand. However, on January 5, 2007, Law 26.197 was passed by the Government of Argentina. This legal framework replaced article one of the Hydrocarbons Law 17.319 and provides for the provinces to assume complete ownership, authority and administration of the oil and natural gas reserves located within their territories, including offshore areas up to 12 marine miles from the coast line. This includes all exploration permits and exploitation and transportation concessions.

On June 3, 2002, the Government of Argentina issued a resolution authorizing the Energy Secretariat to limit the amount of oil that companies can export. The restriction was to be in place from June 2002 to September 2002. However, on June 14, 2002, the government agreed to abandon the limit on oil export volumes in exchange for a guarantee from oil companies that domestic demand will be supplied. Oil companies also agreed not to raise natural gas and related prices to residential customers during the winter months and to maintain gasoline, natural gas and oil prices in line with those in other South American countries.

Near the end of 2007, the Government of Argentina issued decrees changing the withholding export tax structure and further regulating oil exports.

At the end of 2008, the Argentina government launched the Gas Plus and Petroleum Plus programs, programs designed to stimulate investments in and production of natural gas and oil through providing incentives for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields. Companies must apply for the incentives, and qualification is based on a complex set of formulas involving increased production over a calculated base and increases in proved reserves for the year. Gran Tierra has received credits totaling $2.6 million under the Petroleum Plus program related to our production for the first, third and fourth quarters of 2010 and the first quarter of 2008. Claims are pending for certain other quarters in 2011, 2010 and 2009. Realization of the credits is contingent on Gran Tierra establishing a contract with a third party to purchase the credits or exporting oil. We are negotiating with other parties for the sale of other credits.

In October 2010, the Argentina Gas Authority ("ENARGAS") issued Regulation I-1410 aimed at securing the supply of natural gas to residential consumers and small industry given the decline in gas production and the expected growing demand for gas. The regulation includes all the procedures created by the authorities since 2004 (restrictions of exports, deviation of gas sales to residential consumption) and gives ENARGAS power to control gas marketing in order to assure the supply of gas to residential consumers and small industry. This regulation is being challenged by gas producers on the grounds that it illegally interferes in their gas marketing activities.

After general elections in October 2011, the Government of Argentina decided to remove certain subsidies which were implemented after the 2001/2002 Argentina economic crisis. Consequently, in November 2011, ENARGAS issued Regulation 1982 which broadened the application of a charge to certain industries and services, including oil & gas upstream and natural gas processing activities, and increased the charge. The charge was created in 2008 to fund the importation of natural gas and liquefied natural gas into Argentina. This measure is expected to negatively impact the oil and gas industry in Argentina and has been challenged by some important companies within the industry.

In July 2012, the Argentina government mandated the creation of an oil planning commission that will set national energy goals and have the power to review private oil companies' investment plans. Private companies must submit an annual investment plan by September 30 of each year. The committee will have the power to approve or reject the annual investment plan.. This decree is new and many details are yet to be announced. However, we believe there is a risk that this may cause delays in our operations in Argentina, or cause changes to our investment plans that could negatively affect our business in Argentina or the rest of our operations.

Additionally in Argentina some provincial regulations are changing, introducing new royalties and fees associated with extensions of concession agreements.

Gran Tierra operates in Argentina through Gran Tierra Energy Argentina S.R.L. and two branches: Petrolifera Petroleum (Americas) Limited – Sucursal Argentina and Petrolifera Petroleum Limited – Sucursal Argentina. Gran Tierra Energy Argentina S.R.L. and Petrolifera Petroleum (Americas) Limited – Sucursal Argentina are qualified by the Federal Secretary of Energy to be titleholders of Exploration Permits and Exploitation Concessions as well as to operate them. Petrolifera Petroleum Limited – Sucursal Argentina is qualified to be a titleholder of Exploration Permits and Exploitation Concessions, but not to operate them.

See "Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations" in the section entitled "Risk Factors" for a description of the risks associated with Argentina government controls.

Peru

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

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

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

Gran Tierra operates in Peru through Gran Tierra Energy Peru S.R.L. and Petrolifera Petroleum Del Peru S.A.C. Gran Tierra has been qualified by PeruPetro with respect to our contracts for Blocks 95, 123 and 129 and Petrolifera has been qualified by PeruPetro with respect to our contracts for Blocks 107 and 133.

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

See "Negative Political Developments in Peru May Negatively Affect our Proposed Operations" in the section entitled "Risk Factors" for a description of the risks associated with the political climate in Peru.

Brazil

In Brazil, Law No. 2004 enacted in 1953 created the state monopoly of the petroleum industry and Petrobras, a state-owned legal entity, which was the sole company conducting exploration and production activities in Brazil.

Amendment No. 9 to the Brazilian Constitution, enacted on November 9, 1995, authorized the Brazilian government to contract with state and private companies, with head offices and management located in Brazil, for the exploration and production of oil and natural gas, as well as to grant authorizations for the refining, transportation, import and export of oil, natural gas and its by-products, discontinuing Petrobras' exclusive right to explore and produce petroleum and natural gas in Brazil.

The regulatory model is governed by Law No. 9478 of August 6, 1997 (the "Petroleum Law"), as amended, which controls the granting of concessions for carrying out exploration and production activities to Brazilian companies. The Petroleum Law, as amended, also established a legal framework for pre-salt layer areas and strategic areas to be defined by the Brazilian government and which will be subject to the Production Sharing Regime.

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

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

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

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

Concessionaires are required under Law No. 9478 to pay the government dues and fees, in addition to the charges for sale of pre-bid data and information. ANP has the power to determine the criteria under which the Government Take will be assessed within the limits established by Decree No. 2,705/98. Government Take comprises (i) signature bonus, (ii) royalties, (iii) special participation and (iv) area rentals. Part of the Government Take is passed on to States and Municipalities and other government branches according to law.

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

See the section entitled "Risk Factors" for information regarding the regulatory risks that we face.

Environmental Compliance

Our activities are subject to existing laws and regulations governing environmental quality and pollution control in the foreign countries where we maintain operations. Our activities with respect to exploration, drilling and production from wells, facilities, including the operation and construction of pipelines, plants and other facilities for transporting, processing, treating or storing oil and other products, are subject to stringent environmental regulation by provincial and federal authorities in Colombia, Argentina, Peru and Brazil. Such regulations relate to environmental impact studies, permissible levels of air and water emissions, control of hazardous wastes, construction of facilities, recycling requirements, reclamation standards, among others. Risks are inherent in oil and gas exploration, development and production operations, and significant costs and liabilities may be incurred in connection with environmental compliance issues. All licenses and permits which we may require to carry out exploration and production activities may not be obtainable on reasonable terms or on a timely basis, and such laws and regulations may have an adverse effect on any project that we may wish to undertake.

In 2013, we plan to spend approximately $12.0 million in Colombia on capital programs related to environmental studies, community consultations and environmental remediation. In Peru, costs for environmental and social projects are expected to be approximately $6.0 million which mainly relates to environmental and social impact assessments, implementation of environmental management plans, and environmental and social monitoring activities. We plan to spend approximately $1.2 million in Argentina on programs related to environmental matters, including environmental studies, water treatment and chemical storage facilities. In Brazil, we plan to spend approximately $0.9 million on costs for environmental projects.

In 2012, we experienced a limited number of environmental incidents and enacted the following environmental initiatives:

- In Colombia, oil was released from a flow through drainage chamber in the Mary battery. We have taken measures to contain the release, are continuing to investigate the source of the release and plan to start remediation activities. The remainder related to the integrity of materials, the rollover of two oil transportation trucks and the installation of illegal valves. A number of minor incidents on our blocks occurred, each of which caused small quantities of oil to be spilled. In each of these minor incidents, we completed a full clean up and remediation of the affected area.
- In Argentina, minor spills occurred relating to pipeline corrosion, an overflowing storage tank and other incidents. In each case, we completed a full clean up and remediation of the affected area.
- In Peru, we continued the Environmental Monitoring Program for drilling activity on Block 95 and pursued an agreement with the Pacaya Samiria Natural Reserve. We are also seeking the necessary permits for the relocation of four well pads and a seismic project in Block 107 and we began preparations for an Environmental Impact Study for seismic and drilling activities on Block 133.
- In Brazil, we obtained the necessary licenses for pipelines to connect our wells on Block 155 and are developing a water, soil and air monitoring program.

We will continue to strive to be in compliance with all environmental and pollution control laws and regulations in Colombia, Argentina, Peru and Brazil. We plan to continue enacting environmental, health and safety initiatives in order to minimize our environmental impact and expenses.

We also plan to continue to improve internal audit procedures and practices in order to monitor current performance and search for improvement.

We expect the cost of compliance with federal, state and local provisions which have been enacted or adopted regulating the discharge of materials into the environment, or otherwise relating to the protection of the environment for the remainder of our operations, will not be material to Gran Tierra.

We have implemented a company wide web based reporting system which allows us to better track incidents and respective corrective actions and associated costs. We have a Corporate Health, Safety and Environment Management System and follow Environmental Best Practices. We have an environmental risk management program in place as well as a waste management system. Air and water testing occur regularly, and environmental contingency plans have been prepared for all sites and ground transportation of oil. We have a regular quarterly comprehensive reporting system, with a schedule of internal audit and routine checking of practices and procedures. Emergency response exercises were conducted in Calgary, Argentina, Colombia, Peru and Brazil.

Community Relation Initiatives

In 2012, we continued standardized, quarterly reporting on our community relation initiatives. We also continuously monitor the needs of the communities where we operate to ensure that our investments meet their requirements and have the highest impact possible.

In addition to employing local people and hiring local companies as often as feasible in all of our operations, we have a program of community investment in all of our operating areas. Projects undertaken in 2012 were as follows:

Colombia

In 2012, our most significant community relations initiatives and investments were made in the Costayaco, Moqueta, Santana and Guayuyaco fields. We made voluntary investments in relation to community support during drilling projects on the Chaza, Sierra Nevada, Turpial, Azar, and Guepaje Blocks during the year and during the Rumiyaco 3-D seismic project. Below is a description of our $2.3 million voluntary social investment, responding to the needs identified and prioritized by the communities in those areas in which we operate.

- Provided support for education, including providing tuition, supplies and transportation for students in all levels of education.
- Supported community groups in projects that benefited local families with agriculture and fisheries projects.
- Provided fiscal support, construction of facilities, transportation of materials and other expertise to projects.
- Various projects for the support of cultural identity such as sponsorship of local festivals that celebrate indigenous culture and history and sponsorship of local people to attend a conference of indigenous peoples from various areas in the country.
- Various programs for strengthening local infrastructure such as paving streets in urban areas, construction of culture rooms, fencing at schools, construction of sport facilities and computer rooms, and provision of materials for electric power supply in rural areas.
- Projects related to health, basic sanitation and housing including improving health facilities, health brigades, and remodeling and equipment of health centers.
- Provided strong communications with the communities and undertook prior consultations with ethnic minorities.

Argentina

In 2012, we invested approximately $0.6 million in the following activities:

- Provided and distributed education materials to schools in our operated areas and ran health and environment workshops with students.
- Created school vegetable gardens and chaguar experimental farming
- Provided training to teachers and students in health education.
- Provided basic life necessities (food, clothing, health support) to impoverished people in our operating areas.
- Delivered medicines to hospitals and supported medical care of children and pregnant women.
- Provided temporary employment to residents in several of our operating areas.
- Provided funds in support of beekeeping and crafts projects.
- Provided cattle guards to the landowners.
- Delivered drinking water to nearby families.
- Along with our joint venture partners in the Palmar Largo Block, several other initiatives were undertaken, including projects aimed at developing sustainable income for the communities in the area, fuel and security for local hospitals, and construction of reservoirs and water wells. These projects were operated by PlusPetrol S.A.
- A social survey was carried out in the Neuquen Basin in order to implement a social and community relations program. The program is expected to start during the first quarter 2013.

Peru

In 2012, we invested approximately $1.9 million in the following activities:

- Negotiated compensation arrangements with communities for the use of their lands. In Block 95, executed an agreement with the Bretaña town to improve electricity services and the health center.
- Held consultation and education sessions with various communities located on our blocks and developed technical workshops with indigenous organizations on the uses of natural resources.
- Provided healthcare support services to communities in our blocks.
- Provided temporary employment to residents in our blocks.

Brazil

In 2012, we invested approximately $150,000 in a compensation program with communities for use of their lands. We began work on landowner agreements and negotiated payments for carrying out seismic programs on their land. We completed the evaluation and development of a Corporate Social Responsibility ("CSR") project in the Pojuca Area. We completed an assessment of social initiatives and communities' needs, as well as stakeholder's strengths, in municipalities around Block 155. We developed and implemented the program "birds of my land" where children of the community named our Tiê field. We also undertook work to improve waste transportation.

Employees

At December 31, 2012, we had 485 full-time employees: 44 located in the Calgary corporate office, 275 in Colombia (137 staff in Bogota and 138 field personnel), 89 in Argentina (46 office staff in Buenos Aires and 43 field personnel, of which 26 were unionized), 44 in Peru (both field and office staff) and 33 in Brazil (21 office staff in Rio de Janeiro and Salvador and 12 field staff). Other than as disclosed above, none of our employees are represented by labor unions, and we consider our employee relations to be good.

Available Information

Our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q and current reports on Form 8-K, as well as any amendments to such reports and all other filings pursuant to Section 13(a) or 15(d) of the Exchange Act which we make available as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC, are available free of charge to the public on our website www.grantierra.com. To access our SEC filings, select SEC Filings from the investor relations menu on our website, which will provide a list of our SEC filings. Our website address is provided solely for informational purposes. We do not intend, by this reference, that our website should be deemed to be part of this Annual Report. Any materials we have filed with the SEC may be read and/or copied at the SEC's Public Reference Room at 100 F Street N.E. Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet site that contains reports, proxy and information statements, and other information regarding us. Our SEC filings are also available to the public at the SEC's website at www.SEC.gov.

Risk Factors

Risks Related to Our Business

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

During 2012, the guerrilla activity in Colombia has increased significantly. This increased activity creates a greater risk for our operations and our employees and our mitigation activities may not be adequate to alleviate the risks arising from such guerrilla activity.

For over 40 years, the Colombian government has been engaged in a civil war with two main Marxist guerrilla groups: the Revolutionary Armed Forces of Colombia ("FARC") and the National Liberation Army ("ELN"). Both of these groups have been designated as terrorist organizations by the United States and the European Union. Another threat comes from criminal gangs formed from the former members of the United Self-Defense Forces of Colombia ("AUC") militia, a paramilitary group that originally sprouted up to combat FARC and ELN, which the Colombian government successfully dissolved.

We operate principally in the Putumayo Basin in Colombia, and have properties in other basins, including the Catatumbo, Cauca, Llanos, Middle Magdalena and Lower Magdalena Basins. The Putumayo and Catatumbo regions have been the breeding place of guerrilla activity. Beginning in 1989, our predecessor company's facilities in one field were attacked by guerrillas and operations were briefly disrupted. In October 2010, two of our sites in the Putumayo/Cauca were attacked by FARC guerrillas causing some disruption to operations. Pipelines have also been primary targets because such pipelines cannot be adequately secured due to the sheer size of such pipelines and the remoteness of the areas in which the pipelines are laid. The Ecopetrol-operated OTA pipeline which transports oil from the Putumayo region and upon which we materially rely has been a target by these guerrilla groups. In March and April of 2008, June, July, August and October of 2009, June, August, and September of 2010, February 2011, February to August of 2012 and October 2012 to February 2013, sections of the OTA pipeline were sabotaged by guerrillas, which temporarily reduced our deliveries to Ecopetrol during the affected periods. In the year ended December 31, 2012, the OTA pipeline was shutdown for over 162 days and the shutdown has had a material adverse effect on our deliveries to Ecopetrol and our financial performance for 2012. We have employed mitigation strategies as discussed in the risk "*We May Encounter Difficulties Storing and Transporting Our Production, Which Could Cause a Decrease in Our Production or an Increase in Our Expenses*" later in this section. Such disruptions may continue indefinitely and could harm our business.

On January 30, 2013, four contract workers employed by companies providing services to Gran Tierra in the Putumayo Basin were abducted, possibly by guerillas. One individual was released within an hour, the other three contractor workers were returned unharmed the next day (January 31, 2013). No employees of Gran Tierra were involved in the incident. Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may continue to disrupt our operations in the future. Our efforts to increase security measures may not be successful and there can also be no assurance that we can maintain the safety of our or our contractors' field personnel and Bogota head office personnel or operations in Colombia or that this violence will not continue to adversely affect our operations in the future and cause significant loss.

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

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

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

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

The majority of our oil in Colombia is delivered by a single pipeline to Ecopetrol and sales of oil have been and could continue to be disrupted by damage to this pipeline or displaced by Ecopetrol's use of the pipeline itself. Starting in February 2012, we are operating under a new transportation contract with Ecopetrol which changes the point at which Ecopetrol takes delivery of our oil. Previously, Ecopetrol took delivery of our oil at the beginning of the export pipeline. Under the new transportation contract, Ecopetrol takes delivery at the end of the export pipeline. This creates a risk of loss of oil due to sabotage by guerrillas or theft from the pipeline which may result in reduced revenues and increased clean-up or third party costs. We have attempted to mitigate the risk of increased costs with insurance and are investigating potential ways to mitigate and reduce revenue risk. Ecopetrol maintains responsibility for clean-up of any spilled oil and for pipeline repair.

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, June, July and August of 2009, June, August, and September 2010, February 2011, February to August of 2012 and October 2012 to February 2013 as a result of sabotage by guerrillas. In addition, there is competition for space in these pipelines, and additional discoveries in our area of operations by other companies could decrease the pipeline capacity available to us. Trucking is an alternative to transportation by pipeline; however, it is generally more expensive and carries higher safety risks for us, our employees and the public.

As some of our oil production in Argentina is trucked to a local refinery, sales of oil in the Noroeste Basin can be delayed by adverse weather and road conditions, particularly during the months November through February when the area is subject to periods of heavy rain and flooding. While storage facilities are designed to accommodate ordinary disruptions without curtailing production, delayed sales will delay revenues and may adversely impact our working capital position in Argentina. Furthermore, a prolonged disruption in oil deliveries could exceed storage capacities and shut-in production, which could have a negative impact on future production capability.

Recent alternative transportation arrangements in Colombia allowed us to deliver our full production in January 2013; however, these deliveries carried higher transportation costs than the Ecopetrol operated OTA pipeline transportation costs and are not necessarily sustainable. When disruptions are of a long enough duration, our sales volumes may be lower than normal, which will cause our cash flow to be lower than normal, and if our storage facilities become full, we can be forced to reduce production.

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

Oil sales in Colombia are mainly to Ecopetrol. While oil prices in Colombia are related to international market prices, lack of competition and reliance on a limited number of customers for sales of oil may diminish prices and depress our financial results.

The entire Argentina domestic refining market is small and export opportunities are limited by available infrastructure. As a result, our oil and gas sales in Argentina will depend on a relatively small group of customers, and currently, on two significant customers. The lack of competition in this market could result in unfavorable sales terms which, in turn, could adversely affect our financial results. Currently, all operators in Argentina are operating without long-term sales contracts. We cannot provide any certainty as to when the situation will be resolved or what the final outcome will be.

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

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

We operate our business in Colombia, Argentina, Peru, and Brazil, and may eventually expand to other countries. Exploration and production operations in foreign countries are subject to legal, political and economic uncertainties, including terrorism, military repression, social unrest, strikes by local or national labor groups, interference with private contract rights (such as privatization), extreme fluctuations in currency exchange rates, high rates of inflation, exchange controls, changes in tax rates, changes in laws or policies affecting environmental issues (including land use and water use), workplace safety, foreign investment, foreign trade, investment or taxation, as well as restrictions imposed on the oil and natural gas industry, such as restrictions on production, price controls and export controls. For example, starting on November 21, 2008, we were forced to reduce production in Colombia on a gradual basis, culminating on December 11, 2008, when we suspended all production from the Santana, Guayuyaco and Chaza blocks in the Putumayo Basin. This temporary suspension of production operations was the result of a declaration of a state of emergency and force majeure by Ecopetrol due to a general strike in the region. In January 2009, the situation was resolved and we were able to resume production and sales shipments. Starting in 2010, there was an increased presence of illegitimate unionization activities in the Putumayo Basin by the *Sindicato de Trabajadores Petroleros del Putumayo*, which disrupted our operations from time to time and may do so in the future. During 2012 and 2011, Argentina has experienced increased union activity and this may create disruptions in our Argentina operations in the future. During 2012 and 2013, we have also experienced related issues with landowners blocking access to our fields for short periods of time in Argentina. South America has a history of political and economic instability. This instability could result in new governments or the adoption of new policies, laws or regulations that might assume a substantially more hostile attitude toward foreign investment, including the imposition of additional taxes. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets. Any changes in oil and gas or investment regulations and policies or a shift in political attitudes in Argentina, Colombia, Peru or Brazil or other countries in which we intend to operate are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit.

For instance, changes in laws in the jurisdiction in which we operate or expand into with the effect of favoring local enterprises, and changes in political views regarding the exploitation of natural resources and economic pressures, may make it more difficult for us to negotiate agreements on favorable terms, obtain required licenses, comply with regulations or effectively adapt to adverse economic changes, such as increased taxes, higher costs, inflationary pressure and currency fluctuations. In certain jurisdictions the commitment of local business people, government officials and agencies and the judicial system to abide by legal requirements and negotiated agreements may be more uncertain, creating particular concerns with respect to licenses and agreements for business. These licenses and agreements may be susceptible to revision or cancellation and legal redress may be uncertain or delayed. Property right transfers, joint ventures, licenses, license applications or other legal arrangements pursuant to which we operate may be adversely affected by the actions of government authorities and the effectiveness of and enforcement of our rights under such arrangements in these jurisdictions may be impaired.

In July 2012, the Argentina government mandated the creation of an oil planning commission that will set national energy goals and have the power to review private oil companies' investment plans. Private companies must submit an annual investment plan by September 30 of each year. The committee will have the power to approve or reject the annual investment plan.. This decree is new and many details are yet to be announced. However, we believe there is a risk that this may cause delays in our operations in Argentina, or cause changes to our investment plans that could negatively affect our business in Argentina or the rest of our operations.

Additionally in Argentina, some provincial regulations are changing, introducing new royalties and fees associated with extensions of concession agreements. These royalties and fees represent increased costs for the affected concessions, specifically our Rio Negro Province concession, which could result in a decreased rate of return from this asset and could negatively affect our business in Argentina.

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

Our capital program for 2013 calls for approximately $363 million to fund our exploration and development, which we intend to fund through existing cash, cash flows from operations and potential periodic draws from our revolving credit facility. Funding this program relies in part on oil prices remaining high and other factors to generate sufficient cash flow. If we are not able to generate the sales which, together with our current cash resources, are sufficient to fund our capital program, we will not be able to efficiently execute our business plan which would cause us to decrease our exploration and development, which could harm our business outlook, investor confidence and our share price.

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

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

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

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

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

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

Disputes or Uncertainties May Arise in Relation to our Royalty Obligations

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

In accordance with our Hydrocarbon Exploration and Exploitation Agreement with ANH for the Chaza Block in Colombia our oil production from each Exploitation Area on the Block is subject to the payment of additional compensation to the ANH over and above the basic sliding scale royalty that applies when cumulative gross production from an Exploitation Area exceeds five MMbbl. Production from the Costayaco Exploitation Area on the Chaza Block became subject to this additional compensation in the fourth quarter of 2009 after cumulative production from the Costayaco field exceeded five MMbbl.

The ANH has requested that the additional compensation be paid with respect to production from the recently drilled wells relating to the Moqueta discovery and has initiated a noncompliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, we view the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is our view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five MMbbl. Discussions with the ANH have not resolved this issue and we have sent notice to the ANH to initiate the dispute resolution process prescribed by the Chaza Contract. No assurance can be made that our interpretation will prevail and, depending on the ultimate size of the cumulative production from the Moqueta field in the future, such amounts may be material if such additional compensation must be paid. As at December 31, 2012, total cumulative production from the Moqueta field was 0.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $15.1 million. At this time no amount has been accrued in the financial statements nor deducted from our reserves for the disputed royalty as Gran Tierra does not consider it probable that a loss will be incurred.

In Brazil, a new regulatory regime was introduced; however, the royalty distribution between producing states has not been approved.

Negative Political and Regulatory Developments in Argentina May Negatively Affect our Operations.

The oil and natural gas industry in Argentina is subject to extensive regulation including land tenure, exploration, development, production, refining, transportation, and marketing, imposed by legislation enacted by various levels of government and, with respect to pricing and taxation of oil and natural gas, by agreements among the federal and provincial governments, all of which are subject to change and could have a material impact on our business in Argentina. The Federal Government of Argentina has implemented controls for domestic fuel prices and has placed a tax on oil and natural gas exports.

In October 2010, ENARGAS issued Regulation I-1410 aiming at securing the supply of natural gas to residential consumers and small industry given the decline in gas production and the expected growing demand for gas. The regulation includes all the procedures created by the authorities since 2004 (restrictions of exports, deviation of gas sales, to residential consumption) and gives ENARGAS power to control gas marketing in order to assure the supply of gas to residential consumers and small industry.

Any future regulations that limit the amount of oil and gas that we could sell or any regulations that limit price increases in Argentina and elsewhere could severely limit the amount of our revenue and affect our results of operations.

Currently most oil and gas producers in Argentina are operating without sales contracts. In 2008, a new withholding tax regime for exports was introduced without specific guidance as to its application. The domestic price was regulated in a similar way, so that both exported and domestically sold products were priced the same. Producers and refiners of oil in Argentina were unable to determine an agreed sales price for oil deliveries to refineries. In our case, the refineries' price offered to oil producers reflects their price received, less taxes and operating costs and their usual mark up. Along with most other oil producers in Argentina, we are continuing negotiating sales on a spot price basis with refiners and the price is negotiated on a month by month basis. The Provincial governments have also been hurt by these changes as their effective royalty and turnover tax takes have been reduced and capital investment in oilfields has declined, and so they are lobbying to change the situation. The government introduced the Petro Plus and Gas Plus programs in 2009, which grant higher prices to producers that sell production from new reserves. This is a positive step forward that will hopefully lead to further opening of price regulation in Argentina.

Recently, the government of Argentina has been active in the oil and gas business. On April 16, 2012, the government announced their intention to acquire a 51% interest in YPF S.A. ("YPF") from Repsol S.A. (Repsol S.A. holds 56.7% of YPF), and retain 51% control for the Federal Government and distribute 49% of the shares to Argentina provinces. During 2012, the Argentina government took control of YPF's operations and signed deals with Chevron Corporation and others for developing shale resources. Repsol S.A. has filed international complaints and US lawsuits regarding the takeover and subsequent deals. Prior to this announcement, various provincial governments announced contract cancellations effecting YPF, Petrobras Argentina S.A., and Azabache Energy Inc., among others. The reason cited for the contract cancellations was lack of activity in the areas in question. We have experienced recent success in Argentina and have active programs in all areas, which we believe helps mitigate our risk. However, despite the fact that our operating entity in Argentina is a locally incorporated company the employees of which are all Argentine, we are viewed as a foreign company and could therefore face increased risk.

In July 2012, the Argentina government mandated the creation of an oil planning commission that will set national energy goals and have the power to review private oil companies' investment plans. The committee will have the power to approve or reject annual investment plans that must be submitted by private companies by September 30 of each year. This decree is new and many details are yet to be announced. However, we believe there is a risk that this may cause delays in our operations in Argentina, or cause changes to our investment plans that could negatively effect our business in Argentina or the rest of our operations.

Additionally in Argentina some provincial regulations are changing, which are introducing new royalties and fees associated with extensions of concession agreements. These royalties and fees represent increased costs for the affected concessions, specifically our Rio Negro Province concession, which could result in decreased rates of returns from this asset.

Our Business May Suffer If We Do Not Attract and Retain Talented Personnel.
Our success will depend in large measure on the abilities, expertise, judgment, discretion, integrity and good faith of our executive team and other personnel in conducting our business. The loss of any of these individuals or our inability to attract suitably qualified individuals to replace any of them could materially adversely impact our business. We are experiencing difficulties in finding and retaining suitably qualified staff in certain jurisdictions, particularly in Brazil and Peru, where experienced personnel in our industry are in high demand and competition for their talents is intense.

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

Competition in Obtaining Rights to Explore and Develop Oil and Gas Reserves and to Market Our Production May Impair Our Business.
The oil and gas industry is highly competitive. Other oil and gas companies will compete with us by bidding for exploration and production licenses and other properties and services we will need to operate our business in the countries in which we expect to operate. Additionally, other companies engaged in our line of business may compete with us from time to time in obtaining capital from investors. Competitors include larger companies, which, in particular, may have access to greater resources than us, may be more successful in the recruitment and retention of qualified employees

and may conduct their own refining and petroleum marketing operations, which may give them a competitive advantage. In addition, actual or potential competitors may be strengthened through the acquisition of additional assets and interests. In the event that we do not succeed in negotiating additional property acquisitions, our future prospects will likely be substantially limited, and our financial condition and results of operations may deteriorate.

Foreign Currency Exchange Rate Fluctuations May Affect Our Financial Results.

We expect to sell our oil and natural gas production under agreements that will be denominated in U.S. dollars. Many of the operational and other expenses we incur will be paid in the local currency of the country where we perform our operations. Our income taxes in Colombia are paid in Colombian pesos. Our production in Argentina is primarily invoiced in U.S. dollars, but payment is made in Argentina pesos, at the then current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. Since September 1, 2005, exchange rates between the Colombian peso and U.S. dollar have varied between 1,648 pesos to one U.S. dollar to 2,632 pesos to one U.S. dollar, a fluctuation of approximately 60%. Since we began operating in Argentina (September 1, 2005), the rate of exchange between the Argentina peso and U.S. dollar has varied between 3.05 pesos to one U.S. dollar to 4.92 pesos to the U.S. dollar, a fluctuation of approximately 61%. Production in Brazil is invoiced and paid in Brazilian Reals. Since September 1, 2005, the exchange rate of the Brazilian Real has varied between 1.56 Reals to one U.S. dollar to 2.45 Reals to the U.S. dollar, a variance of 57%. Current and deferred tax liabilities in Colombia are denominated in Colombian pesos and the strengthening of 9.0% in the Colombian Peso against the U.S. dollar in the year ended December 31, 2012, resulted in a foreign exchange loss.

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

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

The governments in Brazil and Argentina require us to register funds that enter and exit the country with the central bank in each country. In Brazil, Argentina and Colombia, all transactions must be carried out in the local currency of the country. Exchange controls may prevent us from transferring funds abroad. For example, the Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentina subsidiaries to make dividend or loan payments to us and there may be a tax imposed with respect to the expatriation of such proceeds.

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

Tax law changes can impact the way we provide cross-border funding to our operating subsidiaries, as well as impact the after tax profits available for expatriation. For example, beginning in 2013, the Colombian rate of tax applicable to ordinary income derived by our Colombian operations has changed for the 3-year period 2013-2015 from 33% to 34%. Also in Colombia, beginning in 2013, a new definition of dividends is applied for branches. In this case, the transfer of branch profits are considered as dividends subject to a 25% tax if those dividends have not already been subject to Colombian tax. We do not currently expect that this change in Colombian law will have a material consequence.

Maintaining Good Community Relationships and Being a Good Corporate Citizen may be Costly and Difficult to Manage.

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

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

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

Further, we operate in remote areas and may rely on helicopter, boats or other transport methods. Some of these transport methods may result in increased levels of risk and could lead to operational delays, serious injury or loss of life and could have a significant impact on our reputation.

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

Peru held a national election in June 2011 after which a new political regime was elected, led by the left-populist candidate, Ollante Humala, who was elected the President. Mr. Humala has noted that the past decade prioritized the strengthening of democracy with economic growth, while the new government will enhance social inclusion to benefit the neediest. This political regime may adopt new policies, laws and regulations that are more hostile toward foreign investment which may result in the imposition of additional taxes, the adoption of regulations that limit price increases, termination of contract rights, or the expropriation of foreign-owned assets. While we do not have any reserves or any producing wells in Peru at this time, we do hold significant land holdings in Peru and such actions by the elected political regime could limit the amount of our future revenue in that country and affect our results of operations.

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

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

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

Each of these consequences could result in adverse economic consequences in Colombia and could further heighten the political and economic risks associated with our operations there. Any changes in the holders of significant government offices could have adverse consequences on our relationship with ANH and Ecopetrol and the Colombian government's ability to control guerrilla activities and could exacerbate the factors relating to our foreign operations. Any sanctions imposed on Colombia by the United States government could threaten our ability to obtain necessary financing to develop the Colombian properties or cause Colombia to retaliate against us, including by nationalizing our Colombian assets.

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

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

We expect that our existing cash resources and the availability to draw cash under our credit agreement will be sufficient to fund our currently planned activities. We may require additional capital to expand our exploration and development programs to additional properties. We may be unable to obtain additional capital required.

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

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

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

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

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

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

Risks Related to Our Industry

Unless We are Able to Replace Our Reserves, and Develop and Manage Oil and Gas Reserves and Production on an Economically Viable Basis, Our Reserves, Production and Cash Flows May Decline as a Result.
Our future success depends on our ability to find, develop and acquire additional oil and gas reserves that are economically recoverable. Without successful exploration, development or acquisition activities, our reserves and production will decline. We may not be able to find, develop or acquire additional reserves at acceptable costs.

To the extent that we succeed in discovering oil and/or natural gas, reserves may not be capable of production levels we project or in sufficient quantities to be commercially viable. On a long-term basis, our viability depends on our ability to find or acquire, develop and commercially produce additional oil and gas reserves. Without the addition of reserves through exploration, acquisition or development activities, our reserves and production will decline over time as reserves are produced. Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets. Future oil and gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-downs of connected wells resulting from extreme weather conditions, problems in storage and distribution and adverse geological and technical conditions. While we will endeavor to effectively manage these conditions, we may not be able to do so optimally, and we will not be able to eliminate them completely in any case. Therefore, these conditions could diminish our revenue and cash flow levels and result in the impairment of our oil and natural gas interests.

We are Required to Obtain Licenses and Permits to Conduct Our Business and Failure to Obtain These Licenses Could Cause Significant Delays and Expenses That Could Materially Impact Our Business.
We are subject to licensing and permitting requirements relating to exploring and drilling for and development of oil and natural gas, including seismic, environmental and many other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. For example, the permitting process in Peru takes significant time, meaning that exploration and development projects have a longer cycle time to completion than they might elsewhere. Other drilling projects are being delayed because the Ministry of the Environment has not increased staffing levels to meet increased activity in the oil and gas industry in Colombia and so permit processing takes longer than usual. These delays are also significantly impacting other industry participants. Regulations and policies relating to these licenses and permits may change, be implemented in a way that we do not currently anticipate or take significantly greater time to obtain. These licenses and permits are subject to numerous requirements, including compliance with the environmental regulations of the local governments. As we are not the operator of all the joint ventures we are currently involved in, we may rely on the operator to obtain all necessary permits and licenses. If we fail to comply with these requirements, we could be prevented from drilling for oil and natural gas, and we could be subject to civil or criminal liability or fines. Revocation or suspension of our environmental and operating permits could have a material adverse effect on our business, financial condition and results of operations. For example, currently in Brazil, we are subject to restrictions on flaring natural gas, which have the impact of limiting our production capacity.

Our Exploration for Oil and Natural Gas Is Risky and May Not Be Commercially Successful, Impairing Our Ability to Generate Revenues from Our Operations.
Oil and natural gas exploration involves a high degree of risk. These risks are more acute in the early stages of exploration. Our exploration expenditures may not result in new discoveries of oil or natural gas in commercially viable quantities. It is difficult to project the costs of implementing an exploratory drilling program due to the inherent uncertainties of drilling in unknown formations, the costs associated with encountering various drilling conditions, such as over pressured zones and tools lost in the hole, and changes in drilling plans and locations as a result of prior exploratory wells or additional seismic data and interpretations thereof. If exploration costs exceed our estimates, or if our exploration efforts do not produce results which meet our expectations, our exploration efforts may not be commercially successful, which could adversely impact our ability to generate revenues from our operations.

Estimates of Oil and Natural Gas Reserves that We Make May Be Inaccurate and Our Actual Revenues May Be Lower and Our Operating Expenses may be Higher than Our Financial Projections.
We make estimates of oil and natural gas reserves, upon which we will base our financial projections. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Economic factors beyond our control, such as interest rates and exchange rates, will also impact the value of our reserves. The process of estimating oil and gas reserves is complex, and will require us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. As a result, our reserve estimates will be inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and gas reserves may vary substantially from those we estimate. If actual production results vary substantially from our reserve estimates, this could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

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

If Oil and Natural Gas Prices Decrease, We May be Required to Take Write-Downs of the Carrying Value of Our Oil and Natural Gas Properties.
We follow the full cost method of accounting for our oil and gas properties. A separate cost center is maintained for expenditures applicable to each country in which we conduct exploration and/or production activities. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling is the estimated after tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price during the 12 months period prior to the ending date of the period covered by the balance sheet, calculated as an unweighted arithmetic average of the first-day-of-the month price for each month within such period for that oil and natural gas. That average price is

then held constant, except for changes which are fixed and determinable by existing contracts. The net book value is compared with the ceiling on a quarterly basis. The excess, if any, of the net book value above the ceiling is required to be written off as an expense. Under full cost accounting rules, any write-off recorded may not be reversed even if higher oil and natural gas prices increase the ceiling applicable to future periods. Future price decreases could result in reductions in the carrying value of such assets and an equivalent charge to earnings. In countries where we do not have proved reserves, dry wells drilled in a period would directly result in ceiling test impairment for that period.

In 2011, we recorded a ceiling test impairment loss of $42.0 million in our Peru cost center related to seismic and drilling costs on two blocks which were relinquished and a ceiling test impairment loss of $25.7 million in our Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. In 2012, we recorded a ceiling test impairment loss of $20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. The farm-out agreement for that block terminated during the first quarter of 2012 when we provided notice that we would not enter into the second exploration period.

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

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

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

There are risks associated with the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, premature declines of reservoirs, blow-outs, craterings, sour gas releases, fires and spills. Earthquakes or weather related phenomena such as heavy rain, landslides, storms and hurricanes can also cause problems in drilling new wells. There are also risks in producing oil and natural gas from existing facilities. For example, the Valle Morado GTE.St.VMor-2001 re-entry operations started in the third quarter of 2010, with integrity testing and remediation operations required for the sidetrack operations. Due to operational difficulties, the initial side-track attempt was not successful. The operation was placed on standby pending the arrival of additional side-track equipment and operations recommenced in the fourth quarter of 2010. In February 2011, these operations were suspended and the wellbore has been abandoned due to a number of operational challenges encountered. We continue to review alternatives associated with the field development. Also for example, on February 7, 2009, we experienced an incident at our Juanambu-1 well, involving a fire in a generator, resulting in total damage to equipment estimated at $500,000, and production in the amount of approximately $125,000 being deferred due to shutting down production facilities while dealing with the incident. The occurrence of any of these events could significantly reduce our revenues or cause substantial losses, impairing our future operating results. We may become subject to liability for pollution, blow-outs or other hazards. Incidents such as these can lead to serious injury, property damage and even loss of life. We generally obtain insurance with respect to these hazards, but such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. The payment of such liabilities could reduce the funds available to us or could, in an extreme case, result in a total loss of our properties and assets. Moreover, we may not be able to maintain adequate insurance in the future at rates that are considered reasonable. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including premature decline of reservoirs and the invasion of water into producing formations.

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

Oil and natural gas are commodities whose prices are determined based on world demand, supply and other factors, all of which are beyond our control. World prices for oil and natural gas have fluctuated widely in recent years. The average price for WTI per barrel was $66 in 2006, $72 in 2007, $100 in 2008, $62 in 2009, $79 in 2010, $95 in 2011 and $94 in 2012, demonstrating the inherent volatility in the market. Average Brent oil prices for the year ended December 31, 2012, were $111.67 per bbl. Given the current economic environment and unstable conditions in the Middle East, North Africa, the United States and Europe, the oil price environment is increasingly unpredictable and unstable. We expect that prices will fluctuate in the future. Price fluctuations will have a significant impact upon our revenue, the return from our oil and gas reserves and on our financial condition generally. Price fluctuations for oil and natural gas commodities may also impact the investment market for companies engaged in the oil and gas industry. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contract with purchasers with prescribed deductions for transportation and quality differentials. These differentials can change over time and have a detrimental impact on realized prices. Future decreases in the prices of oil and natural gas may have a material adverse effect on our financial condition, the future results of our operations and quantities of reserves recoverable on an economic basis.

In addition, oil and natural gas prices in Argentina are effectively regulated and during 2009, 2010, 2011 and 2012, were substantially lower than those received in North America. Oil prices in Colombia are related to international market prices, but adjustments that are defined by contract with Ecopetrol, the purchaser of most of the oil that we produce in Colombia, may cause realized prices to be lower or higher than those received in North America. Oil prices in Brazil are defined by contract with the refinery and may be lower or higher than those received in North America.

Decommissioning Costs Are Unknown and May be Substantial; Unplanned Costs Could Divert Resources from Other Projects.
We are responsible for costs associated with abandoning and reclaiming some of the wells, facilities and pipelines which we use for production of oil and gas reserves. Abandonment and reclamation of these facilities and the costs associated therewith is often referred to as "decommissioning." We have determined that we require a reserve account for these potential costs in respect of our current properties and facilities at this time, and have booked such reserve on our financial statements. If decommissioning is required before economic depletion of our properties or if our estimates of the costs of decommissioning exceed the value of the reserves remaining at any particular time to cover such decommissioning costs, we may have to draw on funds from other sources to satisfy such costs. The use of other funds to satisfy decommissioning costs could impair our ability to focus capital investment in other areas of our business.

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

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

Environmental Risks May Adversely Affect Our Business.
All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of international conventions and federal, provincial and municipal laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner we expect may result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to foreign governments and third parties and may require us to incur costs to remedy such discharge. The application of environmental laws to our business may cause us to curtail our production or increase the costs of our production, development or exploration activities.

Our Insurance May Be Inadequate to Cover Liabilities We May Incur.
Our involvement in the exploration for and development of oil and natural gas properties may result in our becoming subject to liability for pollution, blowouts, property damage, personal injury or other hazards. Although we have insurance in accordance with industry standards to address such risks, such insurance has limitations on liability that may not be sufficient to cover the full extent of such liabilities. In addition, such risks may not in all circumstances be insurable or, in certain circumstances, we may choose not to obtain insurance to protect against specific risks due to the

high premiums associated with such insurance or for other reasons. The payment of such uninsured liabilities would reduce the funds available to us. If we suffer a significant event or occurrence that is not fully insured, or if the insurer of such event is not solvent, we could be required to divert funds from capital investment or other uses towards covering our liability for such events.

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

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

If our property rights are reduced, whether by governmental action or third party challenges, our ability to conduct our exploration, development and production may be impaired.

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

Risks Related to Our Common Stock

The Market Price of Our Common Stock May Be Highly Volatile and Subject to Wide Fluctuations.
The market price of shares of our Common Stock may be highly volatile and could be subject to wide fluctuations in response to a number of factors that are beyond our control, including but not limited to:

- dilution caused by our issuance of additional shares of Common Stock and other forms of equity securities, which we expect to make in connection with acquisitions of other companies or assets;
- announcements of new acquisitions, reserve discoveries or other business initiatives by our competitors;
- fluctuations in revenue from our oil and natural gas business;
- changes in the market and/or WTI or Brent price for oil and natural gas commodities and/or in the capital markets generally, or under our credit agreement;
- changes in the demand for oil and natural gas, including changes resulting from the introduction or expansion of alternative fuels;
- changes in the social, political and/or legal climate in the regions in which we will operate;
- changes in the valuation of similarly situated companies, both in our industry and in other industries;
- changes in analysts' estimates affecting us, our competitors and/or our industry;
- changes in the accounting methods used in or otherwise affecting our industry;
- announcements of technological innovations or new products available to the oil and natural gas industry;
- announcements by relevant governments pertaining to incentives for alternative energy development programs;
- fluctuations in interest rates, exchange rates and the availability of capital in the capital markets; and
- significant sales of shares of our Common Stock, including sales by future investors in future offerings we expect to make to raise additional capital.

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

- quarterly variations in our revenues and operating expenses; and
- additions and departures of key personnel.

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

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

Directors and Executive Officers

Set forth below is information regarding our directors and executive officers as of February 20, 2013.

Name	Position
Jeffrey Scott	Chairman
Gerry Macey	Director
Verne Johnson	Director
Nick Kirton	Director
Scott Price	Director
Ray Antony	Director
Dana Coffield	President and Chief Executive Officer; Director
James Rozon	Chief Financial Officer
Shane O'Leary	Chief Operating Officer
David Hardy	General Counsel, Vice-President Legal, and Secretary
Rafael Orunesu	President and General Manager Gran Tierra Energy Argentina
Duncan Nightingale	President and General Manager Gran Tierra Energy Colombia
Julio Cesar Moreira	President and General Manager Gran Tierra Energy Brazil
Carlos Monges	President and General Manager Gran Tierra Energy Peru

Jeffrey Scott, Chairman. Mr. Scott has served as Chairman of our Board of Directors since January 2005. Since 2001, Mr. Scott has served as President of Postell Energy Co. Ltd., a privately held oil and gas producing company. He has extensive oil and gas management experience, beginning as a production manager of Postell Energy Co. Ltd in 1985 advancing to President in 2001. Mr. Scott is also currently a Director of Essential Energy Services Trust, Petromanas Energy Inc. and Gallic Energy Ltd. Mr. Scott will not stand for re-election of Essential Energy Services and his term will end in May 2011. He was previously a director of Suroco Energy, Inc., VGS Seismic Canada Inc., High Plains Energy Inc., Saxon Energy Services Inc. and Galena Capital Corp., all of which are publicly-traded companies. Mr. Scott holds a Bachelor of Arts degree from the University of Calgary, and a Masters of Business Administration from California Coast University. The Nominating and Corporate Governance Committee recommended Mr. Scott for re-election because of his demonstrated leadership value and experience which includes 27 years of experience in the oil and gas industry, financial oversight responsibilities and public company reporting requirements.

Gerry Macey, Director. Gerry Macey has over 38 years of experience in the petroleum industry including exploration and development expertise in basins around the world. He received a Bachelors degree in Geotechnical Science from Concordia University and went on to study at Carleton University to receive his Masters of Science in Geology. Mr. Macey's professional career started as a Geologist with Gulf Canada Resources and Gulf Oil Corporation, U.K., which was followed by BP Resources Canada, Pan Canadian Petroleum and ultimately Encana Corporation, where he served as President, International New Ventures Exploration Division and Executive Vice President. He has sat on numerous domestic and international Boards, including more recently Addax Petroleum Corporation and Verenex Energy Corporation. He is currently on the Boards of Andora Energy and Pan Orient Energy Corporation.

Mr. Macey is currently a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, Canadian Society of Petroleum Geologists and the American Association of Petroleum Geologists. He was awarded the Stanley Slipper Gold Medal, the most prestigious award of the Canadian Society of Petroleum Geologists, for outstanding contribution to petroleum exploration in Canada, in 2005, and the Minerals Management Service Corporate Leadership Award, for exemplary leadership of the McCovey exploration project in the Beaufort Sea Outer Continental Shelf, in 2003.

Verne Johnson, Director. Verne has an extensive career in the energy industry after receiving a Bachelor of Science Degree in Mechanical Engineering from the University of Manitoba. Mr. Johnson began his career with Imperial Oil and EXXON, Verne was CEO & President of ELAN Energy, President of Paragon Petroleum, and Senior Vice President of Enerplus Resources Group. Verne is currently a director of a number of independent oil companies in Canada including Petromanas Energy, Statoil Canada, Verersen (formerly Fort Chicago Energy), as well as a number of private companies.

Nick Kirton, FCA, ICD.D, Director. Nick is a Chartered Accountant and retired in 2004 after a thirty-eight year career with KPMG. He currently sits on the boards of three other public companies. He is also a member of the Board of Governors of the University of Calgary and the Board of Directors of the Canadian Investor Protection Fund and is a member of the Education and Qualifications Committee of the Canadian Institute of Chartered Accountants. Nick is Chairman of the Audit Committee for Gran Tierra Energy.

Scott Price, DIrector. Scott has 25 years of diverse global oil and gas experience in North and South America, Europe, Africa, Middle East and the former Soviet Union. Most recently he was the President and CEO of Solana Resources Limited prior to its combination with Gran Tierra in November, 2008. He has been a founder, director, and /or officer of a number in internationally focused public and private companies including Aventura Energy Inc., and Ocelot International Inc. Mr. Price holds a Bachelor of Science degree in Chemical Engineering and a Masters of Business Administration both from the University of Calgary.

Ray Antony, B.Comm, C.A., Director. Ray has been a Chartered Accountant for more than thirty years. An independent business man since September, 2006 Ray was previously the President of Breakside Energy Ltd., a private oil and gas exploration and production company since January 2004. Prior, Ray was President of Resolution Resources Ltd., a public oil and gas exploration and production company since October 2001. Mr. Antony has obtained significant financial experience and exposure to accounting and financial issues as a director and audit committee member of a number of public companies with international operations in Argentina, Algeria, Papua New Guinea and Peru.

Dana Coffield, President, Chief Executive Officer and Director. Before joining Gran Tierra as President, Chief Executive Officer and a Director in May, 2005, Mr. Coffield led the Middle East Business Unit for Encana Corporation, at the time North America's largest independent oil and gas company, from 2003 to 2005. His responsibilities included business development, exploration operations, commercial evaluations, government and partner relations, planning and budgeting, environment/health/safety, security and management of several overseas operating offices. From 1998 through 2003, he was New Ventures Manager for Encana's predecessor — Alberta Energy Company — where he expanded exploration operations into five new countries on three continents. Mr. Coffield was previously with ARCO International for ten years, where he participated in exploration and production operations in North Africa, Southeast Asia and Alaska. He began his career as a mud-logger in the Texas Gulf Coast and later as a Research Assistant with the Earth Sciences and Resources Institute where he conducted geoscience research in North Africa, the Middle East and Latin America. Mr. Coffield graduated from the University of South Carolina with a Masters of Science (MSc) degree and a doctorate (PhD) in Geology, based on research conducted in the Oman Mountains in Arabia and Gulf of Suez in Egypt, respectively. He has a Bachelor of Science degree in Geological Engineering from the Colorado School of Mines. Mr. Coffield is a member of the AAPG and the CSPG, and is a Fellow of the Explorers Club.

James Rozon, Chief Financial Officer. On May 2, 2012, James Rozon was promoted from acting Chief Financial Officer to Chief Financial Officer. Mr. Rozon had been serving as acting Chief Financial Officer since December 9, 2011. Mr. Rozon served as Gran Tierra's Corporate Controller from October 1, 2007 to December 9, 2011. He has previous experience in accounting, finance and administration in the petroleum and technology industries in Canada. During his career, his responsibilities have included management of finance related activities of Canadian and American oil and gas exploration and production companies operating in Canada and the United States and a software development company operating in Canada, the United States, China and Sweden. He was Controller of Sound Energy Trust, a publicly listed Canadian oil and gas trust from July 2006 to September 2007, at which time it was sold. From October 2002 to June 2006, and previously from July 1995 to February 1998, he was the Corporate Controller of Zi Corporation, a Canadian software development company publicly listed in both Canada and the United States of America. From June 2000 to September 2002, he was the Controller for Energy Exploration Technologies, an American publicly listed oil and gas exploration company operating in Canada and the United States. From April 1998 to May 2000, he was the Manager, Financial Reporting of Summit Resources Limited, a publicly listed Canadian oil and gas exploration and development company with operations in Canada and the United States of America. From June 1990 to June 1995, Mr. Rozon worked in public practice for five years for Deloitte & Touche LLP including one year as an audit manager in the Oil and Gas group in the Calgary, Alberta office. Mr. Rozon holds a Bachelor of Commerce degree from the University of Saskatchewan and is a member of the Institute of Chartered Accountants of Alberta and the Institute of Chartered Accountants of Saskatchewan.

Shane P. O'Leary, Chief Operating Officer. Mr. O'Leary joined the company as Chief Operating Officer effective March 2, 2009. Mr. O'Leary's regional experience includes South America, North Africa, the Middle East, the former Soviet Union, and North America. Prior to joining Gran Tierra, Mr. O'Leary was President and Chief Executive Officer of First Calgary Petroleums Ltd., an oil and natural gas company actively engaged in exploration and development activities in Algeria. In this role, he was responsible for all operating and corporate activities involved in a $2 billion development program for the exploitation of a resource base exceeding three trillion cubic feet of natural gas equivalent in the Sahara desert, Algeria. Mr. O'Leary led initiatives to explore strategic options which resulted in the sale of the company to ENI SpA for over $1 billion. From 2002 to 2006, Mr. O'Leary worked for Encana Corporation where his positions included Vice President of Development Planning and Engineering, International New Ventures, as well as Vice President Brazil Business Unit. In these roles Mr. O'Leary was responsible for all engineering and development planning for new discoveries of the International New Ventures Division and later leading the Brazil team involved in appraising an offshore discovery subsequently divested for $360 million.

Mr. O'Leary was also architect of a technology cooperation agreement with Petrobras involving numerous partnerships in offshore acreage in exchange for assistance to Petrobras in applying Canadian Heavy Oil production technology in Brazil. From 1985 to 2002 he worked for the Amoco Production Company/BP Exploration where he occupied numerous senior finance, planning, and business development positions with assignments in Canada, U.S.A., Azerbaijan and Egypt, culminating in his role as Business Development Manager for BP Alaska Gas. Early in his career Mr. O'Leary worked as a Corporate Banking Officer for Bank of Montreal's

Petroleum group in Calgary, a Reservoir Engineer for Dome Petroleum, and as a Senior Field Engineer for Schlumberger Overseas, S.A. in Kuwait. Mr. O'Leary earned his Bachelor of Science degree in chemical engineering from Queen's University in Kingston, Ontario and his Masters in Business Administration from the University of Western Ontario in London, Ontario. He is a member of the Canadian National Committee of the World Petroleum Council and The Association of Professional Engineers, Geologists, and Geophysicists of Alberta (P. Eng).

David Hardy, General Counsel, Vice President Legal and Secretary. Mr. Hardy joined Gran Tierra as General Counsel, Vice President Legal and Secretary on March 1, 2010. He has more than 20 years' experience in the legal profession. Before joining Gran Tierra, he worked for Encana Corporation from 2000 through 2009 where he held various positions, including: Vice President Divisional Legal Services, Integrated Oil and Canadian Plains Divisions; Vice President Regulatory Services, Corporate Relations Division; and Associate General Counsel, Offshore and International Division. For four of his eight years in the Offshore and International Division of Encana, Mr. Hardy led the Legal and Commercial Negotiations Group, where he was responsible for providing strategic legal, commercial and negotiation advice and support to the offshore and international business units. This included dealing with new venture activities and operational, joint venture and host government issues relating to projects in various countries, including Australia, Brazil, Chad, Libya, Oman, Qatar and Yemen. Prior to joining Encana, Mr. Hardy spent over 10 years in private practice and was a partner in a law firm in Calgary, Alberta. He holds a Juris Doctor Degree from the University of Calgary (converted from an LL.B Degree in 2011) and is a member of the Law Society of Alberta and the Association of International Petroleum Negotiators.

Rafael Orunesu, President and General Manager Gran Tierra Argentina. Mr. Orunesu joined Gran Tierra in March 2005. He brings a mix of operations management, project evaluation, production geology, reservoir and production engineering skills to Gran Tierra, with a South American focus. Prior to joining Gran Tierra he was Engineering Manager for Pluspetrol Peru, from 1997 through 2004, responsible for planning and development operations in the Peruvian North jungle. He participated in numerous evaluation and asset purchase and sale transactions covering Latin America and North Africa, discovering 200 MMbbl of oil over a five-year period. Mr. Orunesu was previously with Pluspetrol Argentina from 1990 to 1996 where he managed the technical/economic evaluation of several oil fields. He began his career with YPF, initially as a geologist in the Austral Basin of Argentina and eventually as Chief of Exploitation Geology and Engineering for the Catriel Field in the Neuquén Basin, where he was responsible for drilling programs, workovers and secondary recovery projects.

Mr. Orunesu has a postgraduate degree in Reservoir Engineering and Exploitation Geology from Universidad Nacional de Buenos Aires and a degree in Geology from Universidad Nacional de la Plata, Argentina.

Duncan Nightingale, President and General Manager Gran Tierra Energy Colombia. Mr. Nightingale joined Gran Tierra in September 2009, where he served in our Calgary, Canada office as our Vice President of Exploration from September 2009 to January 2011. He served in our Bogotá, Colombia office as our Senior Manager Project Planning and Exploration from January 2011 until August 2011, and was promoted to President of Gran Tierra Energy Colombia in August 2011. Prior to joining Gran Tierra, Mr. Nightingale was Senior Vice President, Exploration & Production, at Artumas Group Inc., a Canadian oil and gas company focusing on exploration and development of hydrocarbon reserves in Tanzania and Mozambique, where he was responsible for Artumas Group's exploration and production operations in Mozambique and Tanzania and management of its gas processing plant and power generation facility in Tanzania. Prior to Artumas Group, Mr. Nightingale was General Manager, Exploration & Production, with Dana Gas PJSC, a leading private sector natural gas company in the Middle East, where Mr. Nightingale was responsible for all of Dana Gas's exploration and production operations, and was responsible for a multi-million dollar exploration and development program in Kurdistan. Prior to Dana Gas, Mr. Nightingale was with Encana Corporation's International Division from May 2002 until March 2007. From June 2002 until September 2003, he was the Country Manager in Qatar, responsible for managing Encana's activities in Qatar, including the execution of exploration programs and new venture activity. From October 2003 until June 2006, he had similar responsibilities in the Sultanate of Oman, where he served as Encana's Country Manager. Mr. Nightingale has a total of 30 years of corporate head office and resident in-country international operating experience, spanning all aspects of managing exploration programs, development and production operations, new business ventures, portfolio management and strategic planning. Mr. Nightingale graduated from the University of Nottingham in the U.K. with a Bachelor of Science degree with honors in Geology.

Julio Cesar Moreira, President and General Manager Gran Tierra Energy Brasil. Mr. Moreira joined our company as President, Gran Tierra Brazil in September 2009. Mr. Moreira has over 25 years of experience working for international companies in Brazil and USA in senior business development and management positions. Most recently, he was Managing Director for IBV Brasil Petroleo Ltda from September 2008 to August 2009 where he managed a portfolio of assets including 10 Exploration Deep Water Blocks located in Sergipe-Alagoas, Espirito Santo, Potiguar and Campos Basins, all in Brazil, and Brazil Country Manager for Encana Corporation from December 2001 to September 2008, where he was instrumental in capturing assets which were later sold for a combined value of over $500 million. Before Encana Corporation, Mr. Moreira was Brazil New Ventures & Business Development Vice President for Unocal Corporation where he successfully completed a $180 million corporate transaction to acquire a Natural Gas / Condensate field in Northeast Brazil and captured Deep Water Exploration assets offshore Brazil. Mr. Moreira holds an Information Technology degree from Universidade Federal Fluminense in Rio de Janeiro, and a post-graduate degree in Marketing from Rio Catholic University. In addition, he attended the Executive MBA Program at UFRJ/ Coppead (Brazil), the Executive Management programs in Oil and Gas at Thunderbird (USA) and the Ivey Executive Program at the University of Western Ontario (Canada).

Carlos Monges, President and General Manager Gran Tierra Energy Peru. Mr. Monges has over 30 years of experience in the oil industry. He joined our company upon its acquisition of Petrolifera Petroleum Limited ("Petrolifera") in March 2011. He was Petrolifera's country manager in Peru since 2005, with responsibility for management and exploratory operations in three onshore blocks. He was the senior geologist on the team that performed for PeruPetro S.A. ("PeruPetro") a geological and geophysical assessment of Peru's hydrocarbon basins which was sponsored by the Canadian and Peruvian governments. Prior to that, Mr. Monges was the Operations Manager for Energy Development, Anadarko Petroleum and then BPZ Energy with respect to various offshore and onshore blocks in Peru. He began his career in the industry working as a field development geologist and a well-site and production geologist in Talara Basin for Petróleos del Perú S.A. and Occidental Petroleum and also worked as a mud engineer in drilling operations in Venezuela and Argentina. Mr. Monges received his Bachelor of Science Degree in Geological Engineering from Universidad Nacional Mayor de San Marcos, Lima in 1978, performed studies on exploration techniques at Robertson Research Center in United Kingdom in 1990, and completed certificate studies on oil industry management at the IHRDC program in Boston, USA in 1997. He is a current member and past director of the Peruvian Geological Society.

Market for Common Equity and Related Stockholder Matters

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

As of February 20, 2013, there were approximately: 38 holders of record of shares of our Common Stock and 268,621,445 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately six holders of record of 6,223,810 exchangeable shares which may be exchanged on a 1-for-1 basis into shares of our Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing nine holders of record of 7,058,678 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into shares of our Common Stock.

For the quarters indicated from January 1, 2011, through the end of the fourth quarter of 2012, the following table shows the high and low closing sale prices per share of our Common Stock as reported on the NYSE MKT.

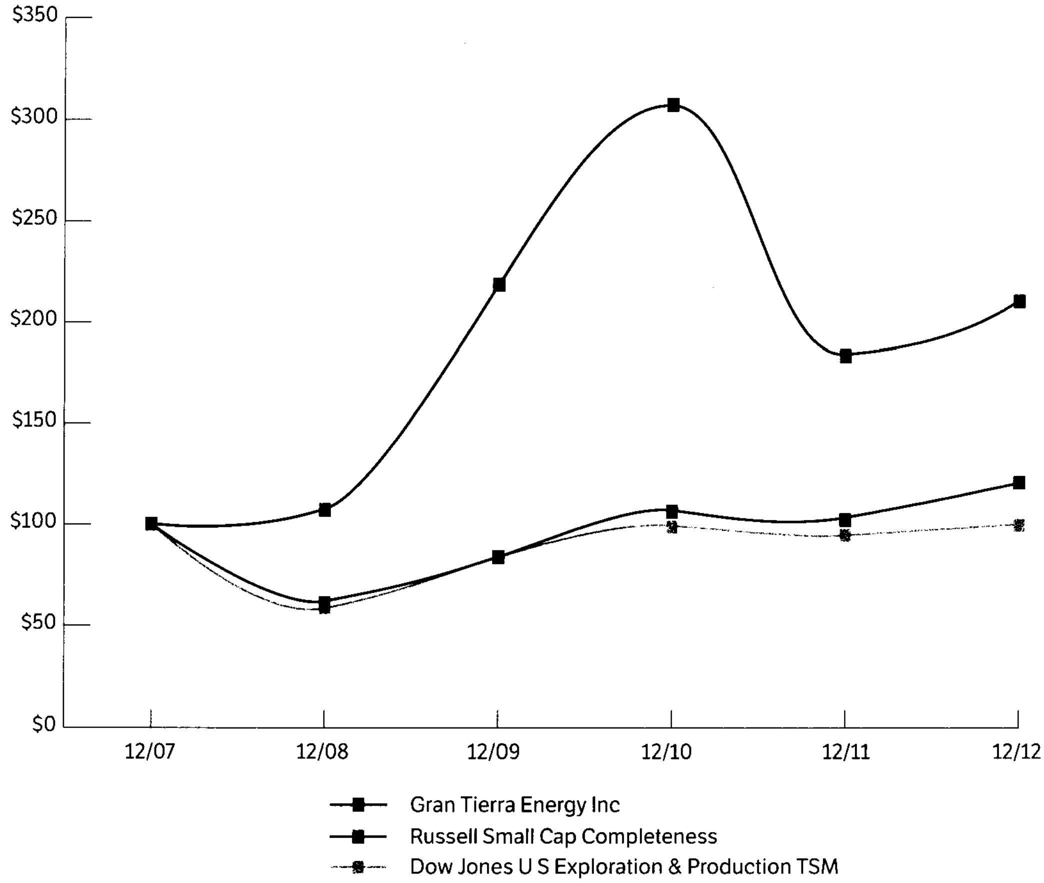
	High	Low
Fourth Quarter 2012	$ 5.93	$ 4.87
Third Quarter 2012	$ 5.51	$ 4.17
Second Quarter 2012	$ 6.64	$ 4.44
First Quarter 2012	$ 6.29	$ 4.73
Fourth Quarter 2011	$ 6.47	$ 4.42
Third Quarter 2011	$ 7.20	$ 4.68
Second Quarter 2011	$ 8.17	$ 6.10
First Quarter 2011	$ 9.54	$ 7.75

Dividend Policy

We have never declared or paid dividends on the shares of Common Stock and we intend to retain future earnings, if any, to support the development of the business and therefore do not anticipate paying cash dividends for the foreseeable future. Payment of future dividends, if any, will be at the discretion of our board of directors after taking into account various factors, including current financial condition, operating results and current and anticipated cash needs. Under the terms of our credit facility we cannot pay any dividends to our shareholders if we are in default under the facility, and if we are not in default then are required to obtain bank approval for any dividend payments made by us exceeding $2 million in any fiscal year.

Performance Graph

Comparison of 5 Year Cumulative Total Return*
Among Gran Tierra Energy Inc, the Russell Small Cap Completeness Index,
and the Dow Jones US Exploration & Production TSM Index



*$100 invested on 12/31/07 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31

	12/07	12/08	12/09	12/10	12/11	12/12
Gran Tierra Energy Inc	100	106.87	218.7	307.25	183.21	210.31
Russell Small Cap Completeness	100	61.02	84.03	106.4	102.23	120.68
Dow Jones US Exploration & Production TSM	100	58.97	83.46	98.81	94.76	99.66

Selected Financial Data

(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

Statement of Operations Data	**Year Ended December 31, 2012**	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Oil and natural gas sales	**$ 583,109**	$ 596,191	$ 373,286	$ 262,629	$ 112,805
Interest income	**2,078**	1,216	1,174	1,087	1,224
	585,187	597,407	374,460	263,716	114,029
Operating expenses	**124,903**	86,497	59,446	40,784	19,218
DD&A expenses	**182,037**	231,235	163,573	135,863	25,737
G&A expenses	**58,882**	60,389	40,241	28,787	18,593
Other gain	**(9,336)**	—	—	—	—
Equity tax	**—**	8,271	—	—	—
Financial instruments gain (loss)	**—**	(1,522)	(44)	190	(193)
Gain on acquisition	**—**	(21,699)	—	—	—
Foreign exchange loss (gain)	**31,338**	(11)	16,838	19,797	6,235
	387,824	363,160	280,054	225,421	69,590
Income before income taxes	**197,363**	234,247	94,406	38,295	44,439
Income tax expense	**(97,704)**	(107,330)	(57,234)	(24,354)	(20,944)
Net income	**$ 99,659**	$ 126,917	$ 37,172	$ 13,941	$ 23,495
Net income per common share – basic	**$ 0.35**	$ 0.46	$ 0.15	$ 0.06	$ 0.19
Net income per common share – diluted	**$ 0.35**	$ 0.45	$ 0.14	$ 0.05	$ 0.16

Balance Sheet Data	**Year Ended December 31, 2012**	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008
Cash and cash equivalents	**$ 212,624**	$ 351,685	$ 355,428	$ 270,786	$ 176,754
Working capital (including cash)	**222,468**	213,100	265,835	215,161	132,807
Oil and gas properties	**1,196,661**	1,036,850	721,157	709,568	765,050
Deferred tax asset – long term	**1,401**	4,747	—	7,218	10,131
Total assets	**1,732,875**	1,626,780	1,249,254	1,143,808	1,072,625
Deferred tax liability – long term	**225,195**	186,799	204,570	216,625	213,093
Total long-term liabilities	**250,059**	207,633	210,075	221,786	218,461
Shareholders' equity	**$ 1,291,431**	$ 1,174,318	$ 886,866	$ 816,426	$ 791,926

In November 2008, we acquired Solana Resources Limited ("Solana") for $671.8 million through the issuance to Solana stockholders of either shares of our Common Stock or shares of common stock of a subsidiary of Gran Tierra. On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera Petroleum Limited ("Petrolifera") pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru. See "Business Combination" in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further details.

Management's Discussion and Analysis of Financial Condition and Results of Operations

This report, and in particular this Management's Discussion and Analysis of Financial Condition and Results of Operations, contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Please see the cautionary language at the very beginning of this Annual Report regarding the identification of and risks relating to forward-looking statements, as well as the section entitled "Risk Factors" in this Annual Report.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements and Supplementary Data" as set out in this Annual Report.

Overview

We are an independent international energy company incorporated in the United States and engaged in oil and natural gas acquisition, exploration, development and production. Our operations are carried out in South America in Colombia, Argentina, Peru, and Brazil, and we are headquartered in Calgary, Alberta, Canada. For the year ended December 31, 2012, 84% (year ended December 31, 2011 – 91%; year ended December 31, 2010 – 96%) of our revenue and other income was generated in Colombia.

As of December 31, 2012, we had estimated proved reserves NAR of 40.6 MMBOE, comprising 95% oil and 5% natural gas, of which 72% were proved developed reserves. Our primary source of liquidity is cash generated from our operations.

The price of oil is a critical factor to our business and the price of oil has historically been volatile. Future volatility could be detrimental to our financial performance. During 2012, the average price realized for our oil was $97.31 per barrel (2011 – $96.60; 2010 – $71.19).

Business Strategy

Our plan is to continue to build an international oil and gas company through acquisition and exploitation of under-developed prospective oil and gas assets, and to develop these assets with exploration and development drilling to grow commercial reserves and production. Our initial focus is in select countries in South America, currently Colombia, Argentina, Peru, and Brazil; we will consider other regions for future growth should those regions make strategic and commercial sense in creating additional value.

We have applied a two-stage approach to growth, initially establishing a base of production, development and exploration assets by selective acquisitions, and secondly achieving additional reserve and production growth through drilling. We intend to duplicate this business model in other areas as opportunities arise. We pursue opportunities in countries with proven petroleum systems; attractive royalty, taxation and other fiscal terms; and stable legal systems.

Highlights

	Year Ended December 31,				
	2012	% Change	2011	% Change	2010
Estimated Proved Oil and Gas Reserves, NAR, at December 31 (MMBOE) (1)	**40.6**	19	34.0	43	23.8
Production (BOEPD) (1)	**16,897**	(3)	17,408	20	14,448
Prices Realized – per BOE	**$ 94.29**	—	$ 93.83	33	$ 70.79
Revenue and Other Income ($000s)	**$ 585,187**	(2)	$ 597,407	60	$ 374,460
Net Income ($000s)	**$ 99,659**	(21)	$ 126,917	241	$ 37,172
Net Income Per Share – Basic	**$ 0.35**	(24)	$ 0.46	207	$ 0.15
Net Income Per Share – Diluted	**$ 0.35**	(22)	$ 0.45	221	$ 0.14
Funds Flow From Operations ($000s) (2)	**$ 323,756**	1	$ 319,046	57	$ 203,136
Capital Expenditures ($000s)	**$ 313,176**	(4)	$ 327,647	85	$ 177,039

	As at December 31,				
	2012	% Change	2011	% Change	2010
Cash & Cash Equivalents ($000s)	**$ 212,624**	(40)	$ 351,685	(1)	$ 355,428
Working Capital (including cash & cash equivalents) ($000s)	**$ 222,468**	4	$ 213,100	(20)	$ 265,835
Property, Plant & Equipment ($000s)	**$ 1,205,426**	15	$ 1,044,842	44	$ 727,024

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

(2) Funds flow from 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 the 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 operations, as presented, is net income adjusted for depletion, depreciation, accretion and impairment ("DD&A") expenses, deferred taxes, stock-based compensation, unrealized gain on financial instruments, unrealized foreign exchange loss or gain, settlement of asset retirement obligation, other gains, equity tax and gain on acquisition. A reconciliation from net income to funds flow from operations is as follows:

	Year Ended December 31,		
Funds Flow From Operations – Non-GAAP Measure ($000s)	**2012**	2011	2010
Net income	**$ 99,659**	$ 126,917	$ 37,172
Adjustments to reconcile net income to funds flow from operations			
DD&A expenses	**182,037**	231,235	163,573
Deferred taxes	**26,274**	(28,685)	(19,679)
Stock-based compensation	**12,006**	12,767)	8,025
Unrealized gain on financial instruments	**—**	(1,354)	(44)
Unrealized foreign exchange loss (gain)	**17,054**	(2,232)	14,375
Settlement of asset retirement obligation	**(404)**	(345)	(286)
Other gain	**(9,336)**	—	—
Equity tax	**(3,534)**	2,442	—
Gain on acquisition	**—**	(21,699)	—
Funds flow from operations	**$ 323,756**	$ 319,046	$ 203,136

- For the year ended December 31, 2012, oil and gas production, NAR and adjusted for inventory changes, decreased by 3% to 16,897 BOEPD compared with 2011. Production, NAR and adjusted for inventory changes, in 2012 was 66% from the Chaza Block in Colombia and 12% and 6% from the Puesto Morales and Surubi Blocks in Argentina, respectively. Production during the year ended December 31, 2012, was impacted by an increase in oil inventory in the Ecopetrol-operated Trans-Andean oil pipeline (the "OTA pipeline") in Colombia and associated Ecopetrol owned facilities in the Putumayo Basin as a result of a change in the sales point from the entry into the OTA pipeline to the Port of Tumaco for volumes sold to Ecopetrol; oil delivery restrictions due to OTA pipeline disruptions; and increased oil inventory due to increased sales to a customer with a protracted sales cycle whereby the transfer of ownership occurs upon export, partially offset by production from new producing wells in Colombia and Argentina.
- Estimated proved oil and NGL reserves, NAR, as of December 31, 2012, were 38.5 MMbbl, a 25% increase from the estimated proved reserves as at December 31, 2011. The increase was due primarily to positive technical adjustments for the Costayaco field due to reservoir performance, successful appraisal drilling on the Moqueta field and exploration success with the Ramiriqui-1 well in Colombia. Reserves were also added through development drilling on the Tiê field in the Recôncavo Basin, Brazil and the Proa-2 development well on the Surubi Block in Argentina. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2012, were 14.8 MMbbl and 21.5 MMbbl, respectively.

- Estimated proved gas reserves, NAR, as of December 31, 2012, were 12.8 Bcf compared with 18.3 Bcf as at December 31, 2011. At December 31, 2012, 61% of proved gas reserves were in the Sierra Nevada Block in Colombia and 26% were in the Puesto Morales Block in Argentina. Estimated proved gas reserves, NAR, in the Sierra Nevada Block decreased by 6.0 Bcf during the year ended December 31, 2012, due to technical revisions. Proved gas reserves in the Puesto Morales Block were consistent with the prior year end as new gas reserves were created to replace 2012 production. Estimated probable and possible gas reserves, NAR, as of December 31, 2012, were 5.1 Bcf and 51.7 Bcf, respectively, due to technical revisions in the Sierra Nevada Block.
- For the year ended December 31, 2012, revenue and other income decreased by 2% to $585.2 million compared with $597.4 million in 2011. The average price realized per BOE of $94.29 was consistent with 2011 and was impacted by the settlement of a third party royalty dispute in Colombia which reduced the average realized price by $1.76 per BOE.
- Net income decreased by 21% to $99.7 million, or $0.35 per share basic and diluted, for the year ended December 31, 2012, compared with $126.9 million, or $0.46 per share basic and $0.45 per share diluted, in 2011. In 2012, decreased DD&A, G&A and income tax expenses, the realization of a value added tax recovery upon a corporate reorganization in Colombia and the absence of the Colombian equity tax expense were more than offset by decreased oil and natural gas sales, increased operating expenses and foreign exchange losses, and the absence of the 2011 gain on acquisition of Petrolifera Petroleum Limited ("Petrolifera").
- For the year ended December 31, 2012, funds flow from operations increased by 1% from $319.0 million to $323.8 million primarily due to lower income tax expenses being partially offset by increased operating expenses and realized foreign exchange losses.
- Cash and cash equivalents were $212.6 million at December 31, 2012, compared with $351.7 million at December 31, 2011. The change in cash and cash equivalents during 2012 was primarily the result of funds flow from operations of $323.8 million, a $11.9 million decrease in restricted cash and proceeds from issuance of common stock of $4.3 million being more than offset by capital expenditures of $276.1 million, an increase in net assets and liabilities from operating activities of $167.4 million and cash paid for an acquisition in Brazil of $35.5 million.
- Working capital (including cash and cash equivalents) was $222.5 million at December 31, 2012, a $9.4 million increase from December 31, 2011. The increase was primarily a result of the following: a $50.5 million increase in accounts receivable due to a change in the timing of collection of Ecopetrol receivables, new customers in Colombia and increased oil and gas sales in Argentina; a $26.4 million increase in inventory; an $18.4 million increase in taxes receivable due to value added tax and income tax recoveries in Colombia generated upon completion of a corporate reorganization; a $73.1 million decrease in taxes payable due to utilization of tax losses and tax deductions resulting from the same corporate reorganization, and lower taxable income in Colombia; partially offset by a $139.1 million decrease in cash and cash equivalents and a $19.7 million increase in accounts payable and accrued liabilities due to increased capital activity in Peru and Brazil immediately prior to year end.
- Property, plant and equipment at December 31, 2012, was $1.2 billion, an increase of $160.6 million from December 31, 2011, as a result of $313.2 million of capital expenditures (including changes in non-cash working capital), the acquisition of the remaining 30% working interest in certain blocks in Brazil, partially offset by $189.1 million of depletion, depreciation and impairment expenses.
- Our capital expenditures for the year ended December 31, 2012, were $313.2 million compared with $327.6 million for the year ended December 31, 2011. In 2012, capital expenditures included drilling of $218.1 million, acquisitions of $12.5 million, geological and geophysical ("G&G") expenditures of $48.0 million, facilities of $17.9 million and other expenditures of $16.7 million. Additionally, we spent $36.6 million on the acquisition of the remaining 30% working interest in our properties in Brazil.

Estimated Oil and Gas Reserves

As at December 31, 2012, the estimated proved oil and gas reserves, NAR, were 40.6 MMBOE compared with 34.0 MMBOE as at December 31, 2011 and 23.8 MMBOE as at December 31, 2010.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2012, were 38.5 MMbbl, a 25% increase from the estimated proved oil and NGL reserves as at December 31, 2011. The increase was due primarily to positive technical adjustments for the Costayaco field due to reservoir performance, successful appraisal drilling on the Moqueta field and exploration success with the Ramiriqui-1 well in Colombia. Reserves were also added through development drilling on the Tiê field in the Recôncavo Basin, Brazil and the Proa-2 development well on the Surubi Block in Argentina. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2012 were 14.8 MMbbl and 21.5 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2012, were 12.8 Bcf compared with 18.3 Bcf at December 31, 2011. At December 31, 2012, 61% of proved gas reserves were in the Sierra Nevada Block and 26% were in the Puesto Morales Block. Estimated proved gas reserves, NAR, in the Sierra Nevada Block decreased by 6.0 Bcf during the year ended December 31, 2012 due to technical revisions. Proved gas reserves in the Puesto Morales Block were consistent with the prior year end as new gas reserves were created to replace 2012 production. Estimated probable and possible gas reserves, NAR, as of December 31, 2012 were 5.1 Bcf and 51.7 Bcf, respectively, due to technical revisions in the Sierra Nevada Block.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2011, were 30.9 MMbbl, a 31% increase from the estimated proved reserves as at December 31, 2010. The increase was due to the acquisition of Petrolifera which had reserves in Argentina and Colombia, positive technical revisions to Costayaco reserves (based on reservoir performance), the drilling of additional appraisal wells in the Moqueta field and the acquisition of the 70% working interest ("WI") in Block 155 in Brazil, which more than offset 2011 production of oil and NGLs. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2011 were 10.5 MMbbl and 17.6 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2011, were 18.3 Bcf compared with 1.2 Bcf at December 31, 2010. Estimated probable and possible gas reserves, NAR, as of December 31, 2011 were 25.7 Bcf and 116.5 Bcf, respectively.

Business Environment Outlook

Our revenues have been significantly affected by pipeline 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 demand growth.

We believe that our current operations and 2013 capital expenditure program can be funded from cash flow from existing operations, cash on hand and potential periodic draws from our revolving credit facility. Should our operating cash flow decline further due to unforeseen events, including additional pipeline delivery restrictions in Colombia or a downturn in oil and gas prices, we would examine measures such as further capital expenditure program reductions, issuance of debt, disposition of assets, or issuance of equity. Continuing social uncertainty in the Middle East and North Africa and economic uncertainty in the United States, Europe and China 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.

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. Our ability to utilize our Common Stock to raise capital may be negatively affected by declines in the price 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.

Business Combinations

On October 8, 2012, the Company received regulatory approval and acquired the remaining 30% working interest in four blocks in Brazil pursuant to the terms of a purchase and sale agreement dated January 20, 2012. With the exception of one block which has three producing wells, the remaining blocks are unproved properties. The Company paid initial cash purchase consideration of $35.5 million. Contingent consideration up to an additional $3.0 million may be payable dependent on production volumes from the acquired blocks.

On March 18, 2011, we completed the acquisition of all the issued and outstanding common shares and warrants of Petrolifera pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011. Petrolifera is a Calgary-based oil, natural gas and NGL exploration, development and production company active in Argentina, Colombia and Peru. As indicated in the allocation of the consideration transferred, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, we reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, we recognized a gain on acquisition of $21.7 million in the consolidated statement of operations in the year ended December 31, 2011. The gain reflected the impact on Petrolifera's pre-acquisition market value resulting from their lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

For further details reference should be made to Note 3 of the consolidated financial statements in the section entitled "*Financial Statements and Supplementary Data*".

Consolidated Results of Operations

				Year Ended December 31,	
(Thousands of U.S. Dollars)	2012	% Change	2011	% Change	2010
Oil and natural gas sales	$ 583,109	(2)	$ 596,191	60	$ 373,286
Interest income	2,078	71	1,216	4	1,174
	585,187	(2)	597,407	60	374,460
Operating expenses	124,903	44	86,497	46	59,446
DD&A expenses	182,037	(21)	231,235	41	163,573
G&A expenses	58,882	(2)	60,389	50	40,241
Other gain	(9,336)	—	—	—	—
Equity tax	—	(100)	8,271	—	—
Financial instruments gain	—	(100)	(1,522)	—	(44)
Gain on acquisition	—	(100)	(21,699)	—	—
Foreign exchange loss (gain)	31,338	—	(11)	(100)	16,838
	387,824	7	363,160	30	280,054
Income before income taxes	197,363	(16)	234,247	148	94,406
Income tax expense	(97,704)	(9)	(107,330)	88	(57,234)
Net income	$ 99,659	(21)	$ 126,917	241	$ 37,172
Production					
Oil and NGL's, bbl	5,934,107	(3)	6,118,705	17	5,228,554
Natural gas, Mcf	1,501,070	6)	1,411,188	425	268,776
Total production, BOE (1)	6,184,286	(3)	6,353,903	20	5,273,350
Average Prices					
Oil and NGL's per bbl	$ 97.31	1	$ 96.60	36	$ 71.19
Natural gas per Mcf	$ 3.76	3	$ 3.65	(6)	$ 3.90
Consolidated Results of Operations per BOE					
Oil and natural gas sales	$ 94.29	—	$ 93.83	33	$ 70.79
Interest income	0.34	79	0.19	(14)	0.22
	94.63	1	94.02	32	71.01
Operating expenses	20.20	48	13.61	21	11.27
DD&A expenses	29.44	(19)	36.39	17	31.02
G&A expenses	9.52	—	9.50	25	7.63
Other gain	(1.51)	—	—	—	—
Equity tax	—	(100)	1.30	—	—
Financial instruments gain	—	(100)	(0.24)	—	(0.01)
Gain on acquisition	—	(100)	(3.42)	—	—
Foreign exchange loss (gain)	5.07	—	—	(100)	3.19
	62.72	10	57.14	8	53.10
Income before income taxes	31.91	(13)	36.88	106	17.91
Income tax expense	(15.80)	(6)	(16.89)	56	(10.85)
Net income	$ 16.11	(19)	$ 19.99	183	$ 7.06

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

Consolidated Results of Operations for the Year Ended December 31, 2012, Compared with the Results for the Year Ended December 31, 2011

Net income for the year ended December 31, 2012, was $99.7 million, a 21% decrease from 2011. On a per share basis, net income decreased to $0.35 per share basic and diluted from $0.46 per share basic and $0.45 per share diluted in 2011. For the year ended December 31, 2012, decreased DD&A, G&A and income tax expenses, the realization of a recovery of previously unrecognized value added tax which occurred upon the completion of a reorganization of companies and their Colombian branches and the absence of the Colombian equity tax expense were more than offset by decreased oil and natural gas sales and increased operating expenses and foreign exchange losses and the absence of the 2011 gain on acquisition. Net income in 2011 included a gain on the acquisition of Petrolifera of $21.7 million.

Oil and NGL production, NAR and adjusted for inventory changes, for the year ended December 31, 2012, decreased to 5.9 MMbbl compared with 6.1 MMbbl in 2011 due to pipeline disruptions and the effect of a change in the sales point in Colombia. As a result of entering into new oil sales and transportation agreements with Ecopetrol as of February 1, 2012, which changed the sales point of our oil from Orito station to the Port of Tumaco, our oil inventory increased and now includes oil in the OTA pipeline and associated Ecopetrol owned facilities. Production during the year ended December 31, 2012, reflects approximately 162 days of oil delivery restrictions in Colombia.

Average realized oil prices increased by 1% to $97.31 per bbl from $96.60 per bbl for the year ended December 31, 2012. We received a premium to West Texas Intermediate ("WTI") in Colombia during the year ended December 31, 2012. WTI oil prices for the year ended December 31, 2012, were $94.20 per bbl compared with $95.06 per bbl in 2011. Average Brent oil prices for the year ended December 31, 2012, were $111.67 per bbl compared with $111.26 per bbl in 2011.

Revenue and other income for the year ended December 31, 2012, decreased to $585.2 million from $597.4 million in 2011 as a result of decreased production, partially offset by increased realized prices.

Operating expenses for the year ended December 31, 2012, were $124.9 million, or $20.20 per BOE, compared with $86.5 million, or $13.61 per BOE, in 2011. The increase in operating expenses was primarily due to an increase of $29.3 million in Colombia mainly due to OTA pipeline oil transportation costs of $3.77 per BOE, previously deducted from realized sales prices and now included as operating costs due to the change in sales point in February 2012, and increased trucking to other sales points due to OTA pipeline disruptions.

DD&A expenses for the year ended December 31, 2012, decreased to $182.0 million from $231.2 million in 2011. DD&A expenses for the year ended December 31, 2012, included a $20.2 million ceiling test impairment in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. DD&A expenses in 2011 included a $42.0 million ceiling test impairment in our Peru cost center related to drilling costs from a dry well and seismic costs on relinquished blocks and a $25.7 million ceiling test impairment loss in our Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. On a per BOE basis, the depletion rate decreased by 19% to $29.44 from $36.39. The decrease was mainly due to lower impairment charges of $3.42 per BOE in the year ended December 31, 2012, compared with $10.65 per BOE in 2011 and increased reserves being only partially offset by increased costs in the depletable base.

G&A expenses for the year ended December 31, 2012, of $58.9 million decreased by 2% from $60.4 million in 2011. Increased employee related costs and bank fees reflecting expanded operations were more than offset by increased recoveries, higher capitalized costs in Peru and the absence of expenses related to the 2011 Petrolifera acquisition. G&A expenses in 2011 included $1.2 million of expenses associated with the acquisition of Petrolifera and $1.6 million of interest on the Petrolifera debt. G&A expenses per BOE in the year ended December 31, 2012, of $9.52 were comparable with $9.50 in 2011.

Other gain in the year ended December 31, 2012, relates to a value added tax recovery resulting from the completion of a reorganization of companies and their Colombian branches in the Colombian reporting segment during the fourth quarter of 2012.

Equity tax in the year ended December 31, 2011, represented a Colombian tax of 6% which was calculated based on our Colombian segment's balance sheet equity 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.

Gain on acquisition of $21.7 million in the year ended December 31, 2011, related to the Petrolifera acquisition.

For the year ended December 31, 2012, the **foreign exchange loss** was $31.3 million, of which $17.1 million was an unrealized non-cash foreign exchange loss. The realized foreign exchange loss in 2012 primarily arose upon payment of 2011 Colombian income tax liabilities. For the year ended December 31, 2011, there was an unrealized non-cash foreign exchange gain of $2.2 million, but this was almost entirely offset by realized foreign exchange losses. The Colombian Peso strengthened by 9.0% and weakened by 1.5% against the U.S. dollar in the year ended December 31, 2012 and 2011, respectively. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation is the main source of the unrealized exchange losses or gains.

Income tax expense was $97.7 million for the year ended December 31, 2012, compared with $107.3 million in 2011. The decrease was primarily due to lower income before tax. The effective tax rate was 50% in the year ended December 31, 2012, compared with 46% in 2011. The higher effective tax rate was primarily due to a non-taxable gain on the acquisition of Petrolifera recorded in 2011, an increase in non-deductible royalty payments, the impact of branch and other foreign loss pick-ups, an increase in the non-deductible foreign currency translation adjustments and other permanent difference in 2012. These factors were partially offset by the impact of foreign taxes as compared with the U.S. statutory rate and a lower valuation allowance in 2012.

For 2012, the differential between the effective tax rate of 50% and the 35% U.S. statutory rate was primarily attributable to non-deductible foreign currency translation adjustments, non-deductible royalty payments, other permanent differences, and an increase in valuation allowances. For 2011, the variance between the effective tax rate of 46% and the 35% U.S. statutory rate was mainly attributable to non-deductible royalty payments and an increase in valuation allowance offset partially by the inclusion of the non-taxable gain on acquisition and the positive impact of branch and other foreign loss pick-ups.

During 2012, a reorganization was completed which resulted in the combination of two Colombian branches. As a result of this merger, certain tax loss balances carried forward were utilized in the current year. The utilization of losses had no net impact on the tax provision as the decrease in the current tax expense was offset by an increase in the deferred tax expense. In addition, as previously discussed, a $9.3 million gain was recorded on a value added tax receivable which was previously treated as unrecoverable but, as a result of the reorganization transaction, is now considered to be recoverable. For tax purposes, this is a permanent difference as the gain is not taxable in Colombia.

Consolidated Results of Operations for the Year Ended December 31, 2011, Compared with the Results for the Year Ended December 31, 2010

Net income was $126.9 million, or $0.46 per share basic and $0.45 per share diluted, in 2011 compared with $37.2 million, or $0.15 per share basic and $0.14 per share diluted, in 2010. Increased oil and natural gas sales due to increased production and higher realized oil prices, a $21.7 million gain on the Petrolifera acquisition and the absence of foreign exchange losses were partially offset by a $42.0 million impairment loss in the Peru cost center, a $25.7 million impairment loss in the Argentina cost center, a Colombian equity tax of $8.3 million and increased operating, DD&A and G&A expenses.

Oil and NGL production, NAR and inventory changes, in 2011 increased to 6.1 MMbbl, a 17% improvement compared with 5.2 MMbbl in 2010. The increase was due to improved production from the Moqueta, Jilguero and Juanambu fields, production from Petrolifera and the reduced impact of pipeline interruptions. Petrolifera's oil and NGL production for the period since the acquisition date, NAR, was 0.5 MMbbl. Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010, and February 7, 2011, which reduced sales through the Ecopetrol-operated Trans-Andean oil pipeline ("the OTA pipeline"). During 2010 and February 2011, sections of the OTA pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol for 22 days.

Average realized oil prices in 2011 increased by 36% to $96.60 per barrel from $71.19 per barrel in 2010 reflecting higher WTI oil prices and the premium to WTI received in Colombia during 2011. Average WTI for 2011 was $95.06 as compared with $79.43 in 2010.

Increased production and higher oil prices resulted in a 60% increase in **revenue and other income** to $597.4 million for 2011 compared with $374.5 million in 2010.

Operating expenses for 2011 amounted to $86.5 million, or $13.61 per BOE, compared with $59.4 million or $11.27 per BOE, in 2010. The increase in operating expenses was mainly due to an increase of $18.3 million in operating costs in Argentina ($15.9 million related to properties acquired from Petrolifera), an increase of $7.7 million in Colombia and $1.0 million in Brazil as a result of expanded operations.

DD&A expenses for 2011 increased to $231.2 million compared with $163.6 million in 2010. DD&A expenses for 2011 includes a $42.0 million ceiling test impairment for our Peru cost center relating to seismic and drilling costs from two blocks which were relinquished, a $25.7 million impairment loss in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes and

$18.4 million of depletion, depreciation and accretion related to properties acquired from Petrolifera. DD&A expenses in 2010 included a $23.6 million ceiling test impairment in our Argentina cost center, of which $17.9 million related to the abandonment of the GTE.St.VMor-2001 sidetrack operations. The remaining small increase in DD&A was due to higher production levels and increased future development costs included in the depletable base, partially offset by an increase in year-end reserves as compared with 2010. On a BOE basis, DD&A in 2011 was $36.39 compared with $31.02 for 2010, representing a 17% increase resulting from ceiling test impairment losses and increased future development costs, partially offset by increased reserves. Impairment charges were $10.65 per BOE in the year ended December 31, 2011, compared with $4.48 per BOE in 2010.

G&A expenses of $60.4 million for 2011 were 50% higher than in 2010 due to increased employee related costs reflecting the expanded operations in all business segments, $1.2 million of expenses associated with the acquisition of Petrolifera and the inclusion of Petrolifera G&A expenses of $7.3 million (including interest on bank debt of $1.6 million, which was retired in August 2011). G&A expenses per BOE increased 25% to $9.50 per BOE compared with $7.63 per BOE for 2010 due to the same factors.

Equity tax represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years.

The **financial instruments** gain primarily relates to the fair value assigned to warrants issued in connection with the acquisition of Petrolifera. These warrants expired unexercised during August 2011.

The **gain on acquisition** of $21.7 million in 2011 relates to the acquisition of Petrolifera. This gain reflects the impact on Petrolifera's pre-acquisition market value of its lack of liquidity and capital resources required to maintain production and reserves and further develop and explore its inventory of prospects.

There were essentially no **foreign exchange gains** in 2011 as a result of an unrealized non-cash foreign exchange gain of $2.2 million being offset by realized foreign exchange losses. The non-cash foreign exchange gain primarily relates to the translation of deferred tax liabilities. This compares to a foreign exchange loss of $16.8 million recorded in 2010, of which $14.4 million was an unrealized non-cash foreign exchange loss. Under GAAP, deferred taxes are considered a monetary liability and require translation from local currency to U.S. dollar functional currency at each balance sheet date. This translation results in the recognition of unrealized exchange losses or gains. The Colombian Peso devalued by 1.5% against the U.S. dollar in the year ended December 31, 2011, resulting in an unrealized foreign exchange gain which was offset by realized foreign exchange losses. In 2010, the Colombian Peso strengthened against the U.S. dollar by 6%.

Income tax expense for 2011 was $107.3 million compared with $57.2 million in 2010. This represents an increase of 88%, primarily as a result of higher net income in Colombia. For the year ended December 31, 2011, the effective income tax rate was 46% compared with 61% in 2010 due to a decrease in non-taxable foreign currency translation adjustments and the non-taxable gain on acquisition in 2011, partially offset by an increase in the valuation allowance on deferred tax assets mainly in Peru. The variance in the effective tax rates compared with the 35% U.S. statutory rate is attributable to the same factors and other permanent differences.

2013 Work Program and Capital Expenditure Program

In December 2012, we announced the details of our 2013 capital program. We have planned a 2013 capital program of $363 million consisting of: $224 million for Colombia; $67 million for Brazil; $31 million for Argentina; $38 million for Peru; and $3 million associated with corporate activities. Of this, $202 million is for drilling, $65 million is for facilities, pipelines and other; $93 million is for G&G expenditures; and $3 million is for corporate activities. Of the $202 million allocated to drilling, approximately $101 million is for exploration and the balance is for appraisal and development drilling.

Our 2013 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 are financing our capital program through cash flows from operations, cash on hand and potential periodic draws from our revolving credit facility, 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 2013 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Segmented Results – Colombia

			Year Ended December 31,		
(Thousands of U.S. Dollars)	**2012**	% Change	2011	% Change	2010
Oil and natural gas sales	**$ 493,615**	(9)	$ 543,999	51	$ 359,302
Interest income	**667**	36	492	7	460
	494,282	(9)	544,491	51	359.762
Operating expenses	**87,410**	50	58,081	15	50,431
DD&A expenses	**122,055**	(14)	141,133	6	133,728
G&A expenses	**23,019**	(8)	25,116	65	15,216
Other gain	**(9,336)**	—	—	—	—
Equity tax	**—**	(100)	8,271	—	—
Foreign exchange loss (gain)	**26,660**	—	(1,626)	(109)	17,901
	249,808	8	230,975	6	217,276
Income before income taxes	**$ 244,474**	(22)	$ 313,516	120	$ 142,486
Production					
Oil and NGL's, bbl	**4,785,643**	(11)	5,348,885	8	4,944,510
Natural gas, Mcf	**154,702**	(42)	267,612	—	268.776
Total production, BOE (1)	**4,811,427**	(11)	5,393,487	8	4,989,306
Average Prices					
Oil and NGL's per bbl	**$ 103.04**	2	$ 101.42	40	$ 72.45
Natural gas per Mcf	**$ 3.16**	(45)	$ 5.72	47	$ 3.90
Segmented Results of Operations per BOE					
Oil and natural gas sales	**$ 102.59**	2	$ 100.86	40	$ 72.01
Interest income	**0.14**	56	0.09	—	0.09
	102.73	2	100.95	40	72.10
Operating expenses	**18.17**	69	10.77	7	10.11
DD&A expenses	**25.37**	(3)	26.17	(2)	26.80
G&A expenses	**4.78**	3	4.66	53	3.05
Other gain	**(1.94)**	—	—	—	—
Equity tax	**—**	(100)	1.53	—	—
Foreign exchange loss (gain)	**5.54**	—	(0.30)	(108)	3.59
	51.92	21	42.83	(2)	43.55
Income before income taxes	**$ 50.81**	(13)	$ 58.12	104	$ 28.55

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

Segmented Results of Operations – Colombia for the Year Ended December 31, 2012, Compared with the Results for the Year Ended December 31, 2011

For the year ended December 31, 2012, **income before income taxes** was $244.5 million compared with $313.5 million in 2011. The decrease was due to lower oil and natural gas sales primarily due to reduced production and increased operating expenses and foreign exchange losses, partially offset by decreased DD&A and G&A expenses, the recognition of a gain relating to the recovery of value added tax and the absence of equity tax.

On February 1, 2012, the sales point for the majority of our oil sales in the Putumayo Basin changed. Ecopetrol now takes title at the Port of Tumaco on the Pacific coast of Colombia rather than at the entry into the OTA pipeline. As a result, our reported oil inventory increased, representing ownership of oil in the OTA pipeline and associated Ecopetrol owned facilities. OTA transportation costs were previously factored into the price we received for oil, but, due to the changes in sales point, are now invoiced separately and included in operating costs. This change resulted in an increase in OTA oil transportation costs of $3.77 per bbl during year ended December 31, 2012.

Oil and NGL production, NAR and adjusted for inventory changes, for the year ended December 31, 2012, decreased to 4.8 MMbbl compared with 5.3 MMbbl for 2011 due to the impact of pipeline disruptions and the effect of a change in the sales point, which decreased production and increased inventory, partially offset by increased production from new producing wells. Production during the year ended December 31, 2012, reflects approximately 162 days of oil delivery restrictions in Colombia. We continued production at a reduced rate while the OTA pipeline was down, selling a portion of our oil through trucking and storing excess oil. The disruptions resulted in a reduction in oil production of approximately 4,000 BOPD NAR in the year ended December 31, 2012. In 2012, our NAR inventory increased by approximately: 196 Mbbl in Ecopetrol's facilities as a result of the change in sales point and OTA pipeline disruptions; 36 Mbbl in our own storage facilities as a result of OTA pipeline disruptions; and; 110 Mbbl as a result of the terms of a sales agreement with a third party. Sales to a third party increased oil inventory due to a protracted sales cycle whereby the transfer of ownership occurs upon export. Increases in production resulted from the development of the Moqueta field with six producing wells and production in the Garibay Block from the Jilguero-1 and -2 and Melero-1 wells.

As a result of achieving gross field production of five MMbbl in our Costayaco field, we are subject to an additional government royalty payable. This royalty is calculated on 30% of field production revenue over an inflation adjusted trigger point. That trigger point for Costayaco oil was $31.29 for 2012. Production revenue for this calculation is based on production volumes net of other government royalty volumes. Average government royalties at Costayaco with gross production of 17,000 BOPD and $100 WTI price per bbl are approximately 27.5%, including the additional government royalty of approximately 20.2%. The Colombian National Hydrocarbon Agency ("ANH") sliding scale royalty at 17,000 BOPD is approximately 9.2% and this royalty is deductible prior to calculating the additional government royalty.

Revenue and other income decreased by 9% to $494.3 million for the year ended December 31, 2012, as compared with $544.5 million in 2011.

For the year ended December 31, 2012, the average realized price per bbl for oil increased by 2% to $103.04 compared with 2011. As discussed above, effective February 1, 2012, the average realized price per bbl in Colombia increased due to the new sales agreement with Ecopetrol. Higher prices were partially offset by the effect of the settlement of a royalty dispute. During the second quarter of 2012, the recognition of additional royalties resulting from an arbitrator's decision on a dispute with a third party relating to the calculation of the third party's net profits interest on 50% of production from the Chaza Block in Colombia resulted in a $10.9 million revenue reduction. This amount related to July 2009 to May 2012 production. The recognition of this royalty resulted in a $2.27 per BOE reduction in the average realized price in the year ended December 31, 2012. The decision will increase future net profit interests payable to this third party. The third party royalty settlement represented less than 1% of the reported revenue for the periods under dispute and it is not expected to have a materially different effect on future revenue.

Operating expenses increased by 50% to $87.4 million for the year ended December 31, 2012, from $58.1 million in 2011. On a per BOE basis, operating expenses increased by 69% to $18.17 for the year ended December 31, 2012, from $10.77 in 2011. As discussed above, effective February 1, 2012, operating expenses per BOE increased due to the $3.77 per bbl OTA pipeline oil transportation costs now charged as operating costs. Additionally, operating expenses per BOE were higher due to increased trucking as a result of the pipeline disruptions and increased trucking to other sales points, additional maintenance, civil works and environmental activities and a higher percentage of production being from the Moqueta, Jilguero and Melero fields, which have higher per BOE operating costs. Workover costs increased by $0.44 per BOE compared with 2011 due to increased workovers in the Costayaco, Moqueta and Juanambu fields.

DD&A expenses decreased by 14% to $122.1 million for the year ended December 31, 2012, from $141.1 million in 2011. The decrease was primarily due to increased reserves, partially offset by increased costs in the depletable base. On a per BOE basis, DD&A expenses decreased by 3% to $25.37 for the year ended December 31, 2012.

For the year ended December 31, 2012, **G&A expenses** decreased by 8% to $23.0 million ($4.78 per BOE) from $25.1 million ($4.66 per BOE) in 2011 due to increased G&A allocations and recoveries.

Other gain in the year ended December 31, 2012, relates to a recovery of previously unrecognized value added tax which occurred upon the completion of a reorganization of companies and their Colombian branches in the Colombian reporting segment during the fourth quarter of 2012. Upon the completion of the reorganization, the combined entity had sufficient revenue to utilize the tax credits.

Equity tax in the year ended December 31, 2011, represented a Colombian tax of 6% on a legislated measure which was based on our Colombian segment's balance sheet equity at January 1, 2011.

For the year ended December 31, 2012, the **foreign exchange loss** was $26.7 million, of which $17.1 million was an unrealized non-cash foreign exchange loss. In the year ended December 31, 2011, we incurred a foreign exchange gain of $1.6 million of which $0.9 million was an unrealized non-cash foreign exchange gain.

Segmented Results of Operations – Colombia for the Year Ended December 31, 2011, Compared with the Results for the Year Ended December 31, 2010

For the year ended December 31, 2011, **income before income taxes** from Colombia amounted to $313.5 million compared with income before taxes of $142.5 million recorded in 2010. The increase is mainly due to increased oil sales due to increased production and higher prices and a foreign exchange gain, partially offset by increases in operating, DD&A and G&A expenses and Colombian equity tax of $8.3 million.

In 2011, **production of oil and NGLs**, NAR, increased by 8% to 5.3 MMbbl compared with 4.9 MMbbl in 2010. The increase in production was primarily due to the development of the Moqueta field with six producing wells, the commencement of production in the Garibay Block from the Jilguero -1 and -2 wells and increased production in the Guayuyaco Block from the new Juanambu -3 well and a full year of production from Juanambu -2. Production from the Costayaco field was consistent with the prior year. Production from two new wells, Costayaco-12 and -13, was offset by the effects of reservoir management intended to slow production declines.

Production during the first quarter of 2011 was adversely affected by a maintenance program at the Tumaco Port offloading terminal between December 28, 2010, and February 7, 2011, which reduced sales through the OTA pipeline. During 2010, sections of the OTA pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol for 29 days (7 days in June and 22 days in September).

Revenue and other income in 2011 increased by 51% to $544.5 million compared with 2010. Oil and natural gas sales were positively impacted by higher net realized oil prices in 2011 and increased production. The average net realized price for oil in 2011 was $101.42 per barrel, an increase of 40% from 2010. We received a premium to WTI during 2011 related to Colombian Pacific Blend prices.

Operating expenses for the year ended December 31, 2011, increased to $58.1 million, or $10.77 per BOE, from $50.4 million, or $10.11 per BOE, in 2010. Operating expenses per BOE were higher in 2011 due to long-term testing and slickline service costs partially offset by reduced transportation and workover costs. Significant long-term testing costs were incurred at Jilguero -1 and slickline service costs were incurred at Costayaco and Moqueta. Transportation costs were 11% lower than the prior year due to lower trucking costs as a result of the reduced impact of pipeline disruptions and pipeline pumping optimization. Workover costs were 45% lower than the prior year mainly due to fewer workovers in the Chaza Block. Petrolifera's operating expenses for the post acquisition period were $1.2 million.

For 2011, **DD&A expenses** increased to $141.1 million from $133.7 million in 2010. Petrolifera's DD&A expense for the post acquisition period was $4.3 million. The remainder of the increase was attributable to higher production levels partially offset by a small reduction in the depletion rate to $26.17 per BOE compared with $26.80 per BOE in 2010.

G&A expenses increased to $25.1 million ($4.66 per BOE) from $15.2 million ($3.05 per BOE) in 2010. The increase was mainly due to increased salaries and stock-based compensation resulting from an increased headcount, the inclusion of Petrolifera's G&A expense of $3.2 million and consulting fees related to expanded operations.

Equity tax of $8.3 million in 2011 represents a Colombian tax of 6% on a legislated measure which is based on our Colombian segment's balance sheet equity at January 1, 2011. The equity tax is assessed every four years. 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.

The results for 2011 include a **foreign exchange gain** of $1.6 million, of which $0.9 million is an unrealized non-cash foreign exchange gain on the translation of Colombian peso denominated deferred taxes to the U.S. dollar functional currency. For 2010, the foreign exchange loss was $17.9 million, of which $14.6 million was unrealized.

Capital Program – Colombia

Capital expenditures in our Colombian segment during the year ended December 31, 2012, were $153.3 million. The following table provides a breakdown of capital expenditures in the three years ended December 31, 2012:

	Year Ended December 31,		
(Millions of U.S. Dollars)	2012	2011	2010
Drilling and completions	$ 103.1	$ 105.3	$ 60.2
Facilities and equipment	26.3	33.0	25.2
G&G	14.5	30.0	22.0
Other	9.4	34.3	(1.9)
	$ 153.3	$ 202.6	$ 105.5

The significant elements of our 2012 capital program in Colombia were:

- On the Chaza Block (100% WI, operated), we drilled and completed the Costayaco-15 and Costayaco-16 development wells and drilled the Costayaco-17 development well in the Costayaco field. We also drilled and completed initial testing of the Moqueta-7 development well and commenced drilling the Moqueta-8 development well in the Moqueta field.
- Together with our partner, we successfully drilled and tested the Ramiriqui-1 oil exploration well on the Llanos-22 Block (45% WI, non-operated).
- We drilled the Bordon-1 oil exploration well on the Garibay Block (50% WI, non-operated), the Florida West exploration well on the Sierra Nevada Block (100% WI, operated) and the La Vega Este-1 oil exploration well on the Azar Block (100% WI, operated). These wells were plugged and abandoned. We also commenced drilling the Turpial-1 oil exploration well on the Turpial Block (50% WI, operated).
- We acquired 3-D seismic on the Costayaco, Moqueta and Verdayaco fields in the Chaza Block, the Guayuyaco Block (70% WI, operated), the Magdalena Block (100% WI, operated), the Putumayo 1 Block (55% WI, operated) and the Rumiyaco Block (100% WI, operated) and conducted surface and subsurface geological studies on the Cauca 6 Block (100% WI, operated) and Cauca 7 Block (100% WI, operated).
- We also continued facilities work at the Costayaco and Moqueta fields.

During the fourth quarter of 2012, we were the successful bidder in the 2012 Colombia Bid Round on the Sinu-1 and Sinu-3 Blocks of the Sinu Basin in northern Colombia. We hold a 60% operated WI in the Sinu-1 Block and a 51% operated WI in the Sinu-3 Block.

Outlook – Colombia

The 2013 capital program in Colombia is $224 million with $119 million allocated to drilling, $39 million to facilities and pipelines and $66 million for G&G expenditures.

Our planned work program for 2013 in Colombia includes drilling one gross oil exploration well on each of the Chaza and Putumayo-1 Blocks (100 % WI, operated) and two gross exploration wells on the Guayuyaco Block (70% WI, operated). We plan to drill six gross development wells and convert an existing well on the Garibay Block (50 % WI, non-operated) to a water injector well. Development wells are planned for the Chaza (both Costayaco and Moqueta fields) and Llanos-22 Blocks.

We also plan to acquire 2-D seismic on the Cauca-6, Cauca-7, Putumayo-10, Magdalena, Piedemonte Norte and Piedemonte Sur Blocks and 3-D seismic on the Garibay and Putumayo-1 Blocks. Facilities work is also planned for the Chaza, Garibay and Santana Blocks.

Segmented Results – Argentina

(Thousands of U.S. Dollars)	2012	% Change	2011	% Change	2010
					Year Ended December 31,
Oil and natural gas sales	$ 79,642	66	$ 48,016	243	$ 13,984
Interest income	355	438	66	154	26
	79,997	66	48,082	243	14,010
Operating expenses	32,696	21	27,076	207	8,808
DD&A expenses	31,466	(31)	45,506	55	29,416
G&A expenses	12,159	56	7,805	172	2,868
Foreign exchange loss	2,616	693	330	100	165
	78,937	(2)	80,717	96	41,257
Income (loss) before income taxes	$ 1,060	(103)	$ (32,635)	20	$ (27,247)
Production					
Oil and NGL's, bbl	1,047,265	44	726,762	156	284,044
Natural gas, Mcf	1,346,368	18	1,143,576	—	—
Total production, BOE (1)	1,271,660	39	917,358	223	284,044
Average Prices					
Oil and NGL's per bbl	$ 71.12	16	$ 61.10	24	$ 49.23
Natural gas per Mcf	$ 3.83	21	$ 3.16	—	$ —
Segmented Results of Operations per BOE					
Oil and natural gas sales	$ 62.63	20	$ 52.34	6	$ 49.23
Interest income	0.28	300	0.07	(22)	0.09
	62.91	20	52.41	6	49.32
Operating expenses	25.71	(13)	29.52	(5)	31.01
DD&A expenses	24.74	(50)	49.61	(52)	103.56
G&A expenses	9.56	12	8.51	(16)	10.10
Foreign exchange loss	2.06	472	0.36	(38)	0.58
	62.07	(29)	88.00	(39)	145.25
Income (loss) before income taxes	$ 0.84	(102)	$ (35.59)	(63)	$ (95.93)

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

Segmented Results of Operations – Argentina for the Year Ended December 31, 2012, Compared with the Results for the Year Ended December 31, 2011

For the year ended December 31, 2012, **income before income taxes** in Argentina was $1.1 million compared with loss before taxes of $32.6 million in 2011. In 2011, a ceiling test impairment charge of $25.7 million was recorded in the Argentina cost center. In 2012, increased oil and natural gas sales and the absence of the impairment charge more than offset increased operating and G&A expenses and foreign exchange losses.

Total production of oil and gas from the Argentina segment increased by 39% to 1.3 MMBOE, NAR and adjusted for inventory changes, for the year ended December 31, 2012, compared with 0.9 MMBOE in 2011. The acquisition of Petrolifera on March 18, 2011, added seven blocks in the Neuquen Basin, including production from four blocks, to the Argentina segment. Production in the year ended December 31, 2012, included Petrolifera production of 0.7 MMBOE, NAR and adjusted for inventory changes, which was a 40% increase from 0.5 MMBOE in 2011 due to a full 12 months of production.

Oil and NGL production, NAR and adjusted for inventory changes, increased 44% to 1.0 MMbbl for the year ended December 31, 2012, compared with 0.7 MMbbl in 2011. The increase was primarily due to production from the Proa-2 well, in the Surubi Block, which began production in April 2012.

Natural gas production, NAR, was 1.3 Bcf in the year ended December 31, 2012, compared with 1.1 Bcf in 2011. The increase was mainly attributable to a full year of production from Petrolifera's properties.

Revenue and other income increased by 66% to $80.0 million for the year ended December 31, 2012, compared with $48.1 million in 2011, due to increased production volumes and increased prices.

Average oil prices increased by 16% in the year ended December 31, 2012, compared with 2011. Due to the Argentina regulatory regime, the average oil price we received for production from our blocks during the year ended December 31, 2012, was $71.12 per bbl. Currently most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis. During 2012, we were able to negotiate higher oil prices with refineries as a result of the Argentina government's decision to allow an increase in domestic petroleum product prices; however, prices have now stabilized.

Operating expenses increased by 21% to $32.7 million for the year ended December 31, 2012, compared with $27.1 million in 2011. The increase was due to higher production volumes. On a per BOE basis, operating expenses decreased by 13% to $25.71 for the year ended December 31, 2012, from $29.52 in 2011. The decrease in operating costs on a per BOE basis was due to increased production from the Surubi Block, which has lower operating costs per BOE due to high volumes produced.

DD&A expenses decreased by 31% to $31.5 million for the year ended December 31, 2012, compared with $45.5 million in 2011. DD&A expenses in 2011 included a ceiling test impairment charge for the Argentina cost center of $25.7 million. The 2011 impairment loss resulted from an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. In 2012, the impact of the absence of the impairment charge was partially offset by the impact of higher production volumes. On a per BOE basis, DD&A expenses were $24.74 for the year ended December 31, 2012, 50% lower than DD&A expenses in 2011 of $49.61 mainly due to the ceiling test impairment charge of $28.02 per BOE in 2011.

G&A expenses were $12.2 million ($9.56 per BOE) in the year ended December 31, 2012, compared with $7.8 million ($8.51 per BOE) in 2011. For the year ended December 31, 2012, G&A expenses increased due to a $1.9 million loss recorded against a value added tax receivable balance due from a former partner and increased salaries related expenses due to an increased headcount from expanded operations. G&A expenses in the year ended December 31, 2011, included $1.6 million of interest expense on debt acquired on the Petrolifera acquisition which was repaid in August 2011, when Argentina's regulatory requirements allowed its repayment.

For the year ended December 31, 2012, the **foreign exchange loss** was $2.6 million, compared with $0.3 million in 2011. The loss primarily relates to realized foreign exchange losses on monetary assets in Argentina during the year. The Argentina Peso weakened by 14% and 9% against the U.S. dollar in the year ended December 31, 2012, and 2011, respectively, and the net asset balance exposed to foreign exchange losses was higher throughout 2012 as compared to 2011 as a result of increased production and sales.

Segmented Results of Operations – Argentina for the Year Ended December 31, 2011, Compared with the Results for the Year Ended December 31, 2010

For the year ended December 31, 2011, **loss before income taxes** in Argentina amounted to $32.6 million compared with $27.2 million in 2010. Loss before income tax included a ceiling test impairment charge for the Argentina cost center of $25.7 million in 2011 and $23.6 million in 2010. In 2011, increased oil and natural gas sales were more than offset by increased operating, depletion and G&A expenses and an increase in the foreign exchange loss. Results of the Argentina segment were significantly affected by the inclusion of Petrolifera's results since the acquisition date. The impact of Petrolifera on the financial and operational results of the Argentina segment is discussed below.

Oil and NGL production, NAR, increased 156% to 0.7 MMbbl compared with 0.3 MMbbl for 2010. The increase resulted from the inclusion of Petrolifera production of 0.5 MMbbl, NAR, in 2011.

Natural gas sales, NAR, relate solely to Petrolifera's properties. Natural gas sales amounted to 1.1 Bcf in 2011. Overall, total production of oil and gas from the Argentina segment increased by 223% to 0.9 MMBOE in 2011. Due to the Argentina regulatory regime, the average oil price we received for production from our blocks during 2011 was approximately $61.10 per barrel. Currently most oil and gas producers in Argentina are operating without sales contracts for periods longer than several months. We are continuing deliveries to refineries and are negotiating a price for those deliveries on a regular and short-term basis.

Revenue and other income increased by 243% to $48.1 million in 2011 compared with $14.0 million in 2010. The increase was primarily due to higher production due to the inclusion of Petrolifera's oil and gas production and increased prices. Average regulated oil prices increased by 24% in 2011 compared with 2010. The Argentina segment realized $0.6 million from the sale of Petroleum Plus program credits during the fourth quarter of 2011. These credits are granted by the Argentina government to companies for new production of natural gas or oil, either from new discoveries, enhanced recovery techniques or reactivation of older fields.

Operating expenses in 2011 amounted to $27.1 million compared with $8.8 million in 2010. Petrolifera's operating expenses were $15.9 million in 2011. Operating expenses were $29.52 per BOE in 2011 compared with $31.01 per BOE in 2010. Transportation costs decreased by $1.91 per BOE a result of a higher percentage of production being from blocks with lower per BOE transportation costs, such as the Puesto Morales Block.

DD&A expenses in 2011 were $45.5 million compared with $29.4 million in 2010. DD&A expenses included a ceiling test impairment charge for the Argentina cost center of $25.7 million in 2011 and $23.6 million in 2010. The impairment loss in 2011 resulted from an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. The impairment loss in 2010 included $17.9 million relating to the abandonment of the sidetrack operations at the GTE.St.VMor-2001 well and $5.2 million resulting from reduced reserves due to increases in estimated future operating costs. Petrolifera's depreciation, depletion and accretion expense was $14.0 million in 2011. DD&A expenses per BOE in 2011 were $49.61, significantly lower than DD&A expenses in 2010 of $103.56 due to the ceiling test impairment charge of $83.08 per BOE in 2010 compared with $28.02 in 2011.

G&A expenses in 2011 were $7.8 million compared with $2.9 million in 2010. The increase was primarily due to the inclusion of Petrolifera's G&A for the period after acquisition ($3.2 million, including interest expense on bank debt of $1.6 million which was repaid in August 2011) and increased headcount and consulting fees as a result of expanded operations.

Capital Program – Argentina

Capital expenditures in our Argentina segment during the year ended December 31, 2012, were $40.7 million. Capital expenditures in 2012 included drilling of $31.9 million, G&G expenditures of $4.1 million, facilities of $2.3 million and other expenditures of $2.4 million.

The significant elements of our 2012 capital program in Argentina were:

- We successfully drilled and completed the Proa-2 development well on the Surubi Block (85% WI, operated). This well began production in April 2012.
- We drilled and completed seven development wells and commenced drilling an additional two development wells on the Puesto Morales Block (100% WI, operated). We completed one development well on the Rinconada Sur Block (100% WI, operated) and, together with our partner, we drilled three gross development wells on the Rinconada Norte Block (35% WI, non-operated).

  One of the Rinconada Norte Block development wells was completed during the year and two were in progress at year-end
- On the Rinconada Norte Block, together with our partner we drilled four gross exploration wells. One exploration well was producing at year-end, one was plugged and abandoned and two were under evaluation. On the Puesto Guevara Block, we drilled one exploration well, which was plugged and abandoned, and we subsequently relinquished our interest in this block.
- On the Puesto Morales Block we also continued a well workover program, commenced a waterflood program and performed facility upgrades.

Outlook – Argentina

The 2013 capital program in Argentina is $31 million with $19 million allocated to drilling, $6 million to facilities and pipelines, and $6 million to G&G expenditures.

Our planned work program for 2013 in Argentina includes drilling one gross exploration well on the Santa Victoria Block (increased from 50% to 100% WI, subject to government approval, operated), five development wells on the Puesto Morales Block and workovers on existing wells. We also plan to acquire G&G on the Puesto Morales Block and the Valle Morado Block and perform facilities work on the El Chivil Block.

Segmented Results – Peru

		Year Ended December 31,			
(Thousands of U.S. Dollars)	**2012**	% Change	2011	% Change	2010
Interest income	**$ 49**	(65)	$ 140	—	$ —
Operating expenses	**160**	(50)	$ 322	56	207
DD&A expenses	**1,234**	(97)	42,035	—	40
G&A expenses	**4,573**	8	4,249	269	1,153
Foreign exchange (gain) loss	**(425)**	96	(217)	(823)	30
	5,542	(88)	46,389	3,144	1,430
Loss before income taxes	**$ (5,493)**	(88)	$ (46,249)	3,134	$ (1,430)

Segmented Results of Operations – Peru for the Year Ended December 31, 2012, Compared with the Results for the Years Ended December 31, 2011, and December 31, 2010

DD&A expenses for the year ended December 31, 2011, included $42.0 million of impairment charges relating to drilling costs from a dry well and seismic costs on blocks which were relinquished.

G&A expenses were $4.6 million in the year ended December 31, 2012, compared with $4.2 million in 2011. The increase was due to higher salaries expense resulting from expanded operations partially offset by increased capitalized costs. The increase in G&A expenses in 2011 compared with 2010 was due to higher salaries, stock-based compensation and consulting fees resulting from increased activity.

Capital Program – Peru

Capital expenditures in our Peruvian segment for the year ended December 31, 2012, were $62.9 million. Capital expenditures in 2012 included drilling of $31.1 million, acquisitions of $12.5 million, G&G expenditures of $17.4 million and other expenditures of $1.9 million.

The significant elements of our 2012 capital program in Peru were:

- On Block 95 (100% WI, operated), we completed civil construction of a drilling platform and dock facility and began drilling the Bretaña Norte 95-2-1XD exploration well on December 15, 2012. We also applied for a variety of permits in preparation for drilling the oil exploration well and for future seismic programs.
- On Block 123 and Block 129, we assumed 100% WI, subject to government approval, and we were appointed operator as of January 1, 2013.
- We acquired 2-D seismic on Block 123 and Block 129.
- On Block 107 (100% WI, operated), we acquired a carried working interest that was held by a third party and advanced permitting for drilling and, on Block 133 (100% WI, operated), we performed G&G studies.

Outlook – Peru

The 2013 capital program in Peru is $38 million with $21 million allocated to drilling, $2 million for facilities and $15 million for G&G expenditures.

In 2013, we completed drilling the Bretaña Norte 95-2-1XD exploration well on Block 95 and obtained initial well-log results, which indicated an oil saturated reservoir. We plan to extend the exploration well with a horizontal leg to initiate long-term testing. Timing for initiation of the long-term testing has not been determined yet, but it is expected to commence within a period of 12 months, subject to facilities upgrade, and execution of crude oil transportation and delivery agreements.

Our planned work program for 2013 also includes the acquisition of 2-D seismic on Block 107, the commencement of an aeromagnetic and aerogravity survey and Environmental Impact Assessments on Block 133 and obtaining the necessary environmental and social permits to implement future seismic programs on Block 95, Block 123 and Block 129.

Segmented Results – Brazil

					Year Ended December 31,
(Thousands of U.S. Dollars)	**2012**	% Change	2011	% Change	2010
Oil and natural gas sales	**$ 9,852**	136	$ 4,176	—	$ —
Interest income	**607**	623	84	9	77
	10,459	146	4,260	5,432	77
Operating expenses	**4,637**	356	1,018	—	—
DD&A expenses	**26,300**	—	1,819	—	77
G&A expenses	**2,092**	(54)	4,542	74	2,609
Foreign exchange loss	**1,973**	160	759	(285)	(411)
	35,002	330	8,138	258	2,275
Loss before income taxes	**$ (24,543)**	533	$ (3,878)	(76)	$ (2,198)
Production[1]					
Oil and NGL's, bbl	**101,199**	135	43,058	—	—
Average Prices					
Oil and NGL's per bbl	**$ 97.35**	—	$ 96.99	—	$ —
Segmented Results of Operations per BOE					
Oil and natural gas sales	**$ 97.35**		$ 96.99	—	$ —
Interest income	**6.00**	208	1.95	—	—
	103.35	4	98.94	—	—
Operating expenses	**45.82**	94	23.64	—	—
DD&A expenses	**259.88**	515	42.25	—	—
G&A expenses	**20.67**	(80)	105.49	—	—
Foreign exchange loss	**19.50**	11	17.63	—	—
	345.87	83	189.01	—	—
Loss before income taxes	**$ (242.52)**	169	$ (90.07)	—	$ —

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

Segmented Results of Operations – Brazil for the Year Ended December 31, 2012, Compared with the Results for the Years Ended December 31, 2011, and December 31, 2010

For the year ended December 31, 2012, **loss before income taxes** was \$24.5 million compared with \$3.9 million in 2011. Loss before income taxes in 2012 included a ceiling test impairment loss of \$20.2 million relating to seismic and drilling costs on Block BM-CAL-10.

Oil and natural gas sales and operating expenses represented sales and operating expenses from Block 155 in the Tiê field in the onshore Recôncavo Basin. We began recording revenue from production from this block on June 15, 2011, the date regulatory approval was received for the purchase of our 70% working interest in the block. In 2012, production was shut in between the expiry of the long-term test phase on July 31, 2012, and the declaration of commerciality for the Tiê field. Production recommenced on September 21, 2012, after the receipt of regulatory approval. We were also subject to gas flaring restrictions during the third quarter of 2012, which were subsequently eased and are subject to re-approval for periods after December 31, 2013. We increased our working interest in Block 155 to 100% in October 2012.

Average Brent oil prices for the year ended December 31, 2012, were \$111.67 per bbl (year ended December 31, 2011 – \$111.26 per bbl). The price we receive in Brazil is at a discount to Brent due to a refining discount.

DD&A expenses in the year ended December 31, 2012, included a ceiling test impairment loss of \$20.2 million. The impairment loss related to seismic and drilling costs on Block BM-CAL-10. The remainder of the increase is due to increased reserves being more than offset by increased costs in the depletable base.

G&A expenses were \$2.1 million in the year ended December 31, 2012, compared with \$4.5 million in 2011 and \$2.6 million in 2010. We began recognizing production in Brazil in June 2011 upon receipt of regulatory approval. This resulted in a significant increase in the costs that were directly attributable to operations and exploration and development and a corresponding reduction in G&A expenses in 2012 compared with 2011.

Capital Program – Brazil

Capital expenditures in our Brazilian segment during the year ended December 31, 2012, were \$55.2 million. Capital expenditures in 2012 included drilling of \$52.0 million, facilities of \$1.1 million, G&G expenditures of \$0.2 million and \$1.9 million of other expenditures. Additionally, we spent \$36.6 million (including contingent consideration) on the acquisition of the remaining 30% working interest in our properties in Brazil, which was accounted for as a business combination.

The significant elements of our 2012 capital program in Brazil were:

- On October 8, 2012, the Company received regulatory approval and acquired the remaining 30% working interest in Blocks REC-T-129, REC-T-142, REC-T-155, and REC-T-224 pursuant to the terms of a purchase and sale agreement dated January 20, 2012. The purchase consideration was \$35.5 million. Contingent consideration of up to an additional \$3.0 million may be payable dependent on production volumes from the acquired blocks.
- We drilled and completed two gross development wells, 3-GTE-03-BA and 4-GTE-04-BA, in the Tiê field on Block REC-T-155 (100% WI, operated) and drilled a horizontal oil exploration well, 1-GTE-05HP-BA, on Block REC-T-142 (100% WI, operated).
- We received regulatory approval for our farm-in on Block BM-CAL-7 (10% WI, non-operated) in the offshore Camamu Basin. Purchase consideration of \$0.7 million was paid and the assignment became effective on April 3, 2012. We also purchased an existing 3-D seismic program on this block.
- During 2011, we entered into a farm-out agreement with Statoil do Brasil Ltda. ("Statoil") pursuant to which we would receive an assignment from Statoil of a non-operated 15% working interest in Block BM-CAL-10. During the first quarter of 2012, in accordance with the terms of the farm-out agreement for Block BM-CAL-10, we gave notice to Statoil that we would not enter into and assume our share of the work obligations of the second exploration period of the block. As a result, the farm-out agreement terminated and we will not receive any interest in this block. Pursuant to the farm-out agreement, we were obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to a well that was drilled during the term of the farm-out agreement. The notice of withdrawal was a trigger for payment of amounts that would otherwise have been due if the farm-out agreement had closed and we had acquired a working interest. We recorded \$23.8 million of capital expenditures in relation to the Block BM-CAL-10 farm-out agreement in 2012.

Outlook – Brazil

The 2013 capital program in Brazil is \$67 million with \$43 million allocated to drilling, \$18 million to facilities and pipelines and \$6 million for G&G and other expenditures.

Our planned work program for 2013 in Brazil includes drilling two horizontal sidetrack oil exploration wells on Block REC-T-155 and Block REC-T-142 (100% WI and operator), additional completion work on the 3-GTE-03-BA and 3-GTE-04-BA producing wells in the Tiê field and fracture stimulation operations on Block REC-T-142. We also plan to perform facilities and pipeline work on Block REC-T-155.

Results – Corporate Activities

					Year Ended December 31,
(Thousands of U.S. Dollars)	2012	% Change	2011	% Change	2010
Interest income	$ 400	(8)	$ 434	(29)	611
DD&A expenses	982	32	742	138	312
G&A expenses	17,039	(9)	18,677	2	18,395
Financial instruments gain	—	(100)	(1,522)	—	(44)
Gain on acquisition	—	(100)	(21,699)	—	—
Foreign exchange (gain) loss	514	(31)	743	(188)	(847)
	18,535	(706)	(3,059)	(117)	17,816
(Loss) income before income taxes	$ (18,135)	(619)	$ 3,493	(120)	$ (17,205)

Results of Operations – Corporate Activities for the Year Ended December 31, 2012, Compared with the Results for the Years Ended December 31, 2011, and December 31, 2010

G&A expenses in the year ended December 31, 2012, were $17.0 million compared with $18.7 million in 2011. In the year ended December 31, 2012, increases in salaries due to expanded operations were more than offset by an increase in the amount of costs recovered from business units, a reduction in consulting costs and the absence of Petrolifera acquisition costs ($1.2 million in the year ended December 31, 2011). In 2011, the increase in G&A expenses compared to 2010 related to increased salaries and stock-based compensation and increased consulting charges due to expanded operations in all countries and Petrolifera acquisition costs.

Gain on acquisition in the year ended December 31, 2011, related to the acquisition of Petrolifera.

Liquidity and Capital Resources

At December 31, 2012, we had cash and cash equivalents of $212.6 million compared with $351.7 million at December 31, 2011, and $355.4 million at December 31, 2010.

We believe that our cash resources, including cash on hand, cash generated from operations and our revolving credit facility, will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for 2013, given current oil price trends and production levels. In accordance with our investment policy, cash balances are held in our primary cash management bank, HSBC Bank plc., in interest earning current accounts or are invested in U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At December 31, 2012, 89% of our cash and cash equivalents was held by our foreign subsidiaries. This balance is not available to fund domestic operations unless funds are repatriated. At this time, we do not intend to repatriate funds, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The governments in Brazil and Argentina require us to register funds that enter and exit the country with the central bank in each country. In Brazil, Argentina and Colombia, all transactions must be carried out in the local currency of the country. In Colombia, we participate in the Special Exchange Regime, which allows for the deposit of our revenue to our branch offshore Colombia in U.S. dollars. Beginning in 2013, transfer of branch profits are considered as dividends subject to a 25% tax but only in the case where those dividends have not already been subject to Colombian tax. We do not currently expect that this change in Colombian law will have a material consequence to us.

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentine subsidiaries to make dividends or loan payments to us. At December 31, 2012, $16.4 million, or 8%, of our cash and cash equivalents was deposited with banks in Argentina. We expect to use these funds for the 2013 Argentina work program and operations.

Effective July 30, 2010, through our wholly-owned subsidiary, Solana Resources Limited ("Solana"), we established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve-based facility has a maximum borrowing base of up to $100 million and is supported by the present value of our Colombian petroleum reserves of two of our subsidiaries with operating branches in Colombia – Gran Tierra Energy Colombia Ltd. and Petrolifera Petroleum Exploration (Colombia) Ltd, and our subsidiary in Brazil – Gran Tierra Energy Brasil Ltda. The initial committed borrowing base was $20 million and, effective August 2, 2012, the committed borrowing base was increased to $50 million. Effective February 15, 2013, the borrowing base was increased to $100 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants.

On May 17, 2012, BNP Paribas sold Solana's credit facility to Wells Fargo Bank National Association, as part of the sale of its North American reserve-based lending business. At December 31, 2012, and December 31, 2011, we had not drawn down any amounts under this facility.

Cash Flows

During the year ended December 31, 2012, our cash and cash equivalents decreased by $139.1 million as a result of cash used in investing activities of $299.7 million, partially offset by cash provided by operating activities of $156.3 million and cash provided by financing activities of $4.3 million.

Cash provided by operating activities in the year ended December 31, 2012, was primarily affected by increased operating expenses and realized foreign exchange losses and a $167.4 million increase in assets and liabilities from operating activities. The main changes in assets and liabilities from operating activities were as follows: accounts receivable and other long-term assets increased by $56.7 million due to the change in the timing of collection of Ecopetrol receivables, new customers in Colombia and increased oil and gas sales in Argentina; inventory increased by $18.2 million primarily due to a change in the sales point under new sales agreements with Ecopetrol and increased sales to other third parties with different sales points due to the timing of the transfer of risks in Colombia; accounts payable and accrued liabilities decreased by $8.4 million due to the payment of royalties and reduced royalties payable resulting from lower production, partially offset by increased operating cost and other payables as a result of increased activity in all business units; and taxes receivable and payable decreased by $83.7 million as a result of a decrease in taxes payable due utilization of tax losses and tax deductions resulting from a corporate reorganization, and lower taxable income in Colombia, partially offset by an increase in taxes receivable due to value added tax and income tax recoveries in Colombia generated upon completion of the same corporate reorganization.

Net cash provided by operating activities in the year ended December 31, 2011, was positively affected by increased production and improved oil prices and a decrease in non-cash working capital. These positive contributions were partially offset by increased operating and G&A expenses to support expanded operations. In year ended December 31, 2010, net cash provided by operating activities was positively affected by the increases in oil production and prices, offset by higher receivables related to oil sales.

Cash outflows from investing activities in the year ended December 31, 2012, included capital expenditures of $276.1 million and cash paid for the 30% working interest acquisition in Brazil of $35.5 million, partially offset by a decrease in restricted cash of $11.9 million related to this same acquisition. Cash outflows from investing activities in the year ended December 31, 2011, included capital expenditures of $333.2 million and an increase in restricted cash of $10.2 million, partially offset by proceeds on sale of asset-backed commercial paper ("ABCP") of $22.7 million, $7.7 million cash acquired through the Petrolifera acquisition and $4.5 million of proceeds from disposition of oil and gas properties. Cash outflows from investing activities in the year ended December 31, 2010, primarily related to capital expenditures, partially offset by proceeds from the sale of an overriding royalty right.

Cash provided by financing activities in the years ended December 31, 2012, 2011 and 2010 related to proceeds from issuance of shares of Common Stock upon the exercise of stock options and, in 2011, was more than offset by the settlement of $31.3 million of bank debt and $22.8 million of an ABCP line of credit. Both the bank debt and the ABCP line of credit were acquired through the Petrolifera acquisition.

Off-Balance Sheet Arrangements

As at December 31, 2012, 2011 and 2010 we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of December 31, 2012:

		Year ending December 31					
(Thousands of U.S. Dollars)	Total	2013	2014	2015	2016	2017	2018
Oil transportation services	$ 28,354	$ 5,077	$ 3,405	$ 3,405	$ 3,405	$ 3,405	$ 9,657
Drilling and G&G	40,524	38,171	2,353	—	—	—	—
Completions	26,188	14,699	7,368	4,121	—	—	—
Facility construction	18,484	11,623	6,861	—	—	—	—
Operating leases	4,115	1,928	1,706	477	4	—	—
Software and telecommunication	1,744	1,538	74	9	123	—	—
Consulting	1,592	1,592	—	—	—	—	—
	$ 121,001	$ 74,628	$ 21,767	$ 8,012	$ 3,532	$ 3,405	$ 9,657

Total contractual obligations at December 31, 2011, were $146.2 million, and the decrease in 2012 was due to the amortization of transportation contracts in Colombia, amortization of information technology contracts and operating leases, and the completion of the Moqueta facilities construction in 2012 partially offset by drilling and completion commitments for Block 95 in Peru.

At December 31, 2012, we had provided promissory notes totaling $34.2 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Related Party Transactions

On January 12, 2011, we entered into an agreement to sublease office space to a company of which our President and Chief Executive Officer serves as an independent director. The term of the sublease ran from February 1, 2011, to January 30, 2013, and the sublease payment was $4,500 per month plus approximately $4,700 of operating and other expense; however, the sublease was terminated on October 31, 2012, and we are now occupying this office space.

On August 7, 2012, we entered into a contract related to the Brazil drilling program with a company for which one of our directors is a shareholder (less than 10% shareholding) and director. During the year ended December 31, 2012, $1.7 million was incurred and capitalized under this contract and at December 31, 2012, $1.1 million was included in accounts payable relating to this contract. Similarly, on August 3, 2010, we entered into a contract related to the Peru drilling program with the same company and $2.8 million was incurred and capitalized under this contract during the year ended December 31, 2011, and at December 31, 2011, $nil was included in accounts payable relating to this contract.

On February 1, 2009, we entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was $8,000 per month plus approximately $4,700 for operating and other expenses.

Critical Accounting Policies and Estimates

The preparation of financial statements under GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities as well as the revenues and expenses reported and disclosure of contingent liabilities. Changes in these estimates related to judgments and assumptions will occur as a result of changes in facts and circumstances or discovery of new information, and, accordingly, actual results could differ from amounts estimated.

On a regular basis we evaluate our estimates, judgments and assumptions. We also discuss our critical accounting policies and estimates with the Audit Committee of the Board of Directors.

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

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

We follow the full cost method of accounting for our oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 to our annual consolidated financial statements.

Under the full cost method of accounting, all costs incurred in the acquisition, exploration and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations ("ARO"), and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

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

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

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

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

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

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas, and the applicable discount rate, that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2012, ceiling tests were based on wellhead prices per BOE as of the first day of each month within that twelve month period of $103.57 for Colombia, $66.12 for Argentina and $95.38 for Brazil.

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

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

We assessed our oil and gas properties for impairment as at December 31, 2012, and found no impairment write-down was required based on our calculations for any cost center. At March 31, 2012, we recorded a ceiling test impairment loss of $20.2 million in our Brazil cost center related to seismic and drilling costs on Block BM-CAL-10. We assessed our oil and gas properties for impairment as at December 31, 2011, and found no impairment write-down was required based on our calculations for our Colombia and Brazil cost centers. As a result of assessing oil and gas properties in our Peru and Argentina cost centers, ceiling test impairment losses of $42.0 million and $25.7 million respectively were recorded. The 2011 impairment charge in the Peru cost center related to seismic and drilling costs from dry wells on two blocks which were relinquished. The 2011 impairment charge in the Argentina cost center related to an increase in estimated future operating and capital costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes. We assessed our oil and gas properties for impairment as at December 31, 2010, and found no impairment write-down was required based on our assumptions for our Colombia cost center. A ceiling test impairment loss of $23.6 million was recorded in our Argentina cost center in 2010 as a result of the abandonment of the GTE.St.VMor-2001 sidetrack operations, an increase in estimated future operating costs to produce our remaining Argentina proved reserves and a decrease in reserve volumes.

Because of the volatile nature of oil and gas prices, it is not possible to predict the timing or magnitude of full cost writedowns. In addition, due to the inter-relationship of the various judgments made to estimate proved reserves, it is impractical to provide quantitative analyses of the effects of potential changes in these estimates. However, decreases in estimates of proved reserves would generally increase our depletion rate and, thus, our depletion expense. Decreases in our proved reserves may result from lower market prices, which may make it uneconomic to drill for and produce higher cost fields. The decline in proved reserve estimates may impact the outcome of the full cost ceiling test previously discussed. In addition, increases in costs required to develop our reserves would increase the rate at which we record DD&A expenses.

Unproved properties

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

Asset Retirement Obligations

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

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

It is difficult to determine the impact of a change in any one of our assumptions. As a result, we are unable to provide a reasonable sensitivity analysis of the impact a change in our assumptions would have on our financial results.

Allocation of Consideration Transferred in Business Combinations

The acquisition of properties in Brazil in 2012 was accounted for using the acquisition method whereby the assets acquired and liabilities assumed were recorded at their fair values at the acquisition date. The fair value of the consideration transferred was equal to the fair value of the net assets acquired and no gain or goodwill was recorded on acquisition.

The acquisition of Petrolifera in 2011 was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby the Petrolifera assets acquired and liabilities assumed were recorded at their fair values at the acquisition date with the excess of the fair values of the net assets acquired over the consideration transferred recorded as a gain on acquisition. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, was subject to estimates which include various assumptions including the fair value of proved and unproved reserves of the acquired company as well as the future production and development costs and future oil and gas prices.

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

Goodwill

Goodwill represents the excess of the aggregate of the consideration transferred over the net identifiable assets acquired and liabilities assumed. The goodwill on our balance sheet resulted from the Solana and Argosy Energy International L.P. acquisitions, in 2008 and 2006 respectively, and relates entirely to the Colombia reporting unit. At each reporting date, we assess qualitative factors to determine whether it is more likely than not that the fair value of the reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. Changes in our future cash flows, operating results, growth rates, capital expenditures, cost of capital, discount rates, stock price or related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

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

Income Taxes

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

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

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

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

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

Legal and Other Contingencies

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

Stock-Based Compensation

Our stock-based compensation cost is measured based on the fair value of the award on the grant date. The compensation cost is recognized net of estimated forfeitures over the requisite service period. GAAP requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

We utilize the Black-Scholes option pricing model to measure the fair value of all of our stock options. The use of such models requires substantial judgment with respect to expected life, volatility, expected returns and other factors. Expected volatility is based on the historical volatility of our shares. We use historical experience for exercises to determine expected life. We are responsible for determining the assumptions used in estimating the fair value of our share based payment awards.

New Accounting Pronouncements

We have reviewed all recently issued, but not yet adopted, accounting standard updates in order to determine their effects, if any, on our consolidated financial statements. Based on that review, we believe that the implementation of these standards will not materially impact our consolidated financial position, operating results, cash flows, or disclosure requirements.

Quantitative and Qualitative Disclosures About Market Risk

Our principal market risk relates to oil prices. Most of our revenues are from oil sales at prices which reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to WTI or Brent and adjusted for quality each month. In Argentina, a further discount factor which is related to a tax on oil exports establishes a common pricing mechanism for all oil produced in the country, regardless of its destination.

Foreign currency risk is a factor for our company but is ameliorated to a large degree by the nature of expenditures and revenues in the countries where we operate. We have not engaged in any formal hedging activity with regard to foreign currency risk. Our reporting currency is U.S. dollars and essentially 100% of our revenues are related to the U.S. dollar price of WTI or Brent oil.

In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars. In Argentina and Brazil, prices for oil are in U.S. dollars, but revenues are received in local currency translated according to current exchange rates. The majority of our capital expenditures within Argentina and Brazil are based on U.S. dollar prices, but are paid in local currency translated according to current exchange rates. The majority of our capital expenditures in Peru are in U.S. dollars. The majority of income and value added taxes and G&A expenses in all locations are in local currency. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso due to our current and deferred tax liabilities, which are monetary liabilities, denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. For the year ended December 31, 2012, our realized foreign exchange loss was $14.3 million (2011 – $2.2 million). A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

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

Financial Statements and Supplementary Data

Report of Independent Registered Chartered Accountants

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

We have audited the accompanying consolidated financial statements of Gran Tierra Energy Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of operations and retained earnings, consolidated statements of shareholders' equity, and consolidated statements of cash flows for each of the years in the three-year period ended December 31, 2012, and the notes to the financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Gran Tierra Energy Inc. and its subsidiaries as at December 31, 2012 and 2011, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2012 in accordance with accounting principles generally accepted in the United States of America.

Other Matters

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte LLP
Independent Registered Chartered Accountants

Calgary, Canada
February 26, 2013

Consolidated Statements of Operations and Retained Earnings

(Thousands of U.S. Dollars, Except Share and Per Share Amounts)	**2012**	Year Ended December 31, 2011	2010
REVENUE AND OTHER INCOME			
Oil and natural gas sales	**$ 583,109**	$ 596,191	$ 373,286
Interest income	**2,078**	1,216	1,174
	585,187	597,407	374,460
EXPENSES			
Operating	**124,903**	86,497	59,446
Depletion, depreciation, accretion and impairment (Note 6)	**182,037**	231,235	163,573
General and administrative	**58,882**	60,389	40,241
Other gain (Note 9)	**(9,336)**	—	—
Equity tax (Note 9)	**—**	8,271	—
Financial instruments gain (Note 3)	**—**	(1,522)	(44)
Gain on acquisition (Note 3)	**—**	(21,699)	—
Foreign exchange loss (gain)	**31,338**	(11)	16,838
	387,824	363,160	280,054
INCOME BEFORE INCOME TAXES	**197,363**	234,247	94,406
Income tax expense (Note 9)	**(97,704)**	(107,330)	(57,234)
NET INCOME AND COMPREHENSIVE INCOME	**99,659**	126,917	37,172
RETAINED EARNINGS, BEGINNING OF YEAR	**185,014**	58,097	20,925
RETAINED EARNINGS, END OF YEAR	**$ 284,673**	$ 185,014	$ 58,097
NET INCOME PER SHARE — BASIC	**$ 0.35**	$ 0.46	$ 0.15
NET INCOME PER SHARE — DILUTED	**$ 0.35**	$ 0.45	$ 0.14
WEIGHTED AVERAGE SHARES OUTSTANDING – BASIC (Note 7)	**280,741,255**	273,491,564	253,697,076
WEIGHTED AVERAGE SHARES OUTSTANDING – DILUTED (Note 7)	**284,172,254**	281,287,002	264,304,831

(See notes to the consolidated financial statements)

Consolidated Balance Sheets

(Thousands of U.S. Dollars, Except Share and Per Share Amounts)	As at December 31, 2012 2012	2011
ASSETS		
Current Assets		
Cash and cash equivalents	$ 212,624	$ 351,685
Restricted cash	1,404	1,655
Accounts receivable (Note 5)	119,844	69,362
Inventory (Note 5)	33,468	7,116
Taxes receivable	39,922	21,485
Prepaids	4,074	3,597
Deferred tax assets (Note 9)	2,517	3,029
Total Current Assets	413,853	457,929
Oil and Gas Properties (using the full cost method of accounting)		
Proved	813,247	618,982
Unproved	383,414	417,868
Total Oil and Gas Properties	1,196,661	1,036,850
Other capital assets	8,765	7,992
Total Property, Plant and Equipment (Note 6)	1,205,426	1,044,842
Other Long-Term Assets		
Restricted cash	1,619	13,227
Deferred tax assets (Note 9)	1,401	4,747
Taxes receivable	1,374	—
Other long-term assets	6,621	3,454
Goodwill	102,581	102,581
Total Other Long-Term Assets	113,596	124,009
Total Assets	$ 1,732,875	$ 1,626,780
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable (Note 10)	$ 102,263	$ 82,189
Accrued liabilities (Note 10)	66,418	66,832
Taxes payable	22,339	95,482
Deferred tax liabilities (Note 9)	337	—
Asset retirement obligation (Note 8)	28	326
Total Current Liabilities	191,385	244,829
Long-Term Liabilities		
Deferred tax liabilities (Note 9)	225,195	186,799
Equity tax payable (Note 9)	3,562	6,484
Asset retirement obligation (Note 8)	18,264	12,343
Other long-term liabilities	3,038	2,007
Total Long-Term Liabilities	250,059	207,633
Commitments and Contingencies (Note 11)		
Shareholders' Equity		
Common stock (Note 7) (268,482,445 and 262,304,249 shares of Common Stock and 13,421,488 and 16,323,819 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2012, and December 31, 2011, respectively)	7,986	7,510
Additional paid in capital	998,772	980,014
Warrants (Note 7)	—	1,780
Retained earnings	284,673	185,014
Total Shareholders' Equity	1,291,431	1,174,318
Total Liabilities and Shareholders' Equity	$ 1,732,875	$ 1,626,780

(See notes to the consolidated financial statements)

Consolidated Statements of Cash Flows

(Thousands of U.S. Dollars)		2012		2011		2010
				Year Ended December 31,		
Operating Activities						
Net income	$	99,659	$	126,917	$	37,172
Adjustments to reconcile net income to net cash provided by operating activities:						
Depletion, depreciation, accretion and impairment		182,037		231,235		163,573
Deferred tax expense (recovery) (Note 9)		26,274		(28,685)		(19,679)
Stock-based compensation (Note 7)		12,006		12,767		8,025
Unrealized gain on financial instruments (Note 3)		—		(1,354)		(44)
Unrealized foreign exchange loss (gain)		17,054		(2,232)		14,375
Settlement of asset retirement obligation (Note 8)		(404)		(345)		(286)
Other gain (Note 9)		(9,336)		—		—
Equity tax		(3,534)		2,442		—
Gain on acquisition (Note 3)		—		(21,699)		—
Net change in assets and liabilities from operating activities						
Accounts receivable and other long-term assets		(56,669)		(15,627)		(5,323)
Inventory		(18,195)		(548)		(1,221)
Prepaids		(477)		(1,321)		(120)
Accounts payable and accrued and other liabilities		(8,387)		16,780		(3,176)
Taxes receivable and payable		(83,709)		35,422		10,522
Net cash provided by operating activities		156,319		353,752		203,818
Investing Activities						
Decrease (increase) in restricted cash		11,859		(10,197)		352
Additions to property, plant and equipment		(276,084)		(333,194)		(152,299)
Proceeds from disposition of oil and gas properties (Note 6)		—		4,450		7,986
Cash paid for acquisition (Note 3)		(35,495)		—		—
Cash acquired on acquisition (Note 3)		—		7,747		—
Proceeds on sale of asset-backed commercial paper (Note 3)		—		22,679		—
Net cash used in investing activities		(299,720)		(308,515)		(143,961)
Financing Activities						
Settlement of bank debt (Note 3)		—		(54,103)		—
Proceeds from issuance of shares of Common Stock		4,340		5,123		24,785
Net cash provided by (used in) financing activities		4,340		(48,980)		24,785
Net (decrease) increase in cash and cash equivalents		(139,061)		(3,743)		84,642
Cash and cash equivalents, beginning of year		351,685		355,428		270,786
Cash and cash equivalents, end of year	$	212,624	$	351,685	$	355,428
Cash	$	207,392	$	172,645	$	272,151
Term deposits		5,232		179,040		83,277
Cash and cash equivalents, end of year	$	212,624	$	351,685	$	355,428
Supplemental cash flow disclosures:						
Cash paid for interest	$	—	$	1,604	$	—
Cash paid for income taxes	$	143,498	$	67,053	$	49,088
Non-cash investing activities:						
Non-cash net assets and liabilities related to property, plant and equipment, end of year	$	75,393	$	43,333	$	48,640

(See notes to the consolidated financial statements)

Consolidated Statements of Shareholders' Equity

(Thousands of U.S. Dollars)	2012	2011	2010
		Year Ended December 31,	
Share Capital			
Balance, beginning of year	**$ 7,510**	$ 4,797	$ 1,431
Issue of shares of Common Stock	**476**	2,713	3,366
Balance, end of year	**7,986**	7,510	4,797
Additional Paid in Capital			
Balance, beginning of year	**980,014**	821,781	766,963
Issue of shares of Common Stock	**2,902**	142,109	19,119
Exercise of warrants (Note 7)	**1,590**	411	24,916
Expiry of warrants (Note 7)	**190**	—	—
Exercise of stock options (Note 7)	**960**	1,990	2,300
Stock-based compensation (Note 7)	**13,116**	13,723	8,483
Balance, end of year	**998,772**	980,014	821,781
Warrants			
Balance, beginning of year	**1,780**	2,191	27,107
Exercise of warrants (Note 7)	**(1,590)**	(411)	(24,916)
Expiry of warrants (Note 7)	**(190)**	—	—
Balance, end of year	**—**	1,780	2,191
Retained Earnings			
Balance, beginning of year	**185,014**	58,097	20,925
Net income	**99,659**	126,917	37,172
Balance, end of year	**284,673**	185,014	58,097
Total Shareholders' Equity	**$ 1,291,431**	$ 1,174,318	$ 886,866

(See notes to the consolidated financial statements)

Notes to the Consolidated Financial Statements

For the Years Ended December 31, 2012, 2011 and 2010
(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, Argentina, Peru and Brazil.

2. Significant Accounting Policies

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

Significant accounting policies are:

Basis of consolidation

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

Use of estimates

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

Cash and cash equivalents

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

Restricted cash

Restricted cash comprises cash and cash equivalents pledged to secure letters of credit and to settle asset retirement obligations. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. Cash and claims to cash that are restricted as to withdrawal or use for other than current operations or are designated for expenditure in the acquisition or construction of long-term assets are excluded from the current asset classification.

Allowance for doubtful accounts

The Company estimates losses on receivables based on known uncollectible accounts, if any, and historical experience of losses incurred. The allowance for doubtful receivables was nil at December 31, 2012, and 2011.

Inventory

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

Income taxes

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

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

Oil and gas properties

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

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

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

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

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

In exploration areas, related geological and geophysical ("G&G") costs are capitalized in unproved property and evaluated as part of the total capitalized costs associated with a property. G&G costs related to development projects are recorded in proved properties and therefore subject to amortization as incurred.

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

Asset retirement obligation

The Company records the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with an offsetting increase to the related oil and gas properties. The fair value of asset retirement obligations are measured by reference to the expected future cash outflows required to satisfy the retirement obligations discounted at the Company's credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value, while the asset retirement cost is amortized over the estimated productive life of the related assets. The accretion of the asset retirement obligation and amortization of the asset retirement cost are included in DD&A. If estimated future costs of asset retirement obligations change, an adjustment is recorded to both the asset retirement obligation and oil and gas properties. Revisions to the estimated asset retirement obligation can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

Other capital assets

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

Goodwill

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

The Company recorded $87.6 million of goodwill in relation to the acquisition of Solana Resources Limited ("Solana") in 2008 and $15.0 million of goodwill in relation to the Argosy Energy International L.P. ("Argosy") acquisition in 2006. The goodwill relates entirely to the Colombia reportable segment. The Company performed a qualitative assessment of goodwill at December 31, 2012, and based on this assessment, no impairment of goodwill was identified.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable, the sale is evidenced by a contract and collection of the revenue is reasonably assured. On February 1, 2012, the sales point for the majority of the Company's Colombian oil sales in the Putumayo Basin changed. Gran Tierra's primary customer, Ecopetrol S.A. ("Ecopetrol"), now takes title at the Port of Tumaco on the Pacific coast of Colombia rather than at the entry into the Ecopetrol-operated Trans-Andean oil pipeline ("the OTA pipeline") at the Orito Station in the Putumayo Basin. In Colombia, the Company has other sales contracts where the sales point is the purchaser's facilities or when oil is loaded into a truck at Gran Tierra's loading facility or an export tanker. In Argentina, Gran Tierra transports oil from the field to the customer's refinery or the oil terminal by pipeline or truck, where title is transferred. For the Company's gas sales in Argentina, Gran Tierra's customers take title when the gas is transferred to their pipeline. In Brazil, Gran Tierra transports product from the field to the customer's station by truck, where title is transferred. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

Stock-based compensation

The Company follows the fair-value based method of accounting for stock options granted to directors, officers and employees. Compensation expense for options granted is based on the estimated fair value, using the Black-Scholes option pricing model, at the time of grant and the expense, net of estimated forfeitures, is recognized over the requisite service period using the accelerated method. An adjustment is made to compensation expense for any difference between the estimated forfeitures and the actual forfeitures related to vested awards. The Company uses historical data to estimate option exercises, expected term and employee departure behavior used in the Black-Scholes option pricing model. Expected volatilities used in the fair value estimate are based on historical volatility of the Company's shares. The risk-free rate for periods within the expected term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant. Stock-based compensation expense is capitalized as part of oil and natural gas properties or expensed as part of operating expenses or general and administrative ("G&A") expenses, as appropriate.

Warrants

The Company issued warrants ("Replacement Warrants") in connection with its acquisition of Petrolifera Petroleum Limited ("Petrolifera") in March 2011 (Note 3). The Replacement Warrants expired unexercised during August 2011. These warrants were derivative financial instruments and were recognized at fair value in the consolidated balance sheet as a current liability and as part of the consideration paid for the acquisition. The Company determined the fair value of warrants issued using the Black-Scholes option pricing model.

Foreign currency translation

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

Gains and losses resulting from foreign currency transactions, which are transactions denominated in a currency other than the entity's functional currency, are recognized in net income.

Net income per share

Basic net 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 net 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.

Adopted Accounting Pronouncements

Goodwill

In September 2011, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2011-08, "Intangibles – Goodwill and Other (Topic 350)." The update is intended to simplify how entities test goodwill for impairment. The update permits entities to assess qualitative factors to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount and whether it is necessary to perform the two-step goodwill impairment test. This ASU was effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2011. The implementation of this update did not materially impact the Company's consolidated financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

Disclosure about Offsetting Assets and Liabilities

In December 2011, the FASB issued ASU 2011-11, "Balance Sheet – Disclosure about Offsetting Assets and Liabilities (Topic 210)." The update requires an entity to disclose information about offsetting assets and liabilities and related arrangements to enable users of its financial statements to understand the effect of those arrangements on its financial position. This ASU is effective for fiscal years, and interim periods within those fiscal years, beginning after January 1, 2013. The implementation of this update is not expected to materially impact the Company's disclosure.

3. Business Combination

Brazil

On October 8, 2012, the Company received regulatory approval and acquired the remaining 30% working interest in four blocks in Brazil pursuant to the terms of a purchase and sale agreement dated January 20, 2012. With the exception of one block which has three producing wells, the remaining blocks are unproved properties.

The Company paid initial cash purchase consideration of $28.0 million and an interim period purchase price adjustment of $7.5 million, representing the 30% share of all benefits and costs with respect to the period between the effective date and the completion of the transaction. Contingent consideration up to an additional $3.0 million may be payable dependent on production volumes from the acquired blocks.

The acquisition was accounted for as a business combination using the acquisition method, with Gran Tierra being the acquirer, whereby the assets acquired and liabilities assumed were recognized at their fair values as at October 8, 2012, the acquisition date, and the results of the blocks were included with those of Gran Tierra from that date. Fair value estimates were made based on significant unobservable (Level 3) inputs and based on the best information available at the time.

Contingent consideration was recorded on the balance sheet at the acquisition date fair value based on the consideration expected to be transferred, 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 was determined at the time of measurement in accordance with accepted valuation methods. The acquisition date fair value of the contingent consideration was $1.1 million and was recorded in other long-term liabilities. The fair value of the contingent consideration is being remeasured at the estimated fair value at each reporting period with the change in fair value recognized as income or expense in operating income. Any changes in fair value will impact earnings in such reporting period until the contingencies are resolved. There was no significant change in the fair value of the contingent consideration between October 8, 2012, and December 31, 2012.

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

(Thousands of U.S. Dollars)		
Consideration Transferred:		
Cash	$	35,495
Fair value of contingent consideration payable		1,061
	$	36,556
Allocation of Consideration Transferred (1):		
Oil and gas properties		
Proved	$	24,107
Unproved		12,859
Asset retirement obligation		(410)
	$	36,556

(1) The allocation of the consideration transferred is not final and is subject to change.

Pro forma results (unaudited)

Pro forma results related to this acquisition have not been disclosed because oil and natural gas sales and net income related to the 30% working interest for the years ended December 31, 2012, and 2011 were not material in relation to the Company's consolidated financial statements. Production from these blocks was not significant during these periods.

Petrolifera Petroleum Limited

On March 18, 2011 (the "Acquisition Date"), Gran Tierra completed its acquisition of all the issued and outstanding common shares and warrants of Petrolifera, a Canadian corporation, pursuant to the terms and conditions of an arrangement agreement dated January 17, 2011 (the "Arrangement"). Petrolifera is a Calgary based oil, natural gas and natural gas liquids exploration, development and production company active in Argentina, Colombia and Peru. The transaction contemplated by the Arrangement was effected through a court approved plan of arrangement in Canada. The Arrangement was approved at a special meeting of Petrolifera shareholders on March 17, 2011, and by the Court of Queen's Bench of Alberta on March 18, 2011.

Under the Arrangement, Petrolifera shareholders received, for each Petrolifera share held, 0.1241 of a share of Gran Tierra Common Stock, and Petrolifera warrant holders received, for each Petrolifera warrant held, 0.1241 of a warrant (a "Replacement Warrant") to purchase a share of Gran Tierra Common Stock at an exercise price of $9.67 Canadian ("CDN") dollars per share. The Replacement Warrants expired unexercised on August 28, 2011.

Gran Tierra acquired all the issued and outstanding Petrolifera shares and warrants through the issuance of 18,075,247 shares of Gran Tierra Common Stock, par value $0.001, and 4,125,036 Replacement Warrants. Upon completion of the transaction on the Acquisition Date, Petrolifera became an indirect wholly-owned subsidiary of Gran Tierra. On a diluted basis, upon the closing of the Arrangement, Petrolifera and Gran Tierra security holders owned approximately 6.6% and 93.4% of the Company, respectively, immediately following the transaction. The total consideration for the transaction was approximately $143.0 million.

The fair value of Gran Tierra's Common Stock was determined as the closing price of shares of the Common Stock of Gran Tierra as at the Acquisition Date.

The fair value of the Replacement Warrants was estimated on the Acquisition Date using the Black-Scholes option pricing model with the following assumptions:

Exercise price (CDN dollars per warrant)	$	9.67
Risk-free interest rate		1.3%
Expected life		0.45 years
Volatility		44%
Expected annual dividend per share		Nil
Estimated fair value per warrant (CDN dollars)	$	0.32

The Replacement Warrants met the definition of a derivative and, due to the fact that the exercise price of the Replacement Warrants was denominated in Canadian dollars, which is different from Gran Tierra's functional currency, the Replacement Warrants were not considered indexed to Gran Tierra's shares of Common Stock and the Replacement Warrants could not be classified within equity. Therefore, the Replacement Warrants were classified as a current liability on Gran Tierra's consolidated balance sheet. Furthermore, these derivative instruments did not qualify as fair value hedges or cash flow hedges, and accordingly, changes in their fair value were recognized as income or expense in the consolidated statement of operations with a corresponding adjustment to the fair value of derivative instruments recognized on the balance sheet. The financial instruments gain for the year ended December 31, 2011, included a $1.3 million gain arising from the fair value of the expired Replacement Warrants.

The acquisition was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera's assets acquired and liabilities assumed are recognized at their fair values as at the Acquisition Date and the results of Petrolifera have been consolidated with those of Gran Tierra from that date.

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

(Thousands of U.S. Dollars)		
Consideration Transferred:		
Shares of Common Stock issued net of share issue costs	$	141,690
Replacement warrants		1,354
	$	143,044
Allocation of Consideration Transferred:		
Oil and gas properties		
Proved	$	58,457
Unproved		161,278
Other long-term assets		4,417
Net working capital (including cash acquired of $7.7 million and accounts receivable of $6.4 million)		(17,223)
Asset retirement obligation		(4,901)
Bank debt		(22,853)
Other long-term liabilities		(14,432)
Gain on acquisition		(21,699)
	$	143,044

As shown above, the fair value of identifiable assets acquired and liabilities assumed exceeded the fair value of the consideration transferred. Consequently, Gran Tierra reassessed the recognition and measurement of identifiable assets acquired and liabilities assumed and concluded that all acquired assets and assumed liabilities were recognized and that the valuation procedures and resulting measures were appropriate. As a result, Gran Tierra recognized a gain of $21.7 million, which was reported as "Gain on acquisition" in the consolidated statement of operations. The gain reflected the impact on Petrolifera's pre-acquisition market value of a lack of liquidity and capital resources required to maintain current production and reserves and further develop and explore their inventory of prospects.

As part of the assets acquired and included in the net working capital in the allocation of the consideration transferred, the Company assigned $22.5 million in fair value to investments in notes that Petrolifera received in exchange for asset-backed commercial paper ("ABCP") with a face value of $31.3 million. On March 28, 2011, these notes were sold to an unrelated party for proceeds of $22.7 million after the associated line of credit was settled. When combined with the gain arising on expiry of the Replacement Warrants, the financial instruments gain for the year ended December 31, 2011, was $1.5 million.

The associated ABCP line of credit that Gran Tierra assumed was with a Canadian chartered bank, to a maximum of CDN$23.2 million with an initial expiry in April 2012. Gran Tierra settled this line of credit immediately after the completion of the acquisition of Petrolifera for the face value of CDN$22.5 million in borrowings plus accrued interest.

Also upon the acquisition of Petrolifera, Gran Tierra assumed a second line of credit agreement ("Second ABCP line of credit") with the same Canadian chartered bank to a maximum of CDN$5.0 million, which was fully drawn as at the Acquisition Date. This Second ABCP line of credit, which expired on April 8, 2011, was secured by ineligible master asset vehicles Classes 1 & 2 ("MAV IA 1 & 2") notes with a face value of $6.6 million. Gran Tierra retained the option to settle the Second ABCP line of credit of CDN$5.0 million through delivery to the lender of the MAV IA 1 & 2 notes. Subsequent to the acquisition, Gran Tierra elected to record this second line of credit at fair value and planned at that time to settle the debt through delivery of the MAV IA 1 & 2 notes. Accordingly, a value of $nil was recorded for the debt upon its acquisition. Gran Tierra settled such borrowings by delivery of the MAV IA 1 & 2 notes on April 8, 2011.

Gran Tierra also assumed a reserve-backed credit facility upon the Petrolifera acquisition with an outstanding balance of $31.3 million. The amount outstanding under this credit facility was included as part of net working capital in the allocation of consideration transferred. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries. The outstanding balance was repaid when the Argentina restriction preventing its repayment expired on August 5, 2011, resulting in a total debt repayment of $54.1 million, when combined with the repayment of the CDN$22.5 million ABCP line of credit. Interest expense on the credit facility for the 140-day period from the Acquisition Date to August 5, 2011, was $1.6 million. This amount is recorded in the consolidated statements of operations as part of G&A expenses in the Argentina segment.

Pro forma results (unaudited)

Pro forma results for the year ended December 31, 2011, are shown below, as if the acquisition had occurred on January 1, 2010. Pro forma results are not indicative of actual results or future performance.

		Year Ended December 31,
(Unaudited, thousands of U.S. Dollars, except per share amounts)		2011
Revenue and other income	$	606,602
Net income	$	94,094
Net income per share – basic	$	0.34
Net income per share – diluted	$	0.33

The supplemental pro forma earnings of Gran Tierra for the year ended December 31, 2011, were adjusted to exclude $4.4 million of acquisition costs recorded in G&A expenses and the $21.7 million gain on acquisition because they were not expected to have a continuing impact on Gran Tierra's results of operations. The consolidated statement of operations for the year ended December 31, 2011, included revenue of $32.5 million from Petrolifera for the period subsequent to the Acquisition Date. Petrolifera incurred a loss after tax of $8.0 million in the period from the Acquisition Date to December 31, 2011.

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, Argentina, Peru and Brazil based on geographic organization. The level of activity in Brazil was not significant at December 31, 2012, 2011 or 2010; 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 accounting policies of the reportable segments are the same as those described in Note 2. The Company evaluates reportable segment performance based on income or loss before income taxes. The segmented results include the operations of Petrolifera subsequent to March 18, 2011, the Acquisition Date (Note 3).

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

						Year Ended December 31, 2012
(Thousands of U.S. Dollars, except per unit of production amounts)	**Colombia**	**Argentina**	**Peru**	**Brazil**	**All Other**	**Total**
Oil and natural gas sales	**$ 493,615**	**$ 79,642**	**$ —**	**$ 9,852**	**$ —**	**$ 583,109**
Interest income	**667**	**355**	**49**	**607**	**400**	**2,078**
DD&A expenses	**122,055**	**31,466**	**1,234**	**26,300**	**982**	**182,037**
DD&A – per unit of production	**25.37**	**24.74**	**—**	**259.88**	**—**	**29.44**
Income (loss) before income taxes	**244,474**	**1,060**	**(5,493)**	**(24,543)**	**(18,135)**	**197,363**
Segment capital expenditures (1)	**$ 153,331**	**$ 40,653**	**$ 62,869**	**$ 55,239**	**$ 1,084**	**$ 313,176**

						Year Ended December 31, 2011
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 543,999	$ 48,016	$ —	$ 4,176	$ —	$ 596,191
Interest income	492	66	140	84	434	1,216
DD&A expenses	141,133	45,506	42,035	1,819	742	231,235
DD&A – per unit of production	26.17	49.61	—	42.25	—	36.39
Income (loss) before income taxes	313,516	(32,635)	(46,249)	(3,878)	3,493	234,247
Segment capital expenditures (2)	$ 202,551	$ 36,289	$ 36,224	$ 50,836	$ 1,747	$ 327,647

						Year Ended December 31, 2010
(Thousands of U.S. Dollars, except per unit of production amounts)	Colombia	Argentina	Peru	Brazil	All Other	Total
Oil and natural gas sales	$ 359,302	$ 13,984	$ —	$ —	$ —	$ 373,286
Interest income	460	26	—	77	611	1,174
DD&A expenses	133,728	29,416	40	77	312	163,573
DD&A – per unit of production	26.80	103.56	—	—	—	31.02
Income (loss) before income taxes	142,486	(27,247)	(1,430)	(2,198)	(17,205)	94,406
Segment capital expenditures (2)	105,482	$ 33,930	$ 23,195	$ 12,911	$ 1,521	$ 177,039

(1) In 2012, the Company also paid $35.5 million to acquire the remaining 30% working interest in four blocks in Brazil (Note 3).

(2) In 2011, amounts are net of proceeds from the farm-out of a 50% working interest in the Santa Victoria Block and the sale of a blow-out preventer, both in Argentina (Note 6). In 2011, the Company also completed its acquisition of all the issued and outstanding common shares and warrants of Petrolifera (Note 3). In 2010, amounts are net of proceeds from the sale of the Garibay overriding royalty right in Colombia (Note 6).

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.

The Company has one significant customer in Colombia, Ecopetrol. Sales to Ecopetrol accounted for 74%, 87% and 96% of the Company's consolidated revenues for the years ended December 31, 2012, 2011 and 2010, respectively.

Year Ended December 31, 2012						
(Thousands of U.S. Dollars)	**Colombia**	**Argentina**	**Peru**	**Brazil**	**All Other**	**Total**
Property, plant and equipment	**$ 840,027**	**$ 138,768**	**$ 95,940**	**$ 127,394**	**$ 3,297**	**$ 1,205,426**
Goodwill	**102,581**	**—**	**—**	**—**	**—**	**102,581**
Other assets	**222,220**	**47,038**	**10,880**	**8,498**	**136,232**	**424,868**
Total Assets	**$ 1,164,828**	**$ 185,806**	**$ 106,820**	**$ 135,892**	**$ 139,529**	**$ 1,732,875**

Year Ended December 31, 2011						
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	All Other	Total
Property, plant and equipment	$ 816,396	$ 129,072	$ 34,305	$ 61,875	$ 3,194	$ 1,044,842
Goodwill	102,581	—	—	—	—	102,581
Other assets	269,843	34,672	9,597	17,065	148,180	479,357
Total Assets	$ 1,188,820	$ 163,744	$ 43,902	$ 78,940	$ 151,374	$ 1,626,780

5. Accounts Receivable and Inventory

Accounts Receivable

As at December 31,		
(Thousands of U.S. Dollars)	**2012**	2011
Trade	**$ 116,434**	$ 66,204
Other	**3,410**	3,158
	119,844	69,362

Inventory

At December 31, 2012, oil and supplies inventories were $31.2 million and $2.3 million, respectively (December 31, 2011 – $4.7 million and $2.4 million, respectively).

6. Property, Plant and Equipment

Property, Plant and Equipment

	As at December 31, 2012			As at December 31, 2011		
(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	**$ 1,562,477**	**$ (749,230)**	**$ 813,247**	$ 1,181,503	$ (562,521)	$ 618,982
Unproved	**383,414**	**—**	**383,414**	417,868	—	417,868
	1,945,891	**(749,230)**	**1,196,661**	1,599,371	(562,521)	1,036,850
Furniture and fixtures and leasehold improvements	**7,575**	**(5,093)**	**2,482**	6,973	(4,002)	2,971
Computer equipment	**10,971**	**(5,248)**	**5,723**	8,443	(4,174)	4,269
Automobiles	**1,376**	**(816)**	**560**	1,295	(543)	752
Total Property, Plant and Equipment	**$ 1,965,813**	**$ (760,387)**	**$ 1,205,426**	$ 1,616,082	$ (571,240)	$ 1,044,842

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2012, was $168.0 million (year ended December 31, 2011 – $162.6 million; year ended December 31, 2010 – $139.2 million). A portion of depletion and depreciation expense was recorded as inventory in each year.

On June 5, 2012, the Company received regulatory approval of a farm-in agreement on a block in Colombia. This approval triggered a payment of $21.1 million related to drilling costs for a previously drilled oil exploration well, which was recorded as a capital expenditure in the second quarter of 2012.

Effective June 1, 2012, the Company entered into an agreement to acquire the remaining 40% working interest in a block in Peru. The block is an unproved property. Purchase consideration was $5.4 million and was recorded as a capital expenditure in the second quarter of 2012. The agreement is subject to government approval.

On August 26, 2010, the Company entered into an agreement to acquire a 70% working interest in four blocks in Brazil. With the exception of one block which has three producing wells, the remaining blocks are unproved properties. The agreement was effective September 1, 2010, subject to regulatory approvals, and the transaction was completed on June 15, 2011. Purchase consideration was $40.1 million and was recorded as capital expenditures in 2011 and 2010. On January 20, 2012, the Company entered into an agreement to acquire the remaining 30% working interest in these four blocks and, on October 8, 2012, received regulatory approval and acquired the remaining 30% working interest. The 30% working interest acquisition was accounted for as a business combination using the acquisition method (Note 3).

In September 2011, the Company announced two farm-out agreements with Statoil do Brasil Ltda. ("Statoil") in a joint venture with PetróleoBrasileiro S.A. pursuant to which, the Company would receive an assignment of a non-operated 10% working interest in Block BM-CAL-7 and a non-operated 15% working interest in Block BM-CAL-10. Both blocks are located in the Camamu Basin, offshore Bahia, Brazil.

During the first quarter of 2012, the Company received regulatory approval from Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") for the Block BM-CAL-7 farm-out agreement. Purchase consideration of $0.7 million was paid and the assignment became effective on April 3, 2012. This block is an unproved property.

On February 17, 2012, in accordance with the terms of the farm-out agreement for Block BM-CAL-10, the Company gave notice to Statoil that it would not enter into and assume its share of the work obligations of the second exploration period of the block. As a result, the farm-out agreement terminated and the Company did not receive any interest in this block. Pursuant to the farm-out agreement, the Company was obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to a well that was drilled during the term of the farm-out agreement. The notice of withdrawal was a trigger for payment of amounts that would otherwise have been due if the farm-out agreement had closed and the Company had acquired a working interest. In the three months ended March 31, 2012, the Company recorded a ceiling test impairment loss in the Company's Brazil cost center of $20.2 million. This impairment charge resulted from the recognition of $23.8 million of capital expenditures in relation to the Block BM-CAL-10 farm-out agreement in the first quarter of 2012.

In the year ended December 31, 2011, the Company recorded a ceiling test impairment loss in the Company's Peru cost center of $42.0 million. This impairment charge related to drilling costs from a dry well and seismic costs on blocks which were relinquished.

In the year ended December 31, 2011, the Company recorded a ceiling test impairment loss in the Company's Argentina cost center of $25.7 million. This impairment charge related to an increase in estimated future operating and capital costs to produce the Company's remaining Argentina proved reserves and a decrease in reserve volumes.

In December 31, 2010, the Company recorded a $23.6 million ceiling test impairment loss in the Company's Argentina cost center, of which $17.9 million related to the abandonment of the Valle Morado sidetrack operations and the remaining $5.7 million resulted from a decrease in reserves combined with higher forecasted operating costs to produce the remaining proved reserves.

In March 2011, the Company recorded proceeds of $3.3 million from the farm-out of a 50% interest in the Santa Victoria Block in Argentina. The Company also recorded $1.2 million from the sale of a blow-out preventer in Argentina in September 2011. In October 2010, the Company recorded proceeds of $6.4 million for the sale of an overriding royalty right in the Garibay Block in Colombia. In April 2009, Gran Tierra closed the sale of the Company's interests in the Guachiria Norte, Guachiria, and Guachiria Sur blocks in Colombia. Consideration of $7.0 million comprised an initial cash payment of $4.0 million at closing, followed by 15 monthly installments of $0.2 million each which began on June 1, 2009, and ended on August 3, 2010. The Company recorded proceeds of $1.6 million and $5.4 million in 2010 and 2009, respectively.

The amounts of G&A and stock-based compensation capitalized in each of the Company's cost centers during the years ended December 31, 2012, 2011 and 2010, respectively, were as follows:

Year Ended December 31, 2012										
(Thousands of U.S. Dollars)		**Colombia**		**Argentina**		**Peru**		**Brazil**		**Total**
Capitalized G&A, including stock-based compensation	**$**	**15,054**	**$**	**4,605**	**$**	**4,761**	**$**	**3,844**	**$**	**28,264**
Capitalized stock-based compensation	**$**	**481**	**$**	**354**	**$**	**—**	**$**	**275**	**$**	**1,110**

Year Ended December 31, 2011										
(Thousands of U.S. Dollars)		Colombia		Argentina		Peru		Brazil		Total
Capitalized G&A, including stock-based compensation	$	7,996	$	3,189	$	1,183	$	1,985	$	14,353
Capitalized stock-based compensation	$	456	$	266	$	—	$	234	$	956

Year Ended December 31, 2010					
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	4,127	1,171	287	—	5,585
Capitalized stock-based compensation	308	150	—	—	458

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. As at December 31, 2012, the Company had $175.9 million (December 31, 2011 – $274.8 million) of unproved assets in Colombia, $42.3 million (December 31, 2011 – $57.0 million) of unproved assets in Argentina, $95.1 million (December 31, 2011 – $33.7 million) of unproved assets in Peru, and $70.1 million (December 31, 2011 – $52.4 million) of unproved assets in Brazil for a total of $383.4 million (December 31, 2011 – $417.9 million). These 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 dictates whether or not future areas will be developed. The Company expects that approximately 53% of costs not subject to depletion at December 31, 2012, will be transferred to the depletable base within the next five years and the remainder in the next five to 10 years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2012:

Costs Incurred in										
(Thousands of U.S. Dollars)		**2012**		2011		2010		Prior to 2010		Total
Acquisition costs – Colombia	**$**	**—**	$	8,647	$	—	$	127,842	$	136,489
Acquisition costs – Argentina		**—**		35,051		—		—		35,051
Acquisition costs – Peru		**5,400**		23,423		2,000		—		30,823
Acquisition costs – Brazil		**12,802**		22,668		—		—		35,470
Exploration costs – Colombia		**16,092**		7,227		14,635		1,429		39,383
Exploration costs – Argentina		**(588)**		2,595		4,834		392		7,233
Exploration costs – Peru		**58,286**		6,019		—		—		64,305
Exploration costs – Brazil		**17,128**		17,532		—		—		34,660
Total oil and natural gas properties not subject to depletion	**$**	**109,120**	$	123,162	$	21,469	$	129,663	$	383,414

7. Share Capital

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

As at December 31, 2012, outstanding share capital consists of 268,482,445 shares of Common Stock of the Company, 7,197,678 exchangeable shares of Gran Tierra Exchange Co., (the "Exchangeco exchangeable shares") that will be automatically exchangeable on November 14, 2013, except under certain specified circumstances, and 6,223,810 exchangeable shares of Goldstrike Exchange Co. (the "Goldstrike exchangeable shares"), automatically exchangeable on November 10, 2013. During the year ended December 31, 2012, 482,841 shares of Common Stock were issued upon the exercise of stock options, 2,793,024 shares of Common Stock were issued upon the exercise of warrants, 1,587,302 shares of Common Stock were issued upon the exchange of the Goldstrike exchangeable shares and 1,315,029 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.

The Exchangeco exchangeable shares were issued upon acquisition of Solana. The Goldstrike exchangeable shares were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. On October 5, 2012, the automatic redemption date on the Goldstrike exchangeable shares was extended by one year to November 10, 2013. As at December 31, 2012, 95.8% of the Goldstrike exchangeable shares were held by directors and management of the Company. 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.

Stock Options

As at December 31, 2012, the Company had a 2007 Equity Incentive Plan, formed through the approval by shareholders of the amendment and restatement of the 2005 Equity Incentive Plan, under which the Company's board of directors is authorized to issue options or other rights to acquire shares of the Company's Common Stock. On June 16, 2010, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 18,000,000 shares to 23,306,100 shares. On June 27, 2012, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares.

The Company grants options to purchase shares of Common Stock to certain directors, officers, employees and consultants. Each option permits the holder to purchase one share of Common Stock at the stated exercise price. At the time of grant, the exercise price equals the market price. The options vest over three years and have a term of ten years, or three months after the grantee's end of service to the Company, whichever occurs first. Currently, the Company's practice is to issue new shares upon stock option exercise. The Company does not expect to repurchase any shares in the open market to settle any such exercises.

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

	Year Ended December 31,		
	2012	2011	2010
Dividend yield (per share)	**Nil**	Nil	Nil
Volatility	**59% to 75%**	75% to 81%	84% to 90%
Weighted average volatility	**75 %**	80 %	89%
Risk-free interest rate	**0.3% to 0.4%**	0.4% to 1.4%	0.2% to 0.5%
Expected term	**4-6 years**	4-6 years	3 years

The following table provides information about stock option activity for the year ended December 31, 2012:

	Number of Outstanding Options	Weighted Average Exercise Price $/Option
Balance, December 31, 2011	12,864,002	4.90
Granted	3,400,650	5.78
Exercised	(482,841)	(2.97)
Forfeited	(305,152)	(6.79)
Expired	(76,997)	(6.82)
Balance, December 31, 2012	**15,399,662**	**5.11**
Vested, or expected to vest, at December 31, 2012, through the life of the options	**14,669,616**	**5.03**

For the year ended December 31, 2012, 482,841 shares of Common Stock were issued upon the exercise of 482,841 stock options (2011 – 1,695,049; 2010 – 2,895,553). Cash proceeds from the exercise of stock options in the year ended December 31, 2012 were $1.4 million.

At December 31, 2012, the weighted average remaining contractual term of outstanding stock options was 7.2 years and of exercisable stock options was 6.2 years.

The weighted average grant date fair value for options granted in the year ended December 31, 2012, was $3.33 (2011 – $4.84; 2010 – $3.36). The weighted average grant date fair value for options vested in the year ended December 31, 2012, was $3.90 (2011 – $2.26; 2010 – $1.61). The total fair value of stock options vested during year ended December 31, 2012, was $10.2 million (2011 – $6.6 million; 2010 – $5.1 million).

For the year ended December 31, 2012, the stock-based compensation expense was $13.1 million (2011- $13.7 million; 2010 – $8.5 million) of which $10.9 million (2011 – $11.4 million; 2010 – $7.2 million) was recorded in G&A expenses, $1.1 million was recorded in operating expenses (2011 – $1.3 million; 2010 -$0.8 million) and $1.1 million was capitalized as part of exploration and development costs (2011 – $1.0 million; 2010 – $0.5 million).

At December 31, 2012, there was $8.2 million (December 31, 2011 – $11.7 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next three years.

The aggregate intrinsic value of options outstanding at December 31, 2012, was $17.8 million (2011 – $14.7 million; 2010 -$49.9 million) based on the Company's closing share price of $5.51 at December 31, 2012 (December 31, 2011 – $4.80; December 31, 2010 – $8.05). The aggregate intrinsic value of options exercisable at December 31, 2012, was $17.6 million (December 31, 2011 – $14.2 million; December 31, 2010 – $49.4 million). The aggregate intrinsic value of options exercised in the year ended December 31, 2012, was $1.4 million (2011 – $6.2 million; 2010 – $12.8 million). The aggregate intrinsic value of options vested, or expected to vest, at December 31, 2012, through the life of the options was $17.8 million and the weighted-average remaining contractual term of these options was 7.2 years.

Warrants

At December 31, 2011, the Company had 6,298,230 warrants outstanding to purchase 3,149,115 shares of Common Stock for $1.05 per share, expiring between June 20, 2012, and June 30, 2012. During the year ended December 31, 2012, 2,766,834 shares of Common Stock were issued upon the exercise of 5,550,668 warrants (2011 – 735,817 shares of Common Stock were issued upon the exercise of 1,471,634 warrants), 26,190 shares of Common Stock were issued with 7,143 shares withheld in lieu of a cashless exchange upon the exercise of 66,666 warrants, and 680,896 warrants expired unexercised.

Weighted Average Shares Outstanding

	Year Ended December 31,		
	2012	2011	2010
Weighted average number of common and exchangeable shares outstanding	**280,741,255**	273,491,564	253,697,076
Shares issuable pursuant to warrants	**175,061**	2,708,183	3,750,781
Shares issuable pursuant to stock options	**5,879,929**	5,143,498	7,402,966
Shares assumed to be purchased from proceeds of stock options	**(2,623,991)**	(56,243)	(545,992)
Weighted average number of diluted common and exchangeable shares outstanding	**284,172,254**	281,287,002	264,304,831

For the year ended December 31, 2012, 9,784,874 options (2011 – 3,726,999 options; 2010 – 290,000) were excluded from the diluted income per share calculation as the options were anti-dilutive.

8. Asset Retirement Obligation

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

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2012**	2011
Balance, beginning of year	**$ 12,669**	$ 4,807
Settlements	**(404)**	(345)
Disposal	**—**	(172)
Liability incurred	**5,190**	867
Liability assumed in a business combination (Note 3)	**410**	4,901
Foreign exchange	**45**	17
Accretion	**998**	673
Revisions in estimated liability	**(616)**	1,921
Balance, end of year	**$ 18,292**	$ 12,669
Asset retirement obligation – current	**$ 28**	$ 326
Asset retirement obligation – long-term	**18,264**	12,343
Balance, end of year	**$ 18,292**	$ 12,669

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 December 31, 2012, the fair value of assets that are legally restricted for purposes of settling asset retirement obligations was $1.3 million (December 31, 2011 – $0.8 million).

9. Taxes

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

(Thousands of U.S. Dollars)	2012	2011	2010
		Year Ended December 31,	
Income (loss) before income taxes			
United States	(13,918)	4,984	(16,726)
Foreign	211,281	229,263	111,132
	197,363	234,247	94,406
	35%	35%	35
Income tax expense expected	69,077	81,986	33,042
Foreign currency translation adjustments	5,473	(417)	6,409
Impact of foreign taxes	(1,833)	3,890	(3,094)
Stock-based compensation	3,982	4,013	2,381
Increase in valuation allowance	6,709	36,815	19,991
Branch and other foreign loss pick-up	(3,809)	(14,363)	(3,957)
Non-deductible third party royalty in Colombia	11,938	8,525	5,506
Enhanced tax depreciation incentive	—	—	(7,971)
Non-taxable gain on acquisition	—	(7,595)	—
Other permanent differences	6,167	(5,524)	4,927
Total income tax expense	$ 97,704	$ 107,330	$ 57,234
Current income tax expense			
United States	1,233	1,029	501
Foreign	70,197	134,986	76,412
	71,430	136,015	76,913
Deferred income tax expense (recovery)			
United States	—	—	—
Foreign	26,274	(28,685)	(19,679)
	26,274	(28,685)	(19,679)
Total income tax expense	$ 97,704	$ 107,330	$ 57,234

For the year ended December 31, 2012, other permanent differences in the rate reconciliation are tax effected at the 35% statutory rate. These differences include $11.4 million of true-up provisions and loss adjustments, $8.7 million of which are offset by a change in the valuation allowance and $2.7 million of which are subject to local tax at a rate of 1.75%.

(Thousands of U.S. Dollars)	2012	2011
	As at December 31,	
Deferred Tax Assets		
Tax benefit of loss carryforwards	$ 51,920	$ 63,910
Tax basis in excess of book basis	22,519	17,065
Foreign tax credits and other accruals	30,926	27,164
Capital losses	4,779	2,433
Deferred tax assets before valuation allowance	110,144	110,572
Valuation allowance	(106,226)	(102,796)
	$ 3,918	$ 7,776
Deferred tax assets – current	$ 2,517	$ 3,029
Deferred tax assets – long-term	1,401	4,747
	3,918	7,776
Deferred tax liabilities – current	(337)	—
Deferred tax liabilities – long-term	(225,195)	(186,799)
	$ (225,532)	$ (186,799)
Net Deferred Tax Liabilities	$ (221,614)	$ (179,023)

Undistributed earnings of foreign subsidiaries as of December 31, 2012, were considered to be permanently reinvested. A determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

As at December 31, 2012, the Company had operating loss carryforwards of $213.1 million (December 31, 2011 – $361.6 million) and capital losses of $35.9 million (December 31, 2011 – $13.7 million) before valuation allowance. Of these operating loss carryforwards and capital losses, $215.2 million (December 31, 2011 – $339.8 million) were losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the operating loss carryforwards expire between 2014 and 2032 and the capital losses expire between 2013 and 2017, while certain other jurisdictions allow operating losses to be carried forward indefinitely.

The valuation allowance increased by $3.4 million during the year ended December 31, 2012. The change in the valuation allowance primarily related to 2012 losses in Brazil, Peru and the U.S. The Company continues to incur losses in the U.S., Peru, Brazil, Canada, Luxembourg and certain Argentina entities, which were only partially offset by adjustments for true up amounts to tax return actuals as well as the de-recognition of losses in Barbados upon the completion of a reorganization. The losses are fully offset by a valuation allowance as their recognition does not meet the "more likely than not" threshold.

As at December 31, 2012, the total amount of Gran Tierra's unrecognized tax benefit was approximately $21.8 million (December 31, 2011 – $20.5 million; December 31, 2010 – $4.2 million), a portion of 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. As at December 31, 2012, the amount of interest and penalties on the unrecognized tax benefit included in current income tax liabilities in the consolidated balance sheet was approximately $3.6 million (December 31, 2011 – $1.6 million). The Company had no other material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2012, respectively.

Changes in the Company's unrecognized tax benefit are as follows:

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2012**	2011
Unrecognized tax benefit, beginning of year	**$ 20,500**	$ 4,175
Changes for positions relating to prior year	**1,300**	585
Additions to tax position related to the current year	**—**	15,740
Unrecognized tax benefit, end of year	**$ 21,800**	$ 20,500

The Company and its subsidiaries file income tax returns in the U.S. and certain other foreign jurisdictions. The Company is potentially subject to income tax examinations for the tax years 2005 through 2012 in certain jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefit disclosed above within the next twelve months.

The other gain for the year ended December 31, 2012, of $9.3 million represented a value added tax recovery which occurred upon the completion of a reorganization of subsidiary companies and their Colombian branches in the Colombian reporting segment during the fourth quarter of 2012.

Equity tax for the year ended December 31, 2011, of $8.3 million represented a Colombian tax of 6% on a legislated measure and was 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. The equity tax liability at December 31, 2012, and December 31, 2011, was also partially related to an equity tax liability assumed upon the acquisition of Petrolifera.

10. Accounts Payable and Accrued Liabilities

	As at December 31,	
(Thousands of U.S. Dollars)	**2012**	2011
Trade	**$ 103,720**	$ 71,384
Royalties	**17,607**	37,936
VAT and withholding tax	**28,169**	24,962
Other	**19,185**	14,739
	$ 168,681	$ 149,021

11. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancellable lease terms in excess of one year as of December 31, 2012:

						Year ending December 31	
(Thousands of U.S. Dollars)	**Total**	2013	2014	2015	2016	2017	Thereafter
Oil transportation services	**$ 28,354**	$ 5,077	$ 3,405	$ 3,405	$ 3,405	$ 3,405	$ 9,657
Drilling and G&G	**40,524**	38,171	2,353	—	—	—	—
Completions	**26,188**	14,699	7,368	4,121	—	—	—
Facility construction	**18,484**	11,623	6,861	—	—	—	—
Operating leases	**4,115**	1,928	1,706	477	4	—	—
Software and telecommunication	**1,744**	1,538	74	9	123	—	—
Consulting	**1,592**	1,592	—	—	—	—	—
	$ 121,001	$ 74,628	$ 21,767	$ 8,012	$ 3,532	$ 3,405	$ 9,657

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for the year ended December 31, 2012, was $2.7 million (year ended December 31, 2011 – $3.0 million; year ended December 31, 2010 – $2.3 million).

Indemnities

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

Letters of credit

At December 31, 2012, the Company had provided promissory notes totaling $34.2 million (December 31, 2011 – $20.7 million) as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contingencies

Ecopetrol and Gran Tierra Energy Colombia, Ltd. ("Gran Tierra Colombia"), 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. There is a material difference in the interpretation of the procedure established in Clause 3.5 of Attachment-B of the Guayuyaco Association Contract. Ecopetrol interprets the contract to provide that the extended test production up to a value equal to 30% of the direct exploration costs of the wells is for Ecopetrol's account only and serves as reimbursement of its 30% back-in to the Guayuyaco discovery. Gran Tierra Colombia's contention is that this amount is merely the recovery of 30% of the direct exploration costs of the wells and not exclusively for the benefit of Ecopetrol. There has been no agreement between the parties, and Ecopetrol has filed a lawsuit in the Contravention Administrative Court in the District of Cauca regarding this matter. Gran Tierra Colombia filed a response on April 29, 2008, in which it refuted all of Ecopetrol's claims and requested a change of venue to the courts in Bogota. At this time, no amount has been accrued in the financial statements as the Company does not consider it probable that a loss will be incurred. Ecopetrol is claiming damages of approximately $5.9 million.

Gran Tierra's production from the Costayaco field is subject to an additional royalty that applies when cumulative gross production from a commercial field is greater than five million barrels. This additional royalty is calculated on the difference between a trigger price defined by the Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") and the sales price. The ANH has requested that the additional compensation be paid with respect to production from wells relating to the Moqueta discovery and has initiated a non-compliance procedure under the Chaza Contract. The Moqueta discovery is not located in the Costayaco Exploitation Area. Further, Gran Tierra views the Costayaco field and the Moqueta discovery as two clearly separate and independent hydrocarbon accumulations. Therefore, it is Gran Tierra's view that it is clear that, pursuant to the Chaza Contract, the additional compensation payments are only to be paid with respect to production from the Moqueta wells when the accumulated oil production from any new Exploitation Area created with respect to the Moqueta discovery exceeds five million barrels. Discussions with the ANH have not resolved this issue and Gran Tierra has initiated the dispute resolution process and filed an arbitration claim. As at December 31, 2012, total cumulative production from the Moqueta field was 0.9 MMbbl. The estimated compensation which would be payable on cumulative production to date if the ANH's interpretation is successful is $15.1 million. At this time no amount has been accrued in the financial statements nor deducted from the Company's reserves as Gran Tierra does not consider it probable that a loss will be incurred.

Additionally, the ANH and Gran Tierra Colombia are engaged in discussions regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the additional royalty. Discussions with the ANH are ongoing. As at December 31, 2012, the estimated compensation which would be payable if the ANH's interpretation is successful is $11.6 million. 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.

Gran Tierra is subject to a third party 10% net profits interest on 50% of Gran Tierra's production from the Chaza Block that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There was a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party agreed to resolve this issue through arbitration. The arbitration was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. Gran Tierra received the arbitrator's decision on May 24, 2012. The arbitrator ruled against Gran Tierra and as a result $10.9 million became payable in relation to past production and was recorded as a revenue reduction in 2012. The arbitrator's decision will also increase future net profit interests payable to this third party, but is not expected to have a material impact on future results.

Gran Tierra has several lawsuits and claims pending. Although the outcome of these 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.

12. Financial Instruments, Fair Value Measurements and Credit Risk

At December 31, 2012, the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable and accrued liabilities and contingent consideration included in other long-term liabilities. The fair value of long-term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. Contingent consideration, which relates to the acquisition of the remaining 30% working interest in certain properties in Brazil (Note 3), was recorded on the balance sheet at the acquisition date fair value 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 was determined at the time of measurement in accordance with accepted valuation methods. The fair value of the contingent consideration is being remeasured at the estimated fair value at each reporting period with the change in fair value recognized as income or expense in operating income (Note 3). The fair values of other financial instruments approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2011, the Company did not have any financial assets or liabilities measured at fair value on the balance sheet. At December 31, 2012 and December 31, 2011, the Company held no derivative instruments. The Company does not use derivative financial instruments for speculative purposes.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. The fair value of the contingent consideration payable in connection with the Brazil acquisition at December 31, 2012 was determined using Level 3 inputs (Note 3). The disclosure in the paragraph above regarding the fair value of other financial instruments is based on Level 1 inputs.

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

At December 31, 2012, 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 governments and financial institutions with strong investment grade ratings, or the equivalent in the Company's operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in the Company's operating areas.

Most of the Company's accounts receivable relate to uncollateralized sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. For the year ended December 31, 2012, the Company had one significant customer for its Colombian oil, Ecopetrol. In Argentina, the Company had two significant customers, Shell C.A.P.S.A. and Refineria del Norte S.A. .

For the year ended December 31, 2012, 84% (year ended December 31, 2011 – 91%, year ended December 31, 2010 – 96%) of our revenue and other income was generated in Colombia.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's current and deferred tax liabilities, monetary liabilities, which are mainly denominated in the local currency of the Colombian foreign 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 $105,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The Argentina government has imposed a number of monetary and currency exchange control measures that include restrictions on the free disposition of funds deposited with banks and tight restrictions on transferring funds abroad, with certain exceptions for transfers related to foreign trade and other authorized transactions approved by the Argentina Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for Gran Tierra's Argentina subsidiaries to make payments. At December 31, 2012, $16.4 million, or 8%, of our cash and cash equivalents was deposited with banks in Argentina. We expect to use to these funds for the work program and operations of Argentina in 2013.

13. Credit Facilities

Effective July 30, 2010, a subsidiary of Gran Tierra, Solana, established a credit facility with BNP Paribas for a three-year term which may be extended or amended by agreement between the parties. This reserve-based facility has a maximum borrowing base up to $100 million and was supported by the present value of the petroleum reserves of two of the Company's subsidiaries with operating branches in Colombia, Gran Tierra Colombia and Petrolifera Petroleum Exploration (Colombia) Ltd., and the Company's subsidiary in Brazil – Gran Tierra Energy Brasil Ltda. The initial committed borrowing base was $20 million. Effective August 2, 2012, the committed borrowing base was increased to $50 million. Effective February 15, 2013, the borrowing base was increased to $100 million. Amounts drawn down under the facility bear interest at the U.S. dollar LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.5% per annum is charged on the unutilized balance of the committed borrowing base and is included in G&A expenses. Under the terms of the facility, the Company is required to maintain and was in compliance with certain financial and operating covenants. As at December 31, 2012, and December 31, 2011, the Company had not drawn down any amounts under this facility. On May 17, 2012, BNP Paribas sold Solana's credit facility to Wells Fargo Bank National Association, as part of the sale of its North American reserve-based lending business, without any modification to the facility. Under the terms of the credit facility, the Company cannot pay any dividends to its shareholders if it is in default under the facility, and if the Company is not in default then it is required to obtain bank approval for any dividend payments exceeding $2 million in any fiscal year.

14. Related Party Transactions

On January 12, 2011, the Company entered into an agreement to sublease office space to a company of which Gran Tierra's President and Chief Executive Officer serves as an independent director. The term of the sublease was from February 1, 2011 to January 30, 2013, and the sublease payment was $4,500 per month plus approximately $4,700 of operating and other expense; however, subsequent to September 30, 2012, the sublease was modified to terminate October 31, 2012, so that Gran Tierra can use this office space.

On August 7, 2012, Gran Tierra entered into a contract related to the Brazil drilling program with a company for which one of Gran Tierra's directors is a shareholder and director. During the year ended December 31, 2012, $1.7 million was incurred and capitalized under this contract and at December 31, 2012, $1.1 million was included in accounts payable relating to this contract. Similarly, on August 3, 2010, Gran Tierra entered into a contract related to the Peru drilling program with the same company and $2.8 million was incurred and capitalized under this contract during the year ended December 31, 2011, and at December 31, 2011, $nil was included in accounts payable relating to this contract.

On February 1, 2009, the Company entered into a sublease for office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease ran from February 1, 2009 to August 31, 2011 and the sublease payment was $8,000 per month plus approximately $4,700 for operating and other expenses.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

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

A. Reserve Quantity Information

Gran Tierra's net proved reserves and changes in those reserves for operations are disclosed below. The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and 100% of the reserves have been evaluated by independent qualified reserves consultants, GLJ Petroleum Consultants.

Estimates of crude oil and natural gas proved reserves are determined through analysis of geological and engineering data, and demonstrate reasonable certainty that they are recoverable from known reservoirs under economic and operating conditions that existed at year end.

The determination of oil and natural gas reserves is complex and highly interpretive. Assumptions used to estimate reserve information may significantly increase or decrease such reserves in future periods. The estimates of reserves are subject to continuing changes and, therefore, an accurate determination of reserves may not be possible for many years because of the time needed for development, drilling, testing, and studies of reservoirs. See Critical Accounting Estimates in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" for a description of Gran Tierra's reserves estimation process.

PROVED RESERVES NET OF ROYALTIES [1]

	Colombia		Argentina		Brazil		Total	
	Liquids [3] (Mbbl)	Gas (MMcf)	Liquids [3] (Mbbl)	Gas (MMcf)	Liquids [3] (Mbbl)	Gas (MMcf)	Liquids [3] (Mbbl)	Gas (MMcf)
Proved developed and undeveloped reserves, December 31, 2009	20,791	1,113	1,291	756	—	—	22,082	1,869
Extensions and discoveries	3,107	—	43	—	—	—	3,150	—
Purchases of reserves in place	—	—	—	—	—	—	—	—
Production	(4,945)	(269)	(284)	—	—	—	(5,229)	(269)
Revisions of previous estimates	3,532	388	62	(756)	—	—	3,594	(368)
Proved developed and undeveloped reserves, December 31, 2010	22,485	1,232	1,112	—	—	—	23,597	1,232
Extensions and discoveries	4,009	—	47	—	—	—	4,056	—
Purchases of reserves in place	238	13,797	4,639	4,825	396	—	5,273	18,622
Production	(5,349)	(268)	(727)	(1,143)	(43)	—	(6,119)	(1,411)
Revisions of previous estimates	4,042	(121)	72	—	—	—	4,114	(121)
Proved developed and undeveloped reserves, December 31, 2011	**25,425**	**14,640**	**5,143**	**3,682**	**353**	—	**30,921**	**18,322**
Extensions and discoveries	**4,680**	**921**	**1,731**	**56**	**1,006**	—	**7,417**	**977**
Purchases of reserves in place	—	—		—	**222**	—	**222**	—
Production	**(5,200)**	**(138)**	**(1,049)**	**(1,346)**	**(107)**	—	**(6,356)**	**(1,484)**
Revisions of previous estimates	**6,204**	**(5,951)**	**(32)**	**912**	**117**	—	**6,289**	**(5,039)**
Proved developed and undeveloped reserves, December 31, 2012	**31,109**	**9,472**	**5,793**	**3,304**	**1,591**	—	**38,493**	**12,776**
Proved developed reserves, December 31, 2010 [2]	18,528	1,232	940	—	—	—	19,468	1,232
Proved developed reserves, December 31, 2011 [2]	20,899	13,927	1,918	3,351	54	—	22,871	17,278
Proved developed reserves, December 31, 2012 [2]	**24,677**	**8,551**	**2,459**	**2,777**	**347**	—	**27,483**	**11,328**
Proved undeveloped reserves, December 31, 2010	3,957	—	172	—	—	—	4,129	—
Proved undeveloped reserves, December 31, 2011	4,526	713	3,225	331	299	—	8,050	1,044
Proved undeveloped reserves, December 31, 2012	**6,432**	**921**	**3,334**	**527**	**1,244**	—	**11,010**	**1,448**

(1) Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and NGLs that geological and engineering data demonstrate with reasonable certainty can be recovered in future years from known reservoirs under existing economic and operating conditions. Reserves are considered "proved" if they can be produced economically, as demonstrated by either actual production or conclusive formation testing.

(2) Proved developed oil and gas reserves are expected to be recovered through existing wells with existing equipment and operating methods.

(3) Liquids include oil and NGLs. We have NGL reserves in small amounts in Colombia and Argentina only. Brazil liquids reserves are 100% oil.

B. Capitalized Costs

	Proved Properties	Unproved Properties	Accumulated depletion, depreciation and impairment	Capitalized Costs
Colombia	$ 969,291	$ 274,777	$ (429,526)	$ 814,542
Argentina	159,958	56,975	(89,692	127,241
Brazil	10,836	52,440	(1,884)	61,392
Peru	—	33,675	—	33,675
Balance, December 31, 2011	$ 1,140,085	$ 417,867	$ (521,102)	$ 1,036,850
Colombia	$ 1,219,640	$ 175,871	$ (558,423)	$ 837,088
Argentina	215,030	42,284	(120,649)	136,665
Brazil	84,807	70,129	(28,158)	126,778
Peru	—	96,130		96,130
Balance, December 31, 2012	**$ 1,519,477**	**$ 384,414**	**$ (707,230)**	**$ 1,196,661**

C. Costs Incurred

	Colombia	Argentina	Brazil	Total
Balance, December 31, 2009	$ 837,367	$ 40,191	$ —	$ 877,558
Property acquisition costs				
Proved	—	—	—	—
Unproved	—	—	—	—
Exploration costs	63,115	26,404	—	89,519
Development costs	41,057	7,248	—	48,305
Balance, December 31, 2010	941,539	73,843	—	1,015,382
Property acquisition costs				
Proved	—	58,458	4,601	63,059
Unproved	114,993	49,784	35,285	200,062
Exploration costs	54,486	11,270	17,225	82,981
Development costs	133,121	23,749	5,923	162,793
Balance, December 31, 2011	1,244,139	217,104	63,034	1,524,277
Property acquisition costs				
Proved	24,403	—	24,106	48,509
Unproved	—	—	37,309	37,309
Exploration costs	32,472	1,310	19,128	52,910
Development costs	95,415	38,044	10,297	143,756
Balance, December 31, 2012	**$ 1,396,429**	**$ 256,458**	**$ 153,874**	**$ 1,806,761**

D. Results of Operations for Oil and Gas Producing Activities

	Colombia	Argentina	Brazil	Total
Year Ended December 31, 2010				
Oil and natural gas sales	$ 359,302	$ 13,984	$ —	$ 373,286
Production costs	(50,431)	(8,808)	—	(59,239)
Exploration expenses	—	—	—	—
DD&A expenses	(132,050)	(29,426)	—	(161,476)
Income tax expense	(51,047)	(5,687)	—	(56,734)
Results of Operations	125,774	(29,937)	—	95,837
Year Ended December 31, 2011				
Oil and natural gas sales	543,999	48,016	4,176	596,191
Production costs	(58,081)	(27,076)	(1,018)	(86,175)
Exploration expenses	—	—	—	—
DD&A expenses	(141,133)	(45,506)	(1,819)	(188,458)
Income tax expense	(114,255)	5,489	—	(108,766)
Results of Operations	230,530	(19,077)	1,339	212,792
Year Ended December 31, 2012				
Oil and natural gas sales	**493,615**	**79,642**	**9,852**	**583,109**
Production costs	**(87,410)**	**(32,696)**	**(4,637)**	**(124,743)**
Exploration expenses	—	—	—	—
DD&A expenses	**(122,055)**	**(31,466)**	**(26,300)**	**(179,821)**
Income tax expense	**(95,042)**	**(1,412)**	—	**(96,454)**
Results of Operations	**$ 189,108**	**$ 14,068**	**$ (21,085)**	**$ 182,091**

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

The following disclosure is based on estimates of net proved reserves and the period during which they are expected to be produced. Future cash inflows are computed by applying the twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions to Gran Tierra's after royalty share of estimated annual future production from proved oil and gas reserves. The 2012 twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within that twelve month period was $103.57 (2011 – $95.20; 2010 – $71.50) for Colombia, $66.12 (2011 – $54.26; 2010 – $50.18) for Argentina and $95.38 (2011 – $97.07; 2010 – $nil) for Brazil. The calculated weighted average production costs at December 31, 2012, were $18.49 (2011 – $10.10; 2010 – $10.48) for Colombia, $22.99 (2011 – $28.50; 2010 – $18.87) for Argentina and $5.71 (2011 – $15.65; 2010 – $nil) for Brazil. Future development and production costs to be incurred in producing and further developing the proved reserves are based on year end cost indicators.

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

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

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

	Colombia	Argentina	Brazil	Total
December 31, 2010				
Future cash inflows	1,621,461	55,833	—	1,677,294
Future production costs	(373,467)	(27,314)	—	(400,781)
Future development costs	(136,688)	(4,965)	—	(141,653)
Future asset retirement obligations	(8,070)	(385)	—	(8,455)
Future income tax expense	(295,146)	—	—	(295,146)
Future net cash flows	808,090	23,169	—	831,259
10% discount	(225,990)	(4,270)	—	(230,260)
Standardized Measure of Discounted Future Net Cash Flows	582,100	18,899	—	600,999
December 31, 2011				
Future cash inflows	2,535,662	331,554	34,244	2,901,460
Future production costs	(459,955)	(179,277)	(11,667)	(650,899)
Future development costs	(145,513)	(50,742)	(4,900)	(201,155)
Future asset retirement obligations	(12,420)	(3,063)	(525)	(16,008)
Future income tax expense	(500,700)	(18,207)	(1,215)	(520,122)
Future net cash flows	1,417,074	80,265	15,937	1,513,276
10% discount	(369,112)	(26,274)	(2,543)	(397,929)
Standardized Measure of Discounted Future Net Cash Flows	1,047,962	53,991	13,394	1,115,347
December 31, 2012				
Future cash inflows	**3,283,618**	**423,867**	**151,726**	**3,859,211**
Future production costs	**(915,035)**	**(193,434)**	**(17,758)**	**(1,126,227)**
Future development costs	**(204,658)**	**(61,165)**	**(27,550)**	**(293,373)**
Future asset retirement obligations	**(13,360)**	**(3,681)**	**(1,750)**	**(18,791)**
Future income tax expense	**(584,762)**	**(44,023)**	**—**	**(628,785)**
Future net cash flows	**1,565,803**	**121,564**	**104,668**	**1,792,035**
10% discount	**(428,616)**	**(36,006)**	**(29,961)**	**(494,583)**
Standardized Measure of Discounted Future Net Cash Flows	**1,137,187**	**85,558**	**74,707**	**1,297,452**

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	2012	2011	2010
Balance, December 31, 2011	1,115,347	$ 600,999	$ 406,384
Sales and transfers of oil and gas produced, net of production costs	(457,095)	(491,046)	(313,840)
Net changes in prices and production costs related to future production	162,623	446,111	208,649
Extensions, discoveries and improved recovery, less related costs	342,906	206,762	32,194
Previously estimated development costs incurred during the year	90,801	106,291	107,856
Revisions of previous quantity estimates	286,995	242,761	140,893
Accretion of discount	149,850	81,422	58,043
Purchases of reserves in place	10,422	93,071	—
Sales of reserves in place	—	—	—
Net change in income taxes	(198,808)	(148,529)	(39,180)
Changes in future development costs	(205,589)	(22,495)	—
Net increase	182,105	514,348	194,615
Balance, December 31, 2012	1,297,452	1,115,347	600,999

2) Summarized Quarterly Financial Information

	Revenue and other Income	Expenses	Income before income taxes	Income taxes	Net (loss) income	Net (loss) income per share – basic	Net (loss) income per share – diluted
2012							
First quarter	155,951	125,128	30,823	(31,136)	(313)	0.00	0.00
Second quarter	115,150	82,310	32,840	(19,736)	13,104	0.05	0.05
Third quarter	168,933	92,920	76,013	(31,408)	44,605	0.16	0.16
Fourth quarter	145,153	87,466	57,687	(15,424)	42,263	0.15	0.15
	585,187	387,824	197,363	(97,704)	99,659	0.35	0.35
2011							
First quarter	122,519	82,110	40,409	(26,696)	13,713	0.05	0.05
Second quarter	162,120	102,560	59,560	(27,993)	31,567	0.11	0.11
Third quarter	151,033	71,974	79,059	(29,974)	49,085	0.18	0.17
Fourth quarter	161,735	106,516	55,219	(22,667)	32,552	0.12	0.12
	597,407	363,160	234,247	(107,330)	126,917	0.46	0.45

In March 2011, we acquired Petrolifera Petroleum Limited.

Appendix A — Statement of Reserves Data and Other Oil and Gas Information

Effective December 31, 2012 — Prepared on February 25, 2013

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Abbreviations and Conversion

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	Mcf/d	thousand cubic feet per day
bbl/d	barrels per day	Bcf	billion cubic feet
NGLs	natural gas liquids	M$	thousands of US dollars
BOE/d	barrels of oil equivalent per day		

API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
BOE	barrel of oil equivalent on the basis of 1 BOE to 6 Mcf of natural gas. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 1 BOE for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
$000s	thousands of dollars
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade

Notes and Definitions

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

The following terms, used in the preparation of the GLJ Report (defined herein) and this document have the following meanings:

"Associated gas" means the gas cap overlying a crude oil accumulation in a reservoir.

"Corporation" means Gran Tierra Energy Inc.

"Crude oil" or **"Oil"** means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"Developed Producing" reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"Developed Non-Producing" reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"Development well" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews

and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");
(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;
(c) dry hole contributions and bottom hole contributions;
(d) costs of drilling and equipping exploratory wells; and
(e) costs of drilling exploratory type stratigraphic test wells.

"Exploratory well" means a well that is not a development well, a service well or a stratigraphic test well.

"Field" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "play" or "area of interest".

"Future prices and costs" means future prices and costs that are:
(a) generally accepted as being a reasonable outlook of the future;
(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Corporation issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"Future income tax expenses" means future income tax expenses estimated (generally, year-by-year):
(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;
(b) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"Future net revenue" means the estimated net amount to be received with respect to the development and production of reserves estimated using forecast prices and costs.

"Gross" means:
(a) in relation to the Corporation's interest in production or reserves, its "Corporation gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Corporation;
(b) in relation to wells, the total number of wells in which the Corporation has an interest, and
(c) in relation to properties, the total area of properties in which the Corporation has an interest.

"Natural gas" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"Natural gas liquids" or **"NGL"** means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"Net" means
(a) in relation to the Corporation's interest in production or reserves its working interest (operating or non operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;
(b) in relation to the Corporation's interest in wells, the number of wells obtained by aggregating the Corporation's working interest in each of its gross wells; and
(c) in relation to the Corporation's interest in a property, the total area in which the Corporation has an interest multiplied by the working interest owned by the Corporation.

"Non-associated gas" means an accumulation of natural gas in a reservoir where there is no crude oil.

"Operating costs" or **"production costs"** means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"Probable" reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"Production" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"Property" includes:
(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"Property acquisition costs" means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

"Proved property" means a property or part of a property to which reserves have been specifically attributed.

"Reserves" are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically recoverable from discovered resources, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"Reservoir" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"Undeveloped" reserves are those reserves expected to be recovered from know accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable, possible) to which they are assigned. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"Unproved property" means a property or part of a property to which no reserves have been specifically attributed.

"Well abandonment costs" means costs of abandoning a well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

Forward - Looking Statements

Certain statements included in this document constitute forward-looking statements under applicable securities legislation. These statements relate to future events or the Corporation's future performance. All statements other than statements of historical fact are forward-looking statements. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expect", "plan", "anticipate", "believe", "estimate", "predict", "potential", "continue", or the negative of these terms or other comparable terminology.

Forward looking statements or information in this document include, but are not limited to, reserve quantities and the discounted present value of future net cash flows from such reserves, net revenue, future production levels, capital expenditures, exploration plans, development plans, acquisition and disposition plans and the timing thereof, operating and other costs, and royalty rates. These statements are only predictions. Actual events or results may differ materially. In addition, this document may contain forward-looking statements attributed to third party industry sources. Undue reliance should not be placed on these forward-looking statements, as there can be no assurance that the plans, intentions or expectations upon which they are based will occur. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, both general and specific, that contribute to the possibility that the predictions, forecasts, projections and other forward-looking statements will not occur.

In addition to other assumptions identified in this statement, assumptions in respect of forward-looking statements have been made regarding, among other things:

- the Corporation's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- the Corporation's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- sustainability and growth of production and reserves through prudent management and acquisitions;
- the emergence of accretive growth opportunities;
- the impact of Colombian, Argentine and Brazilian governmental regulation on the Corporation;
- the strategy of the Corporation regarding commodity price risk management;

- changes in oil and natural gas prices and the impact of such changes on cash flow;
- the level of capital expenditures devoted to development activity rather than exploration;
- the use of development activity and/or acquisitions to replace and add to reserves;
- the quantity of oil and natural gas reserves and oil and natural gas production levels; and
- currency, exchange and interest rates.

Although the Corporation believes that the expectations reflected in the forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. The Corporation cannot guarantee future results, levels of activity, performance, or achievements. Moreover, neither the Corporation nor any other person assumes responsibility for the accuracy and completeness of the forward-looking statements. Some of the risks and other factors, some of which are beyond the Corporation's control, which could cause results to differ materially from those expressed in the forward-looking statements contained in this document include, but are not limited to:

- general economic conditions globally;
- industry conditions, including fluctuations in the price of crude oil, natural gas and natural gas liquids and services used by the Corporation;
- uncertainties associated with estimating reserves;
- royalties payable in respect of oil and gas production;
- governmental regulation of the oil and gas industry, including income tax and environmental regulation;
- fluctuation in foreign exchange or interest rates;
- stock market volatility and market valuations;
- the impact of environmental events;
- the need to obtain required approvals from regulatory authorities;
- unanticipated operating events which can reduce production or cause production to be shut-in or delayed;
- failure to obtain industry partner and other third party consents and approvals, when required; and
- third party performance of obligations under contractual arrangements.

Statements relating to "reserves" are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing list of factors is not exhaustive. The forward-looking statements contained in this document are expressly qualified by this cautionary statement. Subject to the Corporation's obligations under applicable securities laws, the Corporation is not under any duty to update any of the forward-looking statements after the date of this document to conform such statements to actual results or to changes in the Corporation's expectations.

A barrel of oil equivalent (BOE), derived by converting gas to oil in the ratio of six thousand cubic feet of gas to one barrel of oil, may be misleading, particularly if used in isolation. A BOE conversion is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the estimates of future net revenues presented in the following tables represent the fair market value of the Corporation's reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Report will be attained and variances could be material. Other assumptions and qualifications relating to costs and other matters are included in the GLJ Report. The recovery and reserves estimates of the Corporation's properties described herein are estimates only. The actual reserves on the Corporation's properties may be greater or less than those calculated.

Part 1 – Date of Statement

Item 1.1 Relevant Dates

GLJ Petroleum Consultants Ltd. ("GLJ") was engaged by the Corporation to conduct a valuation of the Corporation's reserves in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("NI 51-101"). GLJ prepared a report dated February 4, 2013, evaluating the Corporation's oil, NGL and natural gas reserves in Colombia, Argentina and Brazil as of December 31, 2012, referred to as the "GLJ Report".

The tables contained in this Statement are a summary of the oil, NGL and natural gas reserves of the Corporation and the net present value of future net revenue attributable to such reserves as evaluated in the GLJ Report based on forecast price and cost assumptions. The tables summarize the data contained in the GLJ Report and as a result may contain slightly different numbers than such reports due to rounding. Also due to rounding, certain columns may not add exactly.

The Corporation's properties with assigned reserves are located in Argentina, Brazil and Colombia. In addition the Corporation has interests in exploration properties in Peru.

All monetary values are expressed in U.S. dollars.

Part 2 – Disclosure of Reserves Data

Item 2.1.1 Reserves Data (Forecast Prices and Costs)

Consolidated Oil And Gas Reserves at December 31, 2012
Based on Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved Developed Producing	35,136	26,789	0	0	11,572	10,515	106	103
Proved Developed Non-Producing	509	444	0	0	1,014	812	1	0
Proved Undeveloped	13,967	10,891	0	0	1,483	1,327	29	29
Total Proved	49,612	38,124	0	0	14,069	12,654	136	132
Total Probable	19,475	14,954	0	0	6,480	5,550	53	52
Total Proved Plus Probable	69,087	53,078	0	0	20,549	18,204	189	184
Total Possible	28,245	21,648	0	0	59,086	51,529	510	457
Total Proved Plus Probable Plus Possible	97,332	74,726	0	0	79,635	69,733	699	641

Colombia Properties at December 31, 2012
Oil and Gas Reserves Based on Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved Developed Producing	32,403	24,405	0	0	8,371	7,757	34	31
Proved Developed Non-Producing	112	96	0	0	993	794	0	0
Proved Undeveloped	8,805	6,427	0	0	980	892	0	0
Total Proved	41,320	30,928	0	0	10,344	9,443	34	31
Total Probable	14,961	11,051	0	0	4,213	3,621	5	4
Total Proved Plus Probable	56,281	41,977	0	0	14,557	13,064	39	35
Total Possible	19,168	13,813	0	0	5,063	4,102	7	7
Total Proved Plus Probable Plus Possible	75,449	55,792	0	0	19,620	17,166	46	42

Argentina Properties at December 31, 2012
Oil and Gas Reserves Based on Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved Developed Producing	2,334	2,037	0	0	3,201	2,758	72	72
Proved Developed Non-Producing	397	348	0	0	21	18	1	0
Proved Undeveloped	3,739	3,222	0	0	503	435	29	29
Total Proved	6,470	5,607	0	0	3,725	3,211	102	101
Total Probable	2,980	2,567	0	0	2,267	1,929	48	48
Total Proved Plus Probable	9,450	8,174	0	0	5,992	5,140	150	149
Total Possible	6,709	5,770	0	0	54,023	47,427	503	450
Total Proved Plus Probable Plus Possible	16,159	13,944	0	0	60,015	52,567	653	599

Brazil Properties at December 31, 2012
Oil and Gas Reserves Based on Forecast Prices and Costs

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved Developed Producing	399	347	0	0	0	0	0	0
Proved Developed Non-Producing	0	0	0	0	0	0	0	0
Proved Undeveloped	1,423	1,242	0	0	0	0	0	0
Total Proved	1,822	1,589	0	0	0	0	0	0
Total Probable	1,534	1,336	0	0	0	0	0	0
Total Proved Plus Probable	3,356	2,925	0	0	0	0	0	0
Total Possible	2,368	2,065	0	0	0	0	0	0
Total Proved Plus Probable Plus Possible	5,724	4,990	0	0	0	0	0	0

Gross = working interest before royalties
Net = working interest after royalties

All monetary values are expressed in U.S. dollars.

Item 2.1.2 Net Present Value of Future Net Revenue (Forecast Case)

Consolidated Properties at December 31, 2012
Net Present Values of Future Net Revenue Based on Forecast Prices and Costs

	Before Deducting Income Taxes Discounted at					After Deducting Income Taxes Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed	1,622,417	1,392,927	1,227,829	1,103,243	1,005,681	1,229,002	1,057,278	932,062	836,638	761,395
Proved Undeveloped	523,287	421,652	347,928	292,462	249,471	371,208	293,524	237,196	194,937	162,330
Total Proved	2,145,704	1,814,579	1,575,757	1,395,705	1,255,152	1,600,210	1,350,802	1,169,258	1,031,575	923,725
Total Probable	995,629	772,554	622,370	515,462	436,077	685,775	529,796	425,461	351,531	296,820
Total Proved Plus Probable	3,141,333	2,587,133	2,198,127	1,911,167	1,691,229	2,285,985	1,880,598	1,594,719	1,383,106	1,220,545
Total Possible	1,601,233	1,142,005	856,365	666,979	535,062	1,062,741	746,079	550,433	421,691	332,752
Total Proved Plus Probable Plus Possible	4,742,566	3,729,138	3,054,492	2,578,146	2,226,291	3,348,726	2,626,677	2,145,152	1,804,797	1,553,297

Colombia Properties at December 31, 2012
Net Present Values of Future Net Revenue Based on Forecast Prices and Costs

	Before Deducting Income Taxes Discounted at					After Deducting Income Taxes Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed	1,523,903	1,302,936	1,144,748	1,025,869	933,097	1,145,293	980,902	861,605	771,049	699,880
Proved Undeveloped	360,857	292,437	243,038	205,983	177,301	241,073	192,413	157,066	130,505	109,971
Total Proved	1,884,760	1,595,373	1,387,786	1,231,852	1,110,398	1,386,366	1,173,315	1,018,671	901,554	809,851
Total Probable	797,286	620,723	500,957	415,209	351,226	535,086	415,508	334,489	276,526	233,300
Total Proved Plus Probable	2,682,046	2,216,096	1,888,743	1,647,061	1,461,624	1,921,452	1,588,823	1,353,160	1,178,080	1,043,151
Total Possible	994,664	702,648	523,732	406,219	324,852	666,847	468,342	346,787	267,069	212,007
Total Proved Plus Probable Plus Possible	3,676,710	2,918,744	2,412,475	2,053,280	1,786,476	2,588,299	2,057,165	1,699,947	1,445,149	1,255,158

Argentina Properties at December 31, 2012
Net Present Values of Future Net Revenue Based on Forecast Prices and Costs

	Before Deducting Income Taxes Discounted at					After Deducting Income Taxes Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed	81,820	73,999	67,696	62,519	58,198	67,015	60,384	55,072	50,734	47,129
Proved Undeveloped	89,981	70,856	56,598	45,697	37,183	57,686	42,752	31,838	23,650	17,372
Total Proved	171,801	144,855	124,294	108,216	95,381	124,701	103,136	86,910	74,384	64,501
Total Probable	87,177	67,340	53,166	42,805	35,076	54,641	41,171	31,666	24,810	19,765
Total Proved Plus Probable	258,978	212,195	177,460	151,021	130,457	179,342	144,307	118,576	99,194	84,266
Total Possible	429,418	310,778	232,452	178,817	140,883	278,890	195,544	141,178	104,435	78,815
Total Proved Plus Probable Plus Possible	688,396	522,973	409,912	329,838	271,340	458,232	339,851	259,754	203,629	163,081

Brazil Properties at December 31, 2012
Net Present Values of Future Net Revenue Based on Forecast Prices and Costs

	Before Deducting Income Taxes Discounted at					After Deducting Income Taxes Discounted at				
	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Developed	16,694	15,992	15,385	14,855	14,386	16,694	15,992	15,385	14,855	14,386
Proved Undeveloped	72,449	58,359	48,292	40,782	34,987	72,449	58,359	48,292	40,782	34,987
Total Proved	89,143	74,351	63,677	55,637	49,373	89,143	74,351	63,677	55,637	49,373
Total Probable	111,166	84,491	68,247	57,448	49,775	96,048	73,117	59,306	50,195	43,755
Total Proved Plus Probable	200,309	158,842	131,924	113,085	99,148	185,191	147,468	122,983	105,832	93,128
Total Possible	177,151	128,579	100,181	81,943	69,327	117,004	82,193	62,468	50,187	41,930
Total Proved Plus Probable Plus Possible	377,460	287,421	232,105	195,028	168,475	302,195	229,661	185,451	156,019	135,058

All monetary values are expressed in U.S. dollars.

Item 2.1.3 Additional Information Concerning Future Net Revenue (Forecast Case)

Consolidated Properties at December 31, 2012
Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs

	Revenue (M$)	Other (Income)/Exp (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs (M$)	Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Net Revenue After Income Taxes (M$)
Total Proved	4,766,952	(278)	1,119,540	1,181,124	297,029	23,277	2,145,703	545,494	1,600,209
Total Proved Plus Probable	6,619,238	(278)	1,555,629	1,541,506	355,046	25,445	3,141,334	855,348	2,285,986
Total Proved Plus Probable Plus Possible	9,553,832	2,843	2,218,706	2,042,667	524,819	27,917	4,742,566	1,393,841	3,348,725

Colombia Properties at December 31, 2012
Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs

	Revenue (M$)	Other (Income)/Exp (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs (M$)	Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Net Revenue After Income Taxes (M$)
Total Proved	4,097,448	4,722	1,031,635	961,853	206,836	17,087	1,884,759	498,394	1,386,365
Total Proved Plus Probable	5,560,470	4,722	1,415,253	1,216,654	233,026	18,213	2,682,046	760,594	1,921,452
Total Proved Plus Probable Plus Possible	7,440,813	4,722	1,939,068	1,479,912	330,799	19,047	3,676,709	1,088,412	2,588,297

Argentina Properties at December 31, 2012
Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs

	Revenue (M$)	Other (Income)/Exp (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs (M$)	Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Net Revenue After Income Taxes (M$)
Total Proved	509,660	(5,000)	67,400	198,882	62,346	4,230	171,802	47,100	124,702
Total Proved Plus Probable	760,645	(5,000)	102,102	295,217	94,173	5,173	258,980	79,636	179,344
Total Proved Plus Probable Plus Possible	1,599,158	(1,879)	213,704	522,356	166,173	6,648	688,398	230,164	458,234

Brazil Properties at December 31, 2012
Total Future Net Revenue (Undiscounted) Based on Forecast Prices and Costs

	Revenue (M$)	Other (Income)/Exp (M$)	Royalties (M$)	Operating Costs (M$)	Development Costs (M$)	Abandonment and Reclamation Costs (M$)	Net Revenue Before Income Taxes (M$)	Income Taxes (M$)	Net Revenue After Income Taxes (M$)
Total Proved	159,844	0	20,505	20,389	27,847	1,961	89,142	0	89,142
Total Proved Plus Probable	298,123	0	38,274	29,635	27,847	2,059	200,308	15,118	185,190
Total Proved Plus Probable Plus Possible	513,862	0	65,934	40,400	27,847	2,222	377,459	75,265	302,194

All monetary values are expressed in U.S. dollars.

Item 2.1.3 Additional Information Concerning Future Net Revenue Continued (Forecast Case)

Colombia Properties at December 31, 2012
Future Net Revenue by Production Group Based on Forecast Prices and Costs

		Net Present Value of Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
Reserves Category	Production Group	(M$)	$/bbl	$/Mcf
Total Proved	Light & Medium Oil +NGL's	1,383,391	44.52	7.42
	Natural Gas	4,395	3.02	0.50
		1,387,786	42.66	7.11
Total Proved Plus Probable	Light & Medium Oil +NGL's	1,883,207	44.25	7.37
	Natural Gas	5,536	3.4	0.57
		1,888,743	42.74	7.12
Total Proved Plus Probable Plus Possible	Light & Medium Oil +NGL's	2,405,257	42.36	7.06
	Natural Gas	7,218	3.77	0.63
		2,412,475	41.1	6.85

Argentina Properties at December 31, 2012
Future Net Revenue by Production Group Based on Forecast Prices and Costs

		Net Present Value of Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
Reserves Category	Production Group	(M$)	$/bbl	$/Mcf
Total Proved	Light & Medium Oil +NGL's	121,370	20.99	3.50
	Natural Gas	2,924	6.35	1.06
		124,294	19.91	3.32
Total Proved Plus Probable	Light & Medium Oil +NGL's	172,457	20.44	3.41
	Natural Gas	5,003	6.74	1.12
		177,460	19.33	3.22
Total Proved Plus Probable Plus Possible	Light & Medium Oil +NGL's	352,321	24.40	4.07
	Natural Gas	57,591	6.50	1.08
		409,912	17.59	2.93

Brazil Properties at December 31, 2012
Future Net Revenue by Production Group Based on Forecast Prices and Costs

		Net Present Value of Future Net Revenue Before Income Taxes (Discounted at 10%/Year)		
Reserves Category	Production Group	(M$)	$/bbl	$/Mcf
Total Proved	Light & Medium Oil +NGL's	63,677	40.08	6.68
	Natural Gas	0	0.00	0.00
		63,677		
Total Proved Plus Probable	Light & Medium Oil +NGL's	131,924	45.10	7.52
	Natural Gas	0	0.00	0.00
		131,924		
Total Proved Plus Probable Plus Possible	Light & Medium Oil +NGL's	232,105	46.51	7.75
	Natural Gas	0	0.00	0.00
		232,105		

Part 3 – Pricing Assumptions

Item 3.2 (a) Forecast Prices Used in Estimates

The pricing assumptions used in estimating reserves data disclosed above with respect to net present values of future net revenue (forecast) are set forth below. The forecast inflation rate for price is 2 percent from 2022 onwards and 2% for costs from 2014 onwards. The price forecast for Colombia and Brazil is based off GLJ's standard Brent price forecast effective January 1, 2013. The price forecast for Argentina is based off GLJ's Argentina's local price estimates. GLJ is an independent qualified reserves auditor pursuant to NI 51-101.

		World	Argentina†					Colombia		
	Exchange Rate	Brent Crude Oil	Natural gas Liquids			Gas				
			Neuquen	Condensate	LPG*	Neuquen	Gas Plus	Condensate	CNG** Gas	Magangue
Year	$US/$Cdn	$US/bbl	$US/bbl	$US/bbl	$US/bbl	$US/mmbtu	$US/mmbtu	$US/bbl	$US/mmbtu	$US/mmbtu
2013	1.000	105.00	74.00	80.00	59.00	3.60	4.40	105.00	2.03	4.80
2014	1.000	102.50	75.48	81.60	60.18	3.67	4.49	107.10	2.07	4.90
2015	1.000	102.50	76.99	83.23	61.38	3.75	4.58	109.24	2.11	4.99
2016	1.000	100.00	78.53	84.90	62.61	3.82	4.67	111.43	2.15	5.09
2017	1.000	100.00	80.10	86.59	63.86	3.90	4.76	113.66	2.20	5.20
2018	1.000	100.00	81.70	88.33	65.14	3.97	4.86	115.93	2.24	5.30
2019	1.000	101.35	83.34	90.09	66.44	4.05	4.96	118.25	2.29	5.41
2020	1.000	103.38	85.00	91.89	67.77	4.14	5.05	120.61	2.33	5.51
2021	1.000	105.45	86.70	93.73	69.13	4.22	5.16	123.02	2.38	5.62
2022	1.000	107.55	88.44	95.61	70.51	4.30	5.26	125.48	2.43	5.74
2022+	1.000	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr

†Argentina Prices are before deduction of provincial taxes

Item 3.2 (b) Corporation's weighted average historical prices for the most recent financial year.

The Corporation's weighted average historical prices for the year ended December 31, 2012 were:

	Light & Medium Oil	Natural Gas
Colombia	$103.04	$3.16
Argentina	$71.12	$3.83
Brazil	$97.35	$0.00
Consolidated	$97.31	$3.76

Part 4 – Reconciliation of Changes In Reserves

Item 4.1 Reserves reconciliation

Reconciliation of gross reserves by principal product type based on forecast prices and costs:

Consolidated Properties at December 31, 2012

	Light & Medium Oil			Natural Gas			Natural Gas Liquids		
Gross Reserves	Proved Mbbl	Probable Mbbl	Proved Plus Probable Mbbl	Proved MMcf	Probable MMcf	Proved Plus Probable MMcf	Proved Mbbl	Probable Mbbl	Proved Plus Probable Mbbl
December 31, 2011	39,822	13,183	53,005	20,326	28,286	48,612	158	172	330
Extensions	7,255	3,730	10,985	0	0	0	0	0	0
Improved recoveries	386	(27)	359	0	0	0	0	0	0
Technical Revisions	8,630	44	8,674	(5,573)	(24,931)	(30,504)	11	(119)	(108)
Discoveries	1,589	2,323	3,912	1,044	3,126	4,170	2	1	3
Acquisitions	250	223	473	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic factors	2	(1)	1	0	(1)	(1)	(1)	(1)	(2)
Production	(8,322)	0	(8,322)	(1,728)	0	(1,728)	(34)	0	(34)
December 31, 2012	**49,612**	**19,475**	**69,087**	**14,069**	**6,480**	**20,549**	**136**	**53**	**189**

Based on forecast prices and costs

Colombian Properties at December 31, 2012

	Light & Medium Oil			Natural Gas			Natural Gas Liquids		
Gross Reserves	Proved Mbbl	Probable Mbbl	Proved Plus Probable Mbbl	Proved MMcf	Probable MMcf	Proved Plus Probable MMcf	Proved Mbbl	Probable Mbbl	Proved Plus Probable Mbbl
December 31, 2011	33,452	7,929	41,381	15,956	22,848	38,804	58	95	153
Extensions	4,800	3,375	8,175	0	0	0	0	0	0
Improved recoveries	386	(27)	359	0	0	0	0	0	0
Technical Revisions	8,813	1,418	10,231	(6,433)	(21,740)	(28,173)	(23)	(90)	(113)
Discoveries	913	2,266	3,179	981	3,105	4,086	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic factors	0	0	0	(1)	0	(1)	(1)	0	(1)
Production	(7,047)	0	(7,047)	(159)	0	(159)	0	0	0
December 31, 2012	**41,320**	**14,961**	**56,281**	**10,344**	**4,213**	**14,557**	**34**	**5**	**39**

Based on forecast prices and costs

Argentina Properties at December 31, 2012

	Light & Medium Oil			Natural Gas			Natural Gas Liquids		
Gross Reserves	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	Mbbl	Mbbl	Mbbl	MMcf	MMcf	MMcf	Mbbl	Mbbl	Mbbl
December 31, 2011	5,976	3,932	9,908	4,370	5,438	9,808	100	77	177
Extensions	1,389	326	1,715	0	0	0	0	0	0
Improved recoveries	0	0	0	0	0	0	0	0	0
Technical Revisions	(317)	(1,434)	(1,751)	860	(3,191)	(2,331)	34	(29)	5
Discoveries	576	157	733	63	21	84	2	1	3
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic factors	0	0	0	0	0	0	0	(1)	(1)
Production	(1,153)	0	(1,153)	(1,569)	0	(1,569)	(34)	0	(34)
December 31, 2012	**6,470**	**2,980**	**9,450**	**3,725**	**2,267**	**5,992**	**102**	**48**	**150**

Based on forecast prices and costs

Brazil Properties at December 31, 2012

	Light & Medium Oil			Natural Gas			Natural Gas Liquids		
Gross Reserves	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
	Mbbl	Mbbl	Mbbl	MMcf	MMcf	MMcf	Mbbl	Mbbl	Mbbl
December 31, 2011	394	1,322	1,716	0	0	0	0	0	0
Extensions	1,066	29	1,095	0	0	0	0	0	0
Improved recoveries	0	0	0	0	0	0	0	0	0
Technical Revisions	134	60	194	0	0	0	0	0	0
Discoveries	100	(100)	0	0	0	0	0	0	0
Acquisitions	250	223	473	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic factors	0	0	0	0	0	0	0	0	0
Production	(122)	0	(122)	0	0	0	0	0	0
December 31, 2012	**1,822**	**1,534**	**3,356**	**0**	**0**	**0**	**0**	**0**	**0**

Based on forecast prices and costs

Part 5 – Additional Information Relating to Reserves

Item 5.1 Undeveloped Reserves

Undeveloped reserves were attributed by GLJ in accordance with the standards and procedures contained in the Canadian Oil & Gas Evaluation (COGE) Handbook. Proved and probable reserves have been assigned in accordance with engineering and geological practices as defined under NI51-101. In general, undeveloped reserves are planned to be developed over the next two years. In some cases, it will take longer than two years to develop these reserves. There are a number of factors that could result in delayed or cancelled development, including the following: i) changing economic conditions, ii) changing technical conditions, iii) surface access issues and iv) a larger development program may be needed to be spread out over several years to optimize capital allocation and facility utilization.

Therefore, subject to the success of operations, within the next two years the Corporations proved undeveloped reserves will be developed through further drilling and completion of wells within these areas.

In the table below, "1st Attributed" consists of undeveloped reserves associated with acquisitions plus discoveries, in the year those undeveloped reserves were first attributed, and "Booked Gross" is the Corporation's working interest reserves booked at December 31 for each of the most recent three financial years.

Additional Information Relating to Reserves Data
Corporate

	Light & Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids	
Escalated Prices	1st Attributed Gross (Mbbl)	Booked Gross (Mbbl)	1st Attributed Gross (Mbbl)	Booked Gross (Mbbl)	1st Attributed Gross (MMcf)	Booked Gross (MMcf)	1st Attributed Gross (Mbbl)	Booked Gross (Mbbl)
Proved Undeveloped								
Prior to 2010	1,051	1,051	0	0	0	0	0	0
2010	5,097	5,402	0	0	0	0	0	0
2011	7,883	10,395	0	0	1,159	1,159	27	27
2012	**0**	**13,967**	**0**	**0**	**0**	**1,483**	**0**	**29**
Probable Undeveloped								
Prior to 2010	1,306	1,306						
2010	3,240	3,461	0	0	0	0	0	0
2011	6,501	6,854	0	0	24,212	24,212	135	135
2012	**0**	**10,875**	**0**	**0**	**0**	**5,017**	**0**	**29**

* 'First attributed' refers to reserves at year-end of the corresponding fiscal year

Proved Undeveloped Reserves:

Approximately 27% of proved undeveloped reserves are located in our Puesto Morales field in Argentina. This field was acquired as a result of the Petrolifera acquisition in 2011. Additionally, approximately 22% and 28% of proved undeveloped reserves are in our Moqueta and Costayaco fields in Colombia. None of our proved undeveloped reserves at December 31, 2012, have remained undeveloped for five years or more since initial disclosure as proved reserves and we have adopted a development plan which indicates that the proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure as proved reserves.

In 2012, we converted 44% of the total year-end 2011 proved undeveloped reserves, to developed status. In 2012, we made investments, consisting solely of capital expenditures, of $44.0 million in Colombia and $19.5 million in Argentina associated with the development of proved undeveloped reserves. Approximately 94% of proved undeveloped reserves conversions occurred in the Costayaco and Moqueta fields in Colombia and 3% in the Puesto Morales field in Argentina. The majority of proved undeveloped conversions occurred as a result of ongoing development activities in the Costayaco and Moqueta fields in Colombia, including infill drilling and a pressure maintenance project in the Costayaco field and infill drilling and facilities development in the Moqueta field. The waterflood optimization program for the Sierra Blancas reservoir and the commencement of a horizontal well development program for the Loma Montosa reservoir, both in the Puesto Morales field in Argentina, also converted proved undeveloped reserves to proved developed reserves.

Probable Undeveloped Reserves:

Approximately 22% of the Corporation's probable undeveloped reserves at year-end 2012 are in Argentina and the remaining probable undeveloped reserves are in Colombia (69%) and Brazil (9%).

In Argentina, approximately 81% of the country's probable undeveloped reserves are attributed to the Puesto Morales property, which was added to our acreage through our acquisition of Petrolifera in March of 2011.

Approximately 54% of the probable undeveloped reserves in Colombia are associated with the Moqueta field and 34% are associated with the Ramiriquí field.

In Brazil, all of the probable undeveloped reserves are associated with the Tiê field.

Item 5.2 Significant Factors or Uncertainties

The estimation of reserves requires significant judgment and decisions based on available geological, geophysical, engineering, and economic data. These estimates can change substantially as additional information from ongoing development activities and production performance become available and as economic and political conditions impact oil and gas prices and costs change. The Corporation's estimates are based on current production forecasts, prices and economic conditions. All of the Corporation's reserves are evaluated by GLJ, an independent engineering firm.

As circumstances change and additional data becomes available, reserve estimates also change. Based on new information, reserve estimates are reviewed and revised, either upward or downward, as warranted. Although every reasonable effort was made by the Corporation to ensure that reserve estimates are accurate, revisions arise as new information becomes available. As new geological, production and economic information is incorporated into the process of estimating reserves the accuracy of the reserve estimates improves.

Item 5.3 Future Development Costs

The following table sets forth the estimated future development costs deducted in the estimation of future net revenue. The costs are per reserve category and quoted for undiscounted forecast prices and costs.

The Corporation anticipates funding these future development costs through a combination of internally-generated cash flow, cash on hand, consistent with the timelines for development as anticipated in the GLJ Report. Any financing costs related to funding the estimated future development costs would reduce future net revenue attributable to those reserves, however, the Corporation does not expect that such financing costs would make the development of such properties uneconomic.

Total Company Future Development Costs

	Total Proved Estimated Using Forecast Prices and Costs (M$)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (M$)
2013	133,168	145,356
2014	149,461	192,064
2015	7,777	11,002
2016	0	0
2017	0	0
5-year total	290,406	348,422
Remainder	6,624	6,624
Total for all years undiscounted	297,030	355,046

Total Colombia Future Development Costs

	Total Proved Estimated Using Forecast Prices and Costs (M$)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (M$)
2013	90,618	104,568
2014	111,017	123,257
2015	5,202	5,202
2016	0	0
2017	0	0
5-year total	206,837	233,027
Remainder	0	0
Total for all years undiscounted	206,837	233,027

Total Argentina Future Development Costs

	Total Proved Estimated Using Forecast Prices and Costs (M$)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (M$)
2013	29,850	28,088
2014	23,297	53,660
2015	2,575	5,800
2016	0	0
2017	0	0
5-year total	55,722	87,548
Remainder	6,624	6,624
Total for all years undiscounted	62,346	94,172

Total Brazil Future Development Costs

	Total Proved Estimated Using Forecast Prices and Costs (M$)	Total Proved Plus Probable Estimated Using Forecast Prices and Costs (M$)
2013	12,700	12,700
2014	15,147	15,147
2015	0	0
2016	0	0
2017	0	0
5-year total	27,847	27,847
Remainder	0	0
Total for all years undiscounted	27,847	27,847

Part 6 – Other Oil And Gas Information

Item 6.1 Oil and gas properties and wells

Oil and Gas Properties – Colombia

In June 2006, we purchased Argosy Energy International L.P. ("Argosy") which was subsequently renamed Gran Tierra Colombia Ltd. Argosy had interests in seven exploration and production contracts at that time, including the Santana, Guayuyaco, Chaza and Mecaya blocks in the Putumayo basin in southwest Colombia; the Talora and Rio Magdalena blocks in the Magdalena basin, west of Bogota; and the Primavera Block in the Llanos basin. The acquisition price included overriding royalty rights and net profits burdens in the blocks that were owned by Argosy at the time of the acquisition. The Azar Block in the Putumayo basin was acquired later in 2006, and two TEAs in the Putumayo basin (Putumayo West A and Putumayo West B) were acquired in 2007. We relinquished the Primavera Block in 2007 and we sold the Talora Block in 2009.

In November 2008, we acquired Solana which increased our interest in the Guayuyaco and Chaza blocks, and added seven blocks in three basins. The Magangue Block is located in the Lower Magdalena basin in northwest Colombia; the Catguas Block is in the Catatumbo basin which forms the southwest flank of Venezuela's Maracaibo basin; and the Guachiria Norte, San Pablo, Guachiria, Guachiria Sur and Garibay blocks are in the Llanos basin north east of Bogota. In 2009, we sold the Guachiria, Guachiria Sur and Guachiria Norte blocks and we relinquished our rights to the San Pablo Block.

In 2009, we converted portions of the two TEAs to three exploration and production blocks – part of Putumayo West A was converted to two exploration and exploitation blocks named Piedemonte Norte and Piedemonte Sur. Part of Putumayo West B was converted to the Rumiyaco Block.

In 2010, we were awarded three blocks; Cauca 6, Cauca 7 and Putumayo-10 in the Colombia Bid Round 10. Cauca 6 and Cauca 7 were TEAs and Putumayo-10 was an exploration and production block. In 2010, we also acquired an operated interest in the Putumayo-1 Block.

In March 2011, we acquired Petrolifera which added three blocks; the Sierra Nevada Block and the Magdalena Block in the Lower Magdalena Basin and the Turpial Block in the Middle Magdalena Basin.

In the fourth quarter of 2011, we entered into a farmout agreement with CEPSA Colombia S.A. ("CEPSAC"), a wholly-owned subsidiary of Compañia Española de Petróleos S.A. during 2011, whereby we earned a 45% non-operated working interest in the Llanos-22 Block and CEPSAC farmed-in for a 30% working interest on the Piedemonte Norte Block.

We have interests in 23 blocks in Colombia, and are the operator in 21 blocks. The Chaza, Guayuyaco, Garibay, and Santana Blocks have producing oil wells. The Magangué and Sierra Nevada Blocks each have one producing gas well. During the year ended December 31, 2012, 66% of our consolidated production, NAR adjusted for inventory changes, was from the Chaza Block.

In 2012, we were awarded two exploration blocks, Sinu-1 and Sinu-3 in the Sinu Basin, in the 2012 Colombia Bid Round.

Chaza Block

The Chaza Block covers 46,676 gross acres in the Putumayo Basin and is governed by the terms of an Exploration and Exploitation Contract with the ANH, which was signed June 27, 2005. We are the operator and hold a 100% working interest in this block. The discovery of the Costayaco field in the Chaza Block was the result of drilling the Costayaco-1 exploration well in the second quarter of 2007. This well commenced production in July 2007. We were granted an additional exploratory program which extended the exploration phase of the contract to June 26, 2013. The additional exploration phase required one exploration well to be drilled and this obligation was satisfied by the completion of the Pacayaco-1 and Pacayaco-1 ST1 oil exploration wells in 2011. The production phase for this block will end in 2033. After the expiration of the production phase, we must carry out an abandonment program to the satisfaction of ANH. In conjunction with the abandonment, we must establish and maintain an abandonment fund to ensure that financial resources are available at the end of the contract.

In 2012, we drilled and completed the Costayaco-15 and Costayaco-16 development wells and commenced drilling the Costayaco-17 development well in the Costayaco field. We also drilled and completed initial testing of the Moqueta-7 development well and commenced drilling the Moqueta-8 development well in the Moqueta field. We also continued facilities work at the Costayaco and Moqueta fields and acquired 3-D seismic on the Costayaco, Moqueta and Verdayaco fields.

In 2013, we plan to conduct initial testing of the Moqueta-8 development well, drill the Moqueta Deep exploration well and drill five gross development wells.

Guayuyaco Block

The Guayuyaco Block contract was signed in September 2002 and covers 52,366 gross acres in the Putumayo Basin, which includes the area surrounding the producing fields of the Santana contract area. The Guayuyaco Block is governed by an Association Contract with Ecopetrol S.A. ("Ecopetrol"), the Colombian majority state owned oil company. We are the operator and have a 70% working interest, with the remaining interest held by Ecopetrol. Ecopetrol has the option to back-in to a 30% participation interest in any other new discoveries in the block. We have completed all of our obligations in relation to this contract.

The Guayuyaco field was discovered in 2005. Two wells are now producing in this field: Guayuyaco-1 commenced production in February 2005 and Guayuyaco-2 began production in September 2005. The Juanambu field, also in the Guayuyaco Block, has three producing wells: Juanambu-1 began commercial production in November 2007, Juanambu-2 began production in March 2010 and Juanambu-3 began production in April 2011. The production phase of the contract will end in 2030, following which, the property will be returned to the government upon expiration of the production contract, and we are not obligated to perform remediation work.

In 2012, we acquired 3-D seismic on this block. In 2013, we plan to drill the Miraflor West-1 oil exploration well and an additional oil exploration well.

Garibay Block

Solana acquired the Garibay Block in October 2005. The block covers 75,936 gross acres in the Llanos Basin and we have a non-operated 50% working interest. CEPSAC has the remaining interest and is the operator. The block is held under an Exploration and Exploitation Contract with the ANH. We applied and were granted an additional exploratory program which extended the exploration phase of the contract to October 24, 2013. There was an obligation to drill one exploration well in this exploration phase, which we satisfied by drilling the Bordon-1 oil exploration well in 2012. This well was plugged and abandoned in 2012. In 2013, we plan to convert the Jilguero-2 well to a water injector well, acquire 80 square kilometers of 3-D seismic and perform facilities work.

Llanos-22 Block

During 2011, we earned a 45% non-operated working interest in the Llanos-22 Block in the Llanos Basin pursuant to farm-out agreements with CEPSAC (CEPSAC retained a 55% working interest and operatorship). CEPSAC farmed-in for a 30% working interest on the Piedemonte Norte Block. The Llanos-22 Block is held under an Exploration and Exploitation Contract with the ANH and covers 84,757 gross acres. The second exploration phase of the contract requires two wells to be drilled or one well and the relinquishment of 50% of the block prior to February 4, 2015.

Together with our partner, we successfully drilled and tested the Ramiriqui-1 oil exploration well in 2012. In 2013, we plan to drill one gross oil development well which will satisfy the second phase obligation.

Santana Block

The Santana Block contract was signed in July 1987 and covers 1,119 gross acres in the Putumayo Basin and includes 11 gross producing wells in four fields — Linda, Mary, Miraflor and Toroyaco. Activities are governed by terms of a Shared Risk Contract with Ecopetrol and we are the operator. We hold a 35% working interest in all fields and Ecopetrol holds the remaining interest. The block has been producing since 1991. Under the Shared Risk Contract, Ecopetrol initially backed into a 50% working interest upon declaration of commerciality in 1991. In June 1996, when the block reached seven MMbbl of oil produced, Ecopetrol had the right to back into a further 15% working interest, which it exercised, for a total ownership of 65%. We have completed all of our obligations in relation to the contract. The production phase of the contract will end in 2015, at which time the property will be returned to the government and we are not obligated to perform remediation work.

In 2012, we performed minor facilities maintenance. In 2013, no significant capital expenditures are planned.

Sierra Nevada Block

We acquired our interest in the Sierra Nevada Block through the Petrolifera acquisition in March 2011. The Sierra Nevada Block is located in the Lower Magdalena Basin and covers 178,162 gross acres. We are the operator of the block with a 100% working interest. The block is held under an Exploration and Exploitation Contract with the ANH and a third party has a 1% overriding royalty right on the block. We are in the fourth of six exploration phases, which would have ended on December 28, 2012, but we applied to the ANH and were granted a two-month extension to February 28, 2013. The final exploration phase is scheduled to end in June 2014 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we drilled the Florida West exploration well, which was plugged and abandoned and satisfied the fourth phase commitment, and relinquished 15% of the block. In 2013, no significant capital expenditures are planned.

Magdalena Block

We acquired our interest in the Magdalena Block through the Petrolifera acquisition in March 2011. The Magdalena Block is located in the Lower Magdalena Basin and covers 594,803 gross acres. We are the operator of the block with a 100% working interest. The block is held under an Exploration and Exploitation Contract with the ANH and a third party has a 1% overriding royalty right on the block. We are in the third of six exploration phases, which ends on May 1, 2013, and required one exploration well to be drilled; however, we requested and were granted ANH approval to change the work obligation to a 2-D seismic program. The final exploration phase is scheduled to end in February 2016 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we acquired 53 square kilometers of 3-D seismic on this block. In 2013, we plan to acquire 85 kilometers of 2-D seismic on this block to satisfy the third phase obligation.

Piedemonte Norte Block

In June 2009, we completed the conversion of our Technical Evaluation Areas ("TEA") in the Putumayo Basin to blocks with Exploration and Exploitation Contracts with the ANH. The Piedemonte Norte Block covers 78,742 gross acres in the Putumayo Basin and we hold a 70% working interest. In 2011, we farmed out 30% of the block to CEPSAC, but retained operatorship. This asset swap was in connection with the Llanos-22 Block farm-in agreement. The first exploration phase was to end on October 10, 2012, and required the acquisition, processing and interpretation of 70 kilometers of 2-D seismic; however, the block is under suspension pending receipt of an environmental permit. This contract has six exploration phases and the final exploration phase of the contract ends in October 2017; however, since this block is under suspension, the contract expiration will likely be delayed. The exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures. In 2013, we plan to acquire 70 kilometers of 2-D seismic on this block which will satisfy the first phase obligation.

Piedemonte Sur Block

The Piedemonte Sur Block was part of the Putumayo West A TEA and became an exploration block with an Exploration and Exploitation Contract with the ANH in June 2009. The Piedemonte Sur Block covers 73,898 gross acres in the Putumayo Basin. We are the operator of the block with a 100% working interest. We are in a unified phase two and three of six exploration phases. This phase requires the acquisition of 55 kilometers of 2-D seismic and the drilling of one exploration well by July 26, 2013; however, we expect to apply for an extension of this phase. The exploration phase will end in July 2016 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures. In 2013, we plan to acquire 51 kilometers of 2-D seismic on this block.

Magangué Block

Solana acquired the Magangué Block in October 2006. It is held pursuant to an Association Contract with Ecopetrol and covers 20,647 gross acres in the Lower Magdalena Basin. We are the operator of the block with a 42% working interest and our partner Ecopetrol has the remaining working interest. This block contains the producing Guepaje gas field. The production phase of the contract will end in 2017. We have completed all of our obligations in relation to the contract.

In 2012, there were no significant capital expenditures on this block and no significant capital expenditures are planned for 2013.

Mecaya Block

The Mecaya Exploration and Exploitation Contract with the ANH was signed June 2006. The Mecaya Block covers 74,128 gross acres in the Putumayo Basin. We are the operator and have a 15% working interest. Two partners have the remaining working interest. We are in a unified phase one and two of four exploration phases and are obligated to complete 52 square kilometers of 3-D seismic or drill one exploration well. We were contractually obligated to complete this work by June 2009; however, the contract terms have been suspended due to operational difficulties in the area. The exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures on this block, and no significant capital expenditures are planned for 2013.

Cauca 6 Block

We were awarded the Cauca 6 Block in the 2010 Colombia Bid Round. The block covers 571,098 gross acres in the Cauca Basin. We are the operator of the block with a 100% working interest. The block is held under a TEA Contract with the ANH. We are in the exploration phase of the contract which requires the acquisition of 200 kilometers of 2-D seismic and the drilling of one stratigraphic well by December 15, 2014. This TEA contract would then be converted into an Exploration and Exploitation Contract.

In 2012, we conducted surface and subsurface geological studies and an aeromagnetic survey. In 2013, we plan to acquire 200 kilometers of 2-D seismic on this block.

Cauca 7 Block

We were awarded the Cauca 7 Block in the 2010 Colombia Bid Round. The block covers 785,452 gross acres in the Cauca Basin. We are the operator of the block with a 100% working interest. The block is held under a TEA Contract with the ANH. The exploration phase of the contract requires the acquisition of 250 kilometers of 2-D seismic and the drilling of one stratigraphic well by December 15, 2014. This TEA contract would then be converted into an Exploration and Exploitation Contract.

In 2012, we conducted surface and subsurface geological studies and an aeromagnetic survey. In 2013 we plan to acquire 250 kilometers of 2-D seismic on this block.

Putumayo 10 Block

We were awarded the Putumayo 10 Block in June 2010 in the 2010 Colombia Bid Round. The block covers 114,096 gross acres in the Putumayo Basin. We are the operator of the block with a 100% working interest. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the first of two exploration phases of the contract. This phase requires the acquisition of 73 kilometers of 2-D seismic and two exploration wells to be drilled by September 15, 2014. The exploration phase ends in September 2017 and the exploitation phase would end 24 years after commerciality if a discovery is approved.

In 2012, there were no significant capital expenditures. In 2013, we plan to acquire 100 kilometers of 2-D seismic on this block.

Putumayo 1 Block

We acquired a 55% operated working interest in the Putumayo-1 Block in 2010. The block covers 114,881 gross acres in the Putumayo Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the first of two exploration phases. This phase required the acquisition of 159 square kilometers of 3-D seismic and one exploration well to be drilled by May 3, 2012; however, we requested and were granted an extension to May 3, 2013. The exploration phase ends in September 2015 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we initiated the acquisition of 3-D seismic on this block and, in 2013, we plan to acquire a further 228 square kilometers of 3-D seismic and drill one gross oil exploration well.

Catguas A and B Blocks

Solana acquired the Catguas Block in November 2005. We are the operator of the block which covers 330,354 gross acres in the Catatumbo Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We have a 100% working interest in the block; however, in December 2005, Solana and its partner signed a participation agreement whereby they defined the areas A and B and distributed them between the partners in the block. The participation agreement will transfer a 15% working interest in the southern part of the block (Catguas B) and a 50% working interest in the remainder of the block (Catguas A) to our partner. This agreement is subject to approval by ANH. Catguas A covers 74,119 gross acres and Catguas B covers 256,235 gross acres. We are in a unified phase two and three of six exploration periods in the contract. This phase was to end in May 2007; however, the block contract is in suspension by ANH as a result of force majeure. This phase requiresthree exploratory wells or two exploratory wells to be drilled and one re-entry and the acquisition of 50 square kilometers of 3-D seismic. There will be two subsequent exploration periods of 12 months each in length, which both require the drilling of one exploration well. The exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, there were no significant capital expenditures on this block, and no significant capital expenditures are planned for 2013.

Sinu-1 Block

We acquired a 60% operated working interest in the Sinu-1 Block in the 2012 Colombia Bid Round. The block covers 503,000 gross acres in the Sinu Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the community consultation phase which will end on November 28, 2013.

Sinu-3 Block

We acquired a 51% operated working interest in the Sinu-3 Block in the 2012 Colombia Bid Round. The block covers 483,000 gross acres in the Sinu Basin. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the community consultation phase which will end on November 28, 2013.

Turpial Block

We acquired our interest in the Turpial Block through the Petrolifera acquisition in March 2011. The Turpial block is located in the Middle Magdalena Basin in central Colombia and covers 111,066 gross acres. We are the operator of the block with a 50% working interest and our partner holds the remaining working interest. The block is held under an Exploration and Exploitation Contract with the ANH and a third party has a 1% overriding royalty right on the block. We are in the fourth phase of six exploration phases. This phase requires one exploration well to be drilled by November 3, 2013. The exploration phase will end in August 2015 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we drilled the Turpial-1 oil exploration well which satisfied the fourth exploration phase commitment. In 2013, no significant capital expenditures are planned.

Azar Block

We have a 100% working interest in the Azar Block; however, we have entered two farm-out agreements to transfer 60% of our working interest. The farm-outs are subject to ANH approval. This block covers 47,226 gross acres in the Putumayo Basin and we are the operator. The block is held under an Exploration and Exploitation Contract with the ANH. We are in the sixth exploration phase which requires one exploration well to be drilled. The exploitation phase would end 24 years after commerciality, if a discovery is approved. The property will be returned to the government upon expiration of the production contract. If we make a commercial discovery on the block and produce oil, we will be obligated to perform abandonment activities under the same conditions as those for the Chaza Block.

In 2012, we drilled the La Vega Este-1 oil exploration well which was plugged and abandoned during the year, and satisfied the fifth exploration phase well commitment. In 2013, no significant capital expenditures are planned.

Rumiyaco Block

The Rumiyaco Block was part of the Putumayo West B TEA and became an exploration block with an Exploration and Exploitation Contract with the ANH in June 2009. Rumiyaco covers 82,624 gross acres in the Putumayo Basin. We are the operator of the block with a 100% working interest. We are in the fourth of six exploration phases. This phase requires one exploration well to be drilled by September 4, 2013. The exploration phase ends in September 2015 and the exploitation phase would end 24 years after commerciality, if a discovery is approved.

In 2012, we acquired 52 square kilometers of 3-D seismic on this block. In 2013, no significant capital expenditures are planned.

Rio Magdalena Block

The Rio Magdalena Association Contract with Ecopetrol was signed in February 2002. The Rio Magdalena Block covers 36,156 gross acres in the Magdalena Basin. We are the operator of the block and hold a 70% working interest. An agreement to transfer a further interest to our partner and reduce our working interest to 30.8% is pending approval by Ecopetrol. According to the terms of the Association Contract, Ecopetrol may back-in for a 30% working interest in any discoveries on the block upon commercialization. The exploration phase of the contract ended on September 14, 2010, and the production period will end in 2030, at which time the property will be returned to the government. As a result, there will be no reclamation costs.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

Oil and Gas Properties – Argentina

Our Argentina properties are located in the Noroeste Basin in northern Argentina and the Neuquen Basin in central Argentina. The Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Surubi, El Chivil, Palmar Largo and El Vinalar Blocks have producing oil wells and the Puesto Morales Block also has producing gas wells. During the year ended December 31, 2012, 12% of our consolidated production, NAR adjusted for inventory changes, was from the Puesto Morales Block and 6% was from the Surubi Block. For all of our blocks in Argentina, upon expiry of the block rights, ownership of producing assets will revert to the provincial government.

As some of our oil production in Argentina is trucked to a local refinery, sales of oil in the Noroeste Basin can be seasonally delayed by adverse weather and road conditions, particularly during the months November through February when the area is subject to periods of heavy rain and flooding. While storage facilities are designed to accommodate ordinary disruptions without curtailing production, delayed sales will delay revenues and may adversely impact our working capital position in Argentina.

We relinquished our interest in the Puesto Guevara Block during 2012.

Royalties in Argentina are based on a provincial royalty plus an additional provincial turnover tax. The provincial royalty rate is 24% for the Puesto Morales Este Block and 12% on all other blocks in Argentina. The provincial turnover tax ranges from 1.5% to 3% on our blocks.

Rio Negro Province, which includes the Puesto Morales, Puesto Morales Este, Rinconada Norte and Rinconada Sur Blocks, has enacted new legislation that changes the royalty regime associated with concession agreement extensions. Royalties in Rio Negro Province will increase a minimum of 3.5% and a required bonus payment, not determinable at this time, will be negotiated for the concession agreement extension. In addition, there is an additional royalty component of 0.5% per dollar per bbl on realized oil prices greater than $80 per bbl and 0.5% per dollar per MMBtu for gas prices above $3.50 per MMBtu. Under the new legislation, negotiations are required to be carried out within the first half of 2013 and the resulting new terms are expected to come into effect immediately thereafter.

Puesto Morales Block

We acquired our interest in the Puesto Morales Block through the Petrolifera acquisition in March 2011. The Puesto Morales Block covers 31,254 gross acres. We are the operator of the block with a 100% working interest. The contract was awarded on October 18, 2010, and the exploitation phase will end on January 22, 2016, with a possible ten year extension. We have commenced negotiations for an extension. We have no work commitments on this block.

In 2012, we drilled and completed seven development wells and commenced drilling an additional two development wells, one of which was suspended, continued a well workover program, commenced a waterflood program and performed facility upgrades. In 2013, we plan to drill five development wells, continue the waterflood and workover programs and perform facilities upgrades.

Rinconada Sur Block

We acquired our interest in the Rinconada Sur Block through the Petrolifera acquisition in March 2011. The Rinconada Sur Block covers 28,417 gross acres and is part of the Puesto Morales concession. We are the operator of the block with a 100% working interest. The contract was awarded on October 18, 2010, and the exploitation phase will end on January 22, 2016, with a possible ten year extension. We have no work commitments on this block.

In 2012, we completed one development well and drilled one exploration well which was plugged and abandoned subsequent to year-end. In 2013, no significant capital expenditures are planned.

Puesto Morales Este Block

We acquired our interest in the Puesto Morales Este Block through the Petrolifera acquisition in March 2011. The Puesto Morales Este Block covers 1,483 gross acres. We are the operator of the block with a 100% working interest. The contract was awarded on October 18, 2010, and the exploitation phase will end on October 17, 2035, with a possible five year extension. We have no work commitments on this block.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

Rinconada Norte Block

We acquired our interest in the Rinconada Norte Block through the Petrolifera acquisition in March 2011. The Rinconada Norte Block covers 23,475 gross acres. We have a 35% non-operated working interest. Our partner is the operator and has the remaining working interest. This is an exploitation concession and the exploitation phase will end on January 22, 2016, with a possible ten year extension. We have no work commitments on this block.

In 2012, our partner drilled four gross exploration wells and three gross development wells. One exploration well was producing at year-end, one was plugged and abandoned and two were under evaluation. One development well was completed during the year and two wells were in progress at year-end. In 2013, no significant capital expenditures are planned.

Surubi Block

We purchased the Surubi Block in late 2006. We are the operator of the Surubi Block, which covers 90,811 gross acres, and have an 85% working interest. In 2008, we drilled the Proa-1 discovery well, which began production in September 2008. The provincial oil company, Recursos Energeticos Formosa S.A., farmed-in to the block for a 15% working interest, and is paying its share of well costs from its share of production from the Proa-1 well. The contract for this block will end on August 17, 2026. We have no work commitments on this block.

In 2012, we drilled and completed the Proa-2 development well, which began production in April 2012. In 2013, we plan to perform facilities work.

El Chivil Block

We purchased the El Chivil Block in 2006. We are the operator and hold a 100% working interest in the block which covers 30,393 gross acres. The contract for this block will end on September 7, 2015, with a possible ten year extension. We have no work commitments on this block.

In 2012, regular field maintenance and workover activities were performed and the same are planned for 2013.

Palmar Largo Block

We purchased a 14% non-operated working interest in the Palmar Largo Block in September 2005. Three partners hold the remaining working interest. The Palmar Largo Block covers 186,441 gross acres. This asset comprises several producing oil fields in the Noroeste Basin and is subdivided into three sub-blocks, including Balbuena Este. The Palmar Largo Block contract will end in 2017, with a possible ten year extension. We have no work commitments on this block.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

El Vinalar Block
In June 2006, we acquired a 50% working interest in the El Vinalar Block, which covers 61,035 gross acres. We are the operator of the block. The El Vinalar Block contract will end on April 19, 2016, with a possible ten year extension. We have no work commitments on this block.

In 2012, there were no significant capital expenditures. In 2013, we plan to perform workovers and facilities upgrades.

Valle Morado Block
We purchased our original interest in the Valle Morado Block in 2006 and purchased a further 3.4% working interest during 2011. This block covers 44,446 gross acres and we are the operator with a 96.6% working interest. The Valle Morado GTE.St.VMor-2001 well was first drilled in 1989. A previous operator completed a 3-D seismic program over the field and constructed a gas plant and pipeline infrastructure. Production began in 1999 from the GTE.St.VMor-2001 well, but was shut-in in 2001 due to water incursion. During 2008, we performed long-term testing on the well. In July 2010, we commenced a re-entry and sidetrack operation on the well; however, these operations were suspended in February 2011 and the wellbore was abandoned due to operational challenges. We continue to review alternatives associated with the field development. The contract for this block expires in 2034. We have no work commitments on this block. In 2012, there were no significant capital expenditures and no significant expenditures are planned for 2013.

Santa Victoria Block
We purchased the Santa Victoria Block in 2006. This block covers 516,942 gross acres. We are the operator and have a 50% working interest. In 2011, we relinquished 50% of the block as a condition to enter into the second phase and also farmed-out 50% of our working interest. In 2013, we expect to assume, subject to regulatory approval, a 100% working interest, due to our joint venture partner's decision to leave the joint venture. We are in the second of three exploration phases. This phase requires one exploration well to be drilled or 720 units of work ($3.6 million) to be completedby March 29, 2013, but we have commenced negotiations to extend the expiry date of this phase. The exploration phase ends in March 2014. In 2012, there were no significant capital expenditures. In 2013, we plan to drill a gas exploration well.

Vaca Mahuida Block
We acquired our interest in the Vaca Mahuida Block through the Petrolifera acquisition in March 2011. The Vaca Mahuida Block covers 253,331 gross acres. We are the operator and have a 25% working interest. Our three partners share the remaining working interest. After three gas discoveries in 2010, an exploitation concession was requested and we are awaiting regulatory approval. We satisfied our obligation to perform long-term production gas tests and are evaluating the potential of these prospects and the block. We have no work commitments on this block.

In 2012, there were no significant capital expenditures and no significant capital expenditures are planned for 2013.

Oil and Gas Properties – Peru

On January 17, 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block and operatorship to us. During June 2012, we entered into an agreement to acquire the remaining 40% working interest in Block 95. Subsequent to December 31, 2012, we received regulatory approval for the assignment of the remaining 40% working interest. In the fourth quarter of 2012, we increased our working interest in Blocks 123 and 129 to 100%, subject to regulatory approval, and, in January 2013, assumed operatorship.

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

Block 95
In December 2010, we acquired a 60% working interest in Block 95 and, during the second quarter of 2012, we entered into an agreement to acquire the remaining 40% working interest. Subsequent to December 31, 2012, we received regulatory approval and the Public Deed for the assignment of the remaining interest. We are the operator of this block. Block 95 has an area of 1,274,399 gross acres. An oil field has already been discovered on Block 95, with a discovery well drilled in 1974 flowing 807 BOPD naturally without pumps. We are in the third exploration phase of six which required the drilling of one well or the completion of 400 units of work. This phase was delayed as a result of force majeure. Force majeure ended in December 2012 and we were granted a six month extension to June 27, 2013. In 2012, we completed civil construction of a drilling platform and dock facility and commenced drilling an oil exploration well. We also applied for a variety of permits in preparation for drilling the oil exploration well and for future seismic programs. In 2013, we completed drilling of the exploration well and obtained initial well-log results, which indicated an oil saturated reservoir. We plan to extend the exploration well with a horizontal leg to initiate long-term testing. Timing for initiation of the long-term testing has not been determined yet, but it is expected to commence within a period of 12 months, subject to facilities upgrade, and execution of crude oil transportation and delivery agreements.

Block 123 and Block 129

In September 2010, we acquired a 20% working interest in Block 123 and Block 129. In October 2012, we increased our working interest in Blocks 123 and 129 to 100% through the assumption of our partners' interests, subject to regulatory approval, and assumed operatorship on January 1, 2013. Blocks 123 and 129 have a total area of 3,491,240 gross acres. We are in the third exploration phase of five on Block 123, which was to end on November 29, 2012, but we applied for and were granted two three month extensions to May 31, 2013. On Block 129, the third exploration phase of five was due to end on February 26, 2013, but we applied for and were granted a six month extension to August 26, 2013. This phase requires the acquisition of 2-D seismic totaling 504 kilometers over the two blocks.

In 2012, we acquired 2-D seismic on these blocks. In 2013, we plan to acquire 567 kilometers of 2-D seismic and pursue Environmental Impact Assessment ("EIA") approvals.

Block 107

We acquired our interest in Block 107 through the Petrolifera acquisition in March 2011. Block 107 covers 623,504 gross acres. We are the operator of the block with a 100% working interest and a third party has a 3% overriding royalty right on the block. We are in the fourth and final exploration phase, which requires one exploration well to be drilled or 300 units of work. The block has been under force majeure since May 25, 2012. The fourth phase will end 12 months after force majeure is lifted, but we plan to apply for an extension of the exploration period.

In 2012, we acquired an overriding royalty right that was held by a third party and advanced permitting for drilling. In 2013, we plan to complete a 392 kilometer infill 2-D seismic program, which will satisfy our fourth phase work obligation, and begin pre-drilling activities.

Block 133

We acquired our interest in Block 133 through the Petrolifera acquisition in March 2011. Block 133 covers 978,663 gross acres. We are the operator of the block with a 100% working interest. We are in the second exploration phase of four, which was to end on February 14, 2013; however, PeruPetro has frozen the phase until June 7, 2013. This phase requires the acquisition of 150 kilometers of 2-D seismic which will be followed by the relinquishment of 20% of the block.

In 2012, we performed G&G studies. In 2013, we plan to complete airborne gravity and magnetic surveys and request approval for this work to satisfy the second phase work obligation. We also plan to continue EIAs.

Oil and Gas Properties - Brazil

In September 2012, we received declaration of commerciality for the Tiê field on Block REC-T-155. On October 8, 2012, we received Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") approval and acquired the remaining 30% working interest in our four exploration blocks in the Recôncavo Basin pursuant to the terms of a purchase and sale agreement dated January 20, 2012. With the exception of one block which has three producing wells, the remaining blocks are unproved properties.

In September 2011, we announced farm-out agreements with Statoil pursuant to which we would receive an assignment from Statoil of a non-operated 10% working interest in Block BM-CAL-7 and a non-operated 15% working interest in Block BM-CAL-10. In 2012, we received ANP approval for Block BM-CAL-7 and the assignment became effective on April 3, 2012.

During the first quarter of 2012, the ANP announced the 1-STAT-7-BAS exploration well drilling had been completed on Block BM-CAL-10. In accordance with the terms of the farm-out agreement, we gave notice to Statoil that we would not enter into and assume our share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farm-out agreement terminated and we did not receive any interest in Block BM-CAL-10.

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

Blocks REC-T-129, REC-T-142, REC-T-155, and REC-T-224

Blocks REC-T-129, REC-T-142, REC-T-155 and REC-T-224 are located approximately 70 kilometers northeast of Salvador, Brazil in the Recôncavo Basin and cover 27,075 gross acres. We are the operator with a 100% working interest. On October 8, 2012, we received regulatory approval and acquired the remaining 30% working interest in these blocks. All four blocks are in the second exploration phase which will end in the fourth quarter of 2013. This phase requires the drilling of an exploration well on each block.

In 2012, we drilled and completed two development wells, 3-GTE-03-BA and 4-GTE-04-BA, in the Tiê field on Block REC-T-155 and drilled a horizontal oil exploration well, 1-GTE-05HP-BA, on Block REC-T-142. In 2013, we plan to drill two horizontal exploration wells on Block REC-T-155 and Block REC-T-129, perform additional completion work on the 3-GTE-03-BA and 3-GTE-04-BA producing wells in the Tiê field and perform fracture stimulation operations on Block REC-T-142. We also plan to perform facilities and pipeline work on Block REC-T-155.

Block BM-CAL-7

Block BM-CAL-7 is located in the Camamu Basin, offshore Bahia, Brazil and covers 337,561 gross acres. We have a 10% non-operated working interest in this block. We received ANP approval for this working interest during 2012 and the assignment became effective on April 3, 2012. Block BM-CAL-7 is in the first of two exploration phases which is due to end in April 2013, but we have applied to the ANP for a 12 month extension. This phase requires one exploration well to be drilled and the acquisition of 1,366 square kilometers of 3-D seismic. Our partner had previously satisfied the seismic commitment and, in 2012, we purchased an existing 3-D seismic program. In 2013, we plan to conduct evaluation work to mature prospects for drilling expected to take place in 2014.

Oil and Gas Wells

The following table summarizes the Corporation's existing wells as at December 31, 2012:

Existing Wells at December 31, 2012

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Colombia				
Producing	30.00	22.00	0.00	0.00
Non-Producing	4.00	2.77	2.00	1.42
Sub-total	34.00	24.77	2.00	1.42
Argentina				
Producing	89.00	74.13	7.00	7.00
Non-Producing	15.00	4.04	0.00	0.00
Sub-total	104.00	78.17	7.00	7.00
Brazil				
Producing	3.00	3.00	0.00	0.00
Non-Producing	0.00	0.00	0.00	0.00
Sub-total	3.00	3.00	0.00	0.00
Total	141.00	105.94	9.00	8.42

Item 6.2 Properties with no attributed reserves

Exploration Properties	Gross Acres	Net Acres
Colombia	4,000,524	3,357,947
Argentina	516,942	258,471
Peru	6,367,807	6,367,807
Brazil	358,850	55,045
Total	11,244,123	10,039,270

240,134 gross acres in Colombia with no attributed reserves will expire within one year.

Item 6.4 Additional information concerning abandonment and reclamation costs

The Corporation incurred $0.1 million in abandonment and reclamation costs in Colombia during the year-ended December 31, 2012. The Corporation incurred US$0.4 million in abandonment and reclamation costs in Argentina during the year-ended December 31, 2012.

The Corporation estimates that 164.73 net wells will be abandoned in the proved case and 188.78 net wells will be abandoned in the proved plus probable case.

Abandonment costs are calculated based on historical data and current conditions.

The GLJ Report includes well abandonment costs in estimating future net revenues as follows:

Consolidated Abandonment and Reclamation Costs

Portion deducted in estimating future net revenue	Total Proved (forecast prices and costs) M$ (undiscounted)	Total Proved (forecast prices and costs) M$ (discounted at 10%)	Total Proved Plus Probable (forecast prices and costs) M$ (undiscounted)	Total Proved Plus Probable (forecast prices and costs) M$ (discounted at 10%)
2013	0	0	0	0
2014	601	521	510	442
2015	2,029	1,598	2,007	1,581
Remainder	20,648	6,614	22,928	5,736
Total	23,278	8,733	25,445	7,759

Colombia Abandonment and Reclamation Costs

Portion deducted in estimating future net revenue	Total Proved (forecast prices and costs) M$ (undiscounted)	Total Proved (forecast prices and costs) M$ (discounted at 10%)	Total Proved Plus Probable (forecast prices and costs) M$ (undiscounted)	Total Proved Plus Probable (forecast prices and costs) M$ (discounted at 10%)
2013	0	0	0	0
2014	51	44	0	0
2015	1,748	1,377	1,748	1,377
Remainder	15,288	4,018	16,465	3,265
Total	17,087	5,439	18,213	4,642

Argentina Abandonment and Reclamation Costs

Portion deducted in estimating future net revenue	Total Proved (forecast prices and costs) M$ (undiscounted)	Total Proved (forecast prices and costs) M$ (discounted at 10%)	Total Proved Plus Probable (forecast prices and costs) M$ (undiscounted)	Total Proved Plus Probable (forecast prices and costs) M$ (discounted at 10%)
2013	0	0	0	0
2014	40	35	0	0
2015	281	221	259	204
Remainder	3,909	1,853	4,914	1,869
Total	4,230	2,109	5,173	2,073

Brazil Abandonment and Reclamation Costs

Portion deducted in estimating future net revenue	Total Proved (forecast prices and costs) M$ (undiscounted)	Total Proved (forecast prices and costs) M$ (discounted at 10%)	Total Proved Plus Probable (forecast prices and costs) M$ (undiscounted)	Total Proved Plus Probable (forecast prices and costs) M$ (discounted at 10%)
2013	0	0	0	0
2014	510	442	510	442
2015	0	0	0	0
Remainder	1,451	743	1,549	602
Total	1,961	1,185	2,059	1,044

Item 6.5 Tax horizon

The Corporation is currently subject to income tax in Argentina and Colombia. In Brazil, though currently not subject to income tax, the Corporation is expected to have some income taxes payable in the immediate future. The Corporation is not expected to have income taxes payable in Peru, United States or Canada in the immediate future, subject to changes in the business model or significant increases to commodity prices.

Item 6.6 Costs incurred

The following table shows the dollar amounts expended by the Corporation on property acquisitions and exploration and development for the year ended December 31, 2012.

2012 Costs Incurred

	Colombia M$	Argentina M$	Brazil M$	Total M$
Proved property acquisitions	$24	$0	$24	$48
Unproved property acquisitions	$0	$0	$37	$37
Exploration	$33	$1	$19	$53
Development (including facilities)	$95	$38	$11	$144
Total	$152	$39	$91	$282

Item 6.7 Exploration and development activities

The following table sets forth the number of exploratory and development wells which the Corporation completed during the year ended December 31, 2012:

Exploration & Development Activities For 2012

Colombia	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil wells	1.00	0.45	1.00	1.00
Gas wells	0.00	0.00	0.00	0.00
Service wells	0.00	0.00	2.00	2.00
In Progress	2.00	1.50	2.00	2.00
Dry holes	2.00	0.90	0.00	0.00
Total wells	5.00	2.85	5.00	5.00

Argentina	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil wells	0.00	0.00	12.00	9.90
Gas wells	0.00	0.00	0.00	0.00
Service wells	0.00	0.00	0.00	0.00
In Progress	3.00	1.70	2.00	2.00
Dry holes	2.00	1.35	0.00	0.00
Total wells	5.00	3.05	14.00	11.90

Brazil	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil wells	0.00	0.00	0.00	0.00
Gas wells	0.00	0.00	0.00	0.00
Service wells	0.00	0.00	0.00	0.00
In Progress	1.00	1.00	0.00	0.00
Dry holes	0.00	0.00	0.00	0.00
Total wells	1.00	1.00	0.00	0.00

Peru	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil wells	0.00	0.00	0.00	0.00
Gas wells	0.00	0.00	0.00	0.00
Service wells	0.00	0.00	0.00	0.00
In Progress	1.00	1.00	0.00	0.00
Dry holes	0.00	0.00	0.00	0.00
Total wells	1.00	1.00	0.00	0.00

Company	Exploration Wells		Development Wells	
	Gross	Net	Gross	Net
Oil wells	1.00	0.45	13.00	10.90
Gas wells	0.00	0.00	0.00	0.00
Service wells	0.00	0.00	2.00	2.00
In Progress	7.00	5.20	4.00	4.00
Dry holes	4.00	2.25	0.00	0.00
Total wells	12.00	7.90	19.00	16.90

During 2013 capital expenditures will be split between Colombia, Peru, Argentina and Brazil.

The 2013 capital program in Colombia is $224 million with $119 million allocated to drilling , $39 million to facilities and pipelines and $66 million for G&G expenditures.

Our planned work program for 2013 in Colombia includes drilling one gross oil exploration well on each of the Chaza and Putumayo-1 Blocks (100 % WI, operated) and two gross exploration wells on the Guayayaco Block (70% WI, operated). We plan to drill six gross development wells and convert an existing well on the Garibay Block (50 % WI, operated) to a water injector well. Development wells are planned for the Chaza (both Costayaco and Moqueta fields) and Llanos-22 Blocks.

We also plan to acquire 2-D seismic on the Cauca-6, Cauca-7, Putumayo-10, Magdalena, Piedemonte Norte and Piedemonte Sur Blocks and 3-D seismic on the Garibay and Putumayo-1 Blocks. Facilities work is also planned for the Chaza, Garibay and Santana Blocks.

The 2013 capital program in Argentina is $31 million with $19 million allocated to drilling, $6 million to facilities and pipelines, and $6 million to G&G expenditures.

Our planned work program for 2013 in Argentina includes drilling one gross exploration well on the Santa Victoria Block (50% WI, operated), five development wells on the Puesto Morales Block and workovers on existing wells. We also plan to acquire G&G on the Puesto Morales Block and the Valle Morado Block and perform facilities work on the El Chivil Block.

The 2013 capital program in Peru is $38 million with $21 million allocated to drilling, to acquisitions, $2.0 million for facilities and $15 million for G&G expenditures.

Our planned work program for 2013 in Peru includes drilling and the evaluation of results of an oil exploration well on Block 95, the acquisition of 2D seismic on Block 123, Block 129 and Block 107, the commencement of an aeromagnetic and aerogravity survey and Environmental Impact Assessments on Block 133 and environmental health and safety programs on all blocks.

The 2013 capital program in Brazil is $67 million with $43 million allocated to drilling, to acquisitions, $18 million to facilities and pipelines and and $6.0 million for G&G and other expenditures.

Our planned work program for 2013 in Brazil includes drilling two horizontal sidetrack oil exploration wells on Block REC-T-155 and Block REC-T-142 (100% WI and operator), additional completion work on the 3-GTE-03-BA and 3-GTE-04-BA producing wells in the Tiê field and fracture stimulation operations on Block REC-T-142.

We also plan to perform facilities and pipeline work on Block REC-T-155.

Item 6.8 Production estimates

The following table sets forth the rates of production estimated for 2013 (the first year reflected in the reserve estimates):

Company	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	9,444	25,873	1,728	4,734	26	70
Total Probable	574	1,573	89	417	2	5
Total Proved Plus Probable	10,018	27,446	1,817	5,151	28	75

Colombia	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	7,978	21,856	829	2,272	3	7
Total Probable	319	875	64	174	0	0
Total Proved Plus Probable	8,297	22,731	893	2,446	3	7

Argentina	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	1,149	3,149	899	2,462	23	63
Total Probable	97	264	25	243	2	5
Total Proved Plus Probable	1,246	3,413	924	2,705	25	68

Brazil	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	317	868	0	0	0	0
Total Probable	158	434	0	0	0	0
Total Proved Plus Probable	475	1,302	0	0	0	0

In Colombia, production from the Costayaco field accounts for greater than 20% of the estimated production for fiscal year 2013. The Costayaco field accounts for 73% of the estimated proved production for fiscal year 2013 and 71% of the estimated proved plus probable production for Colombia.

In Argentina, production from the Puesto Morales and Surubi fields account for greater than 20% each of the estimated production for fiscal year 2012. The Puesto Morales field accounts for 58% of the estimated proved production for fiscal year 2013 and 58% of the estimated proved plus probable production. The Surubi field accounts for 27% of the estimated proved production for fiscal year 2013 and 26% of the estimated proved plus probable production for Argentina.

In Brazil, production from Block 155 in the Reconcavo field accounts for greater than 20% of the estimated proved production for fiscal 2013. Block 155 accounts for 100% of the estimated proved production for Brazil.

Production estimated for fiscal 2013 for each of these fields is set out in the table below:

Properties accounting for > 20% of production estimates in each country:

Colombia: Costayaco Field	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	5,817	15,937	0	0	0	0
Total Probable	105	288	0	0	0	0
Total Proved Plus Probable	5,922	16,225	0	0	0	0

Argentina: Puesto Morales	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	668	1,829	899	2,462	23	63
Total Probable	58	160	89	243	2	5
Total Proved Plus Probable	726	1,989	988	2,705	25	68

Argentina: Surubi	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	305	837	0	0	0	0
Total Probable	23	62	0	0	0	0
Total Proved Plus Probable	328	899	0	0	0	0

Brazil: Block 155	Light & Medium Oil		Natural Gas		Natural Gas Liquids	
	Gross Mbbl	Gross bbl/d	Gross MMcf	Gross Mcf/d	Gross Mbbl	Gross bbl/d
Total Proved	317	868	0	0	0	0
Total Probable	158	434	0	0	0	0
Total Proved Plus Probable	475	1,302	0	0	0	0

Item 6.9 Production history

The following table sets forth certain information in respect of production, product prices received, royalties, production costs and netbacks received by the Corporation for each quarter of the year ended December 31, 2012:

Colombia – 2012

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Average Production				
Light & Medium Oil (bbl/d)	18,870	14,695	21,644	17,781
Natural Gas (Mcf/d)	162	712	923	128
NGL's ($/bbl)	–	–	–	–
Selling Prices				
Light & Medium Oil ($/bbl)	110.92	98.96	101.81	99.40
Natural Gas ($/Mcf)	3.39	2.62	2.62	10.44
NGL's ($/bbl)	–	–	–	–
Royalties				
Light & Medium Oil ($/bbl)	30.20	30.27	28.79	27.73
Natural Gas ($/Mcf)	1.22	0.25	0.25	1.79
NGL's ($/bbl)	–	–	–	–
Production Costs				
Light & Medium Oil ($/bbl)	9.37	12.94	13.38	15.63
Natural Gas ($/Mcf)	25.74	6.39	4.35	54.97
NGL's ($/bbl)	–	–	–	–
Netbacks(1)				
Light & Medium Oil ($/bbl)	71.34	55.76	59.65	56.05
Natural Gas ($/Mcf)	(23.57)	(4.02)	(1.98)	(46.33)
NGL's ($/bbl)	–	–	–	–

Argentina – 2012

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Average Production				
Light & Medium Oil (bbl/d)	2,474	3,516	3,589	3,363
Natural Gas (Mcf/d)	4,515	4,071	4,153	4,406
NGL's ($/bbl)	–	–	–	–
Selling Prices				
Light & Medium Oil ($/bbl)	70.87	71.32	72.05	70.13
Natural Gas ($/Mcf)	3.42	4.00	4.34	3.63
NGL's ($/bbl)	–	–	–	–
Royalties				
Light & Medium Oil ($/bbl)	8.13	8.12	8.68	8.01
Natural Gas ($/Mcf)	0.40	0.60	0.65	0.56
NGL's ($/bbl)	–	–	–	–
Production Costs				
Light & Medium Oil ($/bbl)	32.24	27.61	24.48	26.22
Natural Gas ($/Mcf)	0.22	0.31	0.30	0.23
NGL's ($/bbl)	–	–	–	–
Netbacks(1)				
Light & Medium Oil ($/bbl)	30.50	35.59	38.89	35.90
Natural Gas ($/Mcf)	2.81	3.10	3.39	2.84
NGL's ($/bbl)	–	–	–	–

Brazil – 2012

	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
Average Production				
Light & Medium Oil (bbl/d)	158	144	92	873
Natural Gas (Mcf/d)	–	–	–	–
NGL's ($/bbl)	–	–	–	–
Selling Prices				
Light & Medium Oil ($/bbl)	99.53	90.74	89.03	98.96
Natural Gas ($/Mcf)	–	–	–	–
NGL's ($/bbl)	–	–	–	–
Royalties				
Light & Medium Oil ($/bbl)	12.68	10.96	9.62	13.22
Natural Gas ($/Mcf)	–	–	–	–
NGL's ($/bbl)	–	–	–	–
Production Costs				
Light & Medium Oil ($/bbl)	40.74	44.85	129.03	29.52
Natural Gas ($/Mcf)	–	–	–	–
NGL's ($/bbl)	–	–	–	–
Netbacks(1)				
Light & Medium Oil ($/bbl)	46.11	34.93	(49.62)	56.22
Natural Gas ($/Mcf)	–	–	–	–
NGL's ($/bbl)	–	–	–	–

(1) Netback is equal to revenue less royalty and production costs.

The following table discloses for each producing property and in total, the Corporation's production volumes for the period ended December 31, 2012 for each product type:

Production volumes for 2012 by property (net after royalty)

Net after royalty	Light/medium Oil Net bbl/d	Natural Gas Net mcf/d	NGL's Net bbl/d
Colombia			
Santana	170	–	–
Guayuyaco	232	–	–
Juanambu	848	–	–
Chaza – Costayaco	9,405	–	–
Chaza – Moqueta	1,682	–	–
Llanos 22-Ramiriqui	0	–	–
Guepaje	0	–	–
Guachiria	0	–	–
Garibay – Jilguero	613	–	–
Garibay – Melero	119	–	–
Sierra Nevada – Brillante	4	423	–
Sierra Nevada – La Pinta	3	–	–
Colombia total	13,075	423	–
Argentina			
Palmar Largo	145	–	–
El Vinalar	63	–	–
El Chivil	240	–	–
Surubi	1,032	–	–
Puesto Morales	1,382	3,679	–
Argentina total	2,861	3,679	–
Brazil			
Block 155	276	–	–
Brazil total	276	–	–
Total company	16,213	4,102	–

Directors

Jeffrey Scott
Chairman of the Board
President, Postell Energy Co. Ltd.

Ray Antony, CA
Corporate Director

Dana Coffield
President, Chief Executive Officer, Director

Gerald Macey
Corporate Director

Verne Johnson
President, KristErin Resources Inc.

Nicholas G. Kirton, FCA, ICD.D
Corporate Director

J. Scott Price
President, Prospect International Inc.

Executive Officers

Dana Coffield
President, Chief Executive Officer, Director

James Rozon
Chief Financial Officer

Shane O'Leary
Chief Operating Officer

David Hardy
General Counsel and Corporate Secretary

Foreign Subsidiary Managers

Rafael Orunesu
President, Gran Tierra Energy Argentina

Duncan Nightingale
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Material Requests

Gran Tierra Energy will supply a copy of this document, including financial statements and schedules, without charge, upon receiving a written request for these materials. Please submit your requests to Jason Crumley by email at info@grantierra.com or by mail to:

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Calgary, Alberta T2R 0E1, Canada

Gran Tierra Energy's filings are also available on a website maintained by the Securities and Exchange Commission at www.sec.gov and on SEDAR at www.sedar.com.

Annual General Meeting

The 2013 annual meeting of Shareholders will be held on June 26, 2013 at 3:00 pm MDT at:

Calgary Petroleum Club
319 Fifth Avenue SW,
Calgary, Alberta T2P 0L5, Canada

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