GRAN TIERRA ENERGY, INC.
Form 10-K
February 27, 2012

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

FORM 10-K

(Mark One)

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

For the year ended December 31, 2011

OR

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

For the transition period from _____________ to _____________

Commission File Number 001-34018

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

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

300, 625 11th Avenue SW
Calgary, Alberta, Canada T2R 0E1
(Address of principal executive offices, including zip code)

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

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.001 per share	NYSE Amex
	Toronto Stock Exchange

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold as of the last business day of the registrant's most recently completed second fiscal quarter was approximately $1.8 billon (including shares issuable upon exercise of exchangeable shares). Aggregate market value excludes an aggregate of 1,007,523 shares of common stock and 6,218,043 shares issuable upon exercise of exchangeable shares held by officers and directors on such date. Exclusion of shares held by any of these persons should not be construed to indicate that such person possesses the power, direct or indirect, to direct or cause the direction of the management or policies of the registrant, or that such person is controlled by or under common control with the registrant.

On February 21, 2012, the following numbers of shares of the registrant's capital stock were outstanding: 263,961,554 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 6,223,810 shares of Gran Tierra Goldstrike Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock; and one share of Special B Voting Stock, $0.001 par value, representing 8,512,707 shares of Gran Tierra Exchangeco Inc., which are exchangeable on a 1-for-1 basis into the registrant's Common Stock.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this report, to the extent not set forth herein, is incorporated by reference from the Registrant's definitive proxy statement relating to the 2012 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2011.

GRAN TIERRA ENERGY INC.

ANNUAL REPORT ON FORM 10-K

Year ended December 31, 2011

TABLE OF CONTENTS

		Page No.
PART I		
Item 1.	Business	6
Item 1A.	Risk Factors	27
Item 1B.	Unresolved Staff Comments	34
Item 2.	Properties	34
Item 3.	Legal Proceedings	35
Item 4.	Mine Safety Disclosures	35
PART II		
Item 5.	Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	37
Item 6.	Selected Financial Data	39
Item 7.	Management’s Discussion and Analysis of Financial Condition and Results of Operations	40
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	60
Item 8.	Financial Statements and Supplementary Data	60
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	85
Item 9A.	Controls and Procedures	85
Item 9B	Other Information	87
PART III		
Item 10.	Directors, Executive Officers and Corporate Governance	87
Item 11.	Executive Compensation	87
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	87
Item 13.	Certain Relationships and Related Transactions, and Director Independence	87
Item 14.	Principal Accounting Fees and Services	87
PART IV		
Item 15.	Exhibits, Financial Statement Schedules	88
SIGNATURES		88

Table of Contents

STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K, particularly in Item 1. "Business" and Item 7. "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 (the Securities Act) and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act). All statements other than statements of historical facts included in this Annual Report on Form 10-K 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", "expects", "anticipates", "intends", "estimates", "projects", "target", "goal", "plans", "objective", "should", or similar expressi variations on such 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 and because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, those set out in Part I, Item 1A "Risk Factors" in this Annual Report on Form 10-K. The information included herein is given as of the filing date of this Form 10-K with the Securities and Exchange Commission ("SEC") and, except as otherwise required by the federal securities laws, we disclaim any obligations or undertaking to publicly release any updates or revisions to any forward-looking statement contained in this Annual Report on Form 10-K to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any such statement is based.

GLOSSARY OF OIL AND TERMS

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

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

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 are paid 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.

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 inexpensive way of gathering data over large regions.

Seismic data is used by oil and natural gas companies as their 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 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 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. Such 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.

Table of Contents

Workover is a term used to describe remedial operations on a previously completed well to clean, repair and/or maintain the well for the purposes 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 (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

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

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

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

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

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

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 highest known oil (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

Table of Contents

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.

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.

(ii) 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.

In our discussion below, we refer to various oil fields and blocks. A more detailed discussion of these areas is set forth in Item 2 “Properties” of this Annual Report on Form 10-K.

PART I

Item 1. Business

General

Gran Tierra Energy Inc. together with its subsidiaries (“Gran Tierra” 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 on Form 10-K 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. During 2006, we acquired oil and gas producing and non-producing assets in Colombia, non-producing assets in Peru and additional properties in Argentina. During 2008, we increased our holdings in Colombia through the acquisition of Solana Resources Limited (“Solana”). In 2009, we added exploration blocks in

Colombia by converting our two Technical Evaluation Areas (“TEA”) to three exploration and exploitation blocks. In 2010, we added three blocks in Colombia through the Colombia Bid Round 10 and acquired a 55% interest in one block through a farm-in, acquired a 20% working interest in three additional blocks in Peru, acquired a 60% working interest in Block 95 in Peru and acquired a 70% working interest in four on-shore blocks in Brazil.

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 Item 7 “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for further details, which information is incorporated by reference here.

In 2011, we made capital expenditures of $327.6 million (after changes in non-cash working capital and net of proceeds from disposition of oil and gas properties), including drilling and acquisition expenditures of $224.6 million, facilities expenses of $38.0 million, geological and geophysical expenses of $50.8 million and other expenditures of $14.2 million. Additionally, the Petrolifera acquisition added $219.7 million to property, plant and equipment.

In 2011, we focused on development of producing fields and generation of exploration prospects in Colombia, including the acquisition of three blocks in the Petrolifera acquisition and the acquisition of a working interest in the Llanos 22 Block, subject to regulatory approval. In Argentina, we acquired seven additional blocks in the Petrolifera acquisition, maintained existing production and abandoned a natural gas wellbore the drilling of which had been started in late 2010. We continue to seek alternatives for the development of the natural gas project. In Peru, we continued to pursue Environmental Impact Assessment (“EIA”) approvals and drilled one exploration well, commenced seismic and preparations for drilling operations and further expanded our exploration portfolio through acquisition of working interests in three additional blocks. In Brazil, we became the operator of four blocks in the on-shore Recôncavo basin and commenced reporting production in June 2011. We also acquired a working interest in two offshore exploration blocks. Subsequent to year-end, we elected not to proceed to the second exploration phase in one block and received government approval for the other. Our farm-ins of a number of blocks in Colombia are still subject to governmental approvals.

Our acreage as of December 31, 2011, including acquisitions and excluding farm-outs which are subject to various government approvals, includes:

3.5 million gross acres in Colombia (3.0 million net) covering 21 exploration and production contracts, six of which are producing and 19 of which are operated by Gran Tierra (includes one block or 84,757 gross and 38,141 net acres subject to government approval, and five blocks for which working interest changes are subject to approvals);

1.4 million gross acres (0.8 million net) in Argentina covering twelve exploration and production contracts, eight of which are producing and ten of which are operated by Gran Tierra;

6.4 million gross acres (3.1 million net) in Peru covering five exploration licenses, all of which are frontier exploration areas and three of which are operated by Gran Tierra; and

0.8 million gross acres (0.1 million net) in Brazil covering six exploration blocks, one of which is producing and four of which are operated by Gran Tierra (includes two blocks or 754,118 gross and 96,240 net acres subject to government approval).

Table of Contents

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., whereby we will earn a 45% non-operated working interest in the Llanos-22 Block and CEPSAC will farm-in for a 30% working interest on the Piedemonte Norte Block. The completion of the transfer is subject to ANH approval.

We have interests in 21 blocks in Colombia, and are the operator in 19 blocks. The Guayuyaco, Santana, Chaza and Garibay blocks have producing oil wells. The Magangue Block and the Sierra Nevada Block each have one producing gas well.

Colombian royalties are established under law 756 of 2002. All discoveries made subsequent to the enactment of this law have the sliding scale royalty described below. Discoveries made before the enactment of this law have a royalty of 20%. The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) (“ANH”) contracts to which Gran Tierra is a party all have royalties that are based on a sliding scale described in law 756. This royalty works on an individual oil field basis starting with a base royalty rate of 8% for gross production of less than 5,000 barrels of oil per day. The royalty increases in a linear fashion from 8% to 20% for gross production between 5,000 and 125,000 barrels of oil per day, and is stable at 20% for gross production between 125,000 and 400,000 barrels of oil per day. For gross production between 400,000 and 600,000 barrels of oil per day the rate increases in a linear fashion from 20% to 25%. For gross production in excess of 600,000 barrels of oil per day the royalty rate is fixed at 25%.

Table of Contents

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

Our production from the Costayaco field is also 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 ANH and the sales price. As the exploration and production contracts stand currently, any new discoveries on ANH contracted blocks will also be subject to this additional royalty once the production from each new field exceeds five million barrels of cumulative production. The Moqueta discovery in the Chaza Block and the Jilguero discovery in the Garibay Block will both be subject to this additional royalty after each field produces five million barrels.

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 million barrels. For exploration and production contracts awarded in the 2010 Colombia bid round, including such contracts awarded to Gran Tierra, the high price royalty will apply once the production from the area governed by the contract, rather than any particular exploitation area designated under the contract, exceeds five million barrels of cumulative production. We expect that the criteria for the high price royalty will apply for subsequent bid rounds.

The Santana and Magangue blocks have a flat 20% royalty as those discoveries were made before 2002. The Guayuyaco and Rio Magdalena blocks have the sliding scale royalty but do not have the additional royalty.

In addition to these government royalties, Gran Tierra’s interests in the five blocks purchased from Argosy that we still hold (Santana, Guayuyaco, Chaza, Rio Magdalena and Mecaya) are subject to a third party royalty. Our interest in the Azar Block is also subject to the third party royalty. The additional interest in Guayuyaco and Chaza acquired by Gran Tierra on the acquisition of Solana is not subject to this third party royalty. On June 20, 2006, Gran Tierra entered into a participation agreement that would effectively compensate Crosby Capital, LLC for its share in certain Colombian properties. The compensation is in the form of an overriding royalty (“ORR”) that applies to production on any new discoveries made on historical properties within 10 years of the agreement date. The historical properties are Santana, Guayuyaco, Rio Magdalena, Talora (sold), Chaza, Primavera (relinquished), Mecaya and Azar. The overriding royalty starts with a 2% rate on working interest production less government royalties. After a prescribed threshold is reached, Crosby reserves the right to convert the ORR to a Net Profit Interest (“NPI”). This NPI is based on 7.5% on working interest production less government royalties and operating and overhead costs and reaches a maximum rate of 10%. On certain pre-existing fields, Crosby does not have the right to convert its ORR to a NPI. The ORR and NPI are calculated on Gran Tierra’s working interest production after royalties. In addition, there is a conditional overriding royalty that applies only to the pre-existing fields. Crosby and Gran Tierra disagree as to how NPI is calculated and engaged in arbitration in December 2011. The arbitrator is expected to issue a decision in March 2012. Gran Tierra does not consider it probable that a loss will be incurred.

Chaza Block

The Chaza Block covers 46,533 gross acres and is governed by the terms of an Exploration and Exploitation Contract with ANH, which was signed June 27, 2005. We are the operator and hold a 100% participation interest. 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.

Upon completion of the sixth exploration phase in June 2011, 50% of the block was relinquished to ANH resulting in the current acreage of 46,533. We applied and were granted an additional exploratory program allowable under our contract which extended the exploration phase of the contract to June 26, 2013. The additional exploration phase requires 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 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 the first quarter of 2011, we drilled and completed the Costayaco -12 and Costayaco -13 development wells in the Costayaco field. We drilled and completed the Costayaco -14 development well in the third quarter of 2011. In the Moqueta field, we completed three development wells, Moqueta-4, Moqueta-5 and Moqueta -6 during 2011. We also drilled the Canangucho-1 exploration well which was plugged and abandoned in the first quarter of 2011. In the fourth quarter of 2011, the Pacayaco -1ST1 oil exploration well reached total depth with only non-commercial hydrocarbons present and was plugged and abandoned in 2012.

During 2011, we commenced construction of facilities at the Moqueta field and completed the six-inch diameter, eight kilometer pipeline connecting the Moqueta and Costayaco infrastructure. A parallel four-inch gas line was also completed that will be used to transport gas or water from Costayaco to Moqueta for anticipated gas injection for pressure support.

In 2012, we plan to drill six gross development wells. In the Costayaco field, we plan to drill two additional water injector wells and two production wells. In the Moqueta field, we plan to drill one development well, which could be used as an oil producer or water injector depending on the well results, and a further water injector well. In addition, electrical works, water injection facilities and a production battery are planned for both Costayaco and Moqueta. We also plan to acquire 120 square kilometers of 3D seismic for Moqueta in 2012.

Guayuyaco Block

The Guayuyaco Block contract was signed in September 2002 and covers 52,366 gross acres, which includes the area surrounding the producing fields of the Santana contract area. The Guayuyaco Block is governed by an Association Contract with Ecopetrol. We are the operator and have a 70% participation interest, with the other 30% held by Ecopetrol. Ecopetrol has the option to back-in to a 30% participation interest in any other new discoveries in the block.

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 expires in 2030. We have completed all of our obligations in relation to the contract. The property will be returned to the government upon expiration of the production contract and we are not obligated to perform remediation work.

Table of Contents

In 2011, we drilled the Juanambu-3 development well as a producing well, purchased pumping equipment and acquired the Verdayaco prospect 3D seismic. In 2012, we plan to drill the Verdayaco-1 oil exploration well.

Garibay Block

Solana acquired the Garibay Block in October 2005. The block covers 75,936 gross acres and we have a non-operated working interest of 50%. CEPSAC has the remaining 50% and is the operator. The block is held under an ANH exploration and exploitation contract. The sixth exploration phase expired in October 2011, but we were granted an additional exploration phase, which expires October 24, 2013. There is an obligation to drill one exploration well in this exploration phase.

In 2011, the Melero-1 exploration well was drilled and completed and resulted in an oil discovery. The Jilguero-2 development well was also completed as a producing well in October 2011. We also upgraded facilities and completed civil works. In 2012, together with CEPSAC, we plan to drill the Bordon-1 oil exploration well.

Llanos 22 Block

In 2011, we entered into farmout agreements with CEPSAC. We will earn a 45% non-operated working interest in the Llanos-22 Block (CEPSAC will retain 55% and operatorship) and CEPSAC will farm-in for a 30% working interest on the Piedemonte Norte Block. Under the terms of these agreements, in addition to the swap of the 30% working interest in the Piedemonte Norte block, we will pay $1.5 million towards historical costs and a partial carry on the current well being drilled. The completion of the transfer is subject to ANH approval. The block is held under an ANH exploration and exploitation contract and covers 84,757 gross acres.

Phase one of two phases of the exploitation contract will end on May 4, 2012. In 2011, our partner began drilling the Ramiriqui-1 oil exploration well. The drilling of the Ramiriqui-1 oil exploration well will satisfy the final work obligation of this phase of the contract. The seismic obligation had been completed by our partner prior to the farm out deal. Phase two requires two exploration wells to be drilled or one exploration well and relinquishment of 50% of the block prior to May 4, 2015. In 2012, we are awaiting ANH approval of the farm-in agreement and are evaluating the results of the exploration well.

Santana Block

The Santana Block contract was signed in July 1987 and covers 1,119 gross acres 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 7 million barrels of oil produced, Ecopetrol had the right to back into a further 15% working interest, which it exercised, for a total ownership of 65%. The production contract expires in 2015, at which time the property will be returned to the government and we are not obligated to perform remediation work.

In 2011, we performed minor facilities maintenance. In 2012, no significant capital expenditures are planned.

Azar Block

We acquired an 80% interest in the Azar Block through a farm-in agreement entered into in late 2006. In mid-2007, we entered a farm-out agreement to transfer 50% of our working interest. This farm-out is subject to ANH approval. This exploration block covers 47,226 gross acres and we are the operator. The block is held under an ANH contract.

We are now in the fifth exploration phase which carries a commitment to drill one exploration well. That phase originally would have expired on February 11, 2012, but we have applied for a four month extension, and if approved, plan to drill the La Vega Este-1 well in the first half of 2012. There is one more exploration phase that follows, which lasts 12 months and includes an obligation to drill one exploration well. The current exploration phase of the contract expires in February 2013, however, if the extension is approved we would expect the contract expiry to change accordingly. The exploitation phase expires 24 years after commerciality 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 2011, we conducted environmental studies. In 2012, we plan to drill the La Vega Este-1 oil exploration well, subject to the receipt of the exploration phase extension.

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 in northwest Colombia and covers 178,154 gross acres. We are the operator of the block with a 100% working interest. The block is held under an ANH exploration and exploitation contract and a third party has a 1% ORR on the block. The third development phase was completed on December 28, 2011 and our commitment was fulfilled by the drilling of the Brillante SE-2 development well. We relinquished 15% of the block on December 28, 2011, as part of the third phase contract commitments. We are in phase four of six, which ends on December 28, 2012, and are required to drill one additional development well for this phase. The final exploration phase is scheduled to end in June 2014 and the exploitation phase would expire 24 years after commerciality if a discovery is approved.

In 2011, we drilled the Brillante SE-2 development well which was plugged and abandoned. We also completed a 275 square kilometer 3D seismic survey, including approximately 222 square kilometers of data in the Sierra Nevada license and 53 square kilometers in the Magdalena license. In 2012, we plan to drill the Brillante-3 natural gas delineation well.

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 in northwest Colombia and covers 594,803 gross acres. We are the operator of the block with a 100% working interest. The block is held under an ANH exploration and exploitation contract and a third party has a 1% ORR on the block. Phase one of the exploration contract was completed on May 1, 2011 and we fulfilled our commitment by the drilling of the San Angel-1001 exploration well. We are in phase two of six phases, which ends on May 1, 2012. Our obligation to complete 52 square kilometers of 3D seismic was satisfied by the Brillante 3D seismic survey. The third exploration phase will expire on May 1, 2013 and will require one exploration well to be drilled. The final exploration phase is scheduled to end in February 2016 and the exploitation phase would expire 24 years after commerciality if a discovery is approved.

Table of Contents

In 2011, we drilled the San Angel-1001 natural gas exploration well which was plugged and abandoned. In 2012, no significant capital expenditures are planned.

Piedemonte Norte Block

In June 2009, we completed the conversion of our TEAs in the Putumayo Basin to blocks with ANH exploration and exploitation contracts. The Piedemonte Norte Block covers 78,742 gross acres and is held 100% by Gran Tierra. In the fourth quarter of 2011, we farmed out 30% of the block to CEPSAC, subject to ANH approval. This asset swap was in connection with the Llanos-22 Block farm-in. We will retain operatorship of the Piedemonte Norte Block. The first exploration phase was to expire in June 2011, and required the acquisition, processing and interpretation of 70 kilometers of 2D seismic; however, the block is under suspension pending receipt of an environmental permit. This contract has a total of six exploration phases and the exploration phase of the contract expires in December 2015, however, since this block is under suspension the contract expiration will likely be delayed. The exploitation phase would expire 24 years after commerciality if a discovery is approved.

In 2011, there were no significant capital expenditures. In 2012, we plan to acquire 50 kilometers of 2D seismic, subject to release of the block from suspension.

Piedemonte Sur Block

The Piedemonte Sur Block was part of the Putumayo West A TEA and became an exploration block with an ANH exploration and exploitation contract in June 2009. The Piedemonte Sur Block covers 73,898 gross acres and is held 100% and operated by Gran Tierra. We are in a unified phase two and three of six exploration phases in the contract. This phase requires the acquisition of 55 kilometers of 2D seismic and the drilling of one exploration well by December 2012. The exploration phase ends in December 2015, and the exploitation phase would expire 24 years after commerciality if a discovery is approved.

In 2011, we completed the Taruka-1 exploration well, which was plugged and abandoned. The drilling of this well satisfied our phase one commitment. In 2012, we plan to acquire 51 kilometers of 2D seismic which, together with seismic activity in prior years, will satisfy our unified phase two and three seismic obligation.

Rumiyaco Block

The Rumiyaco Block was part of the Putumayo West B TEA and became an exploration block with an ANH exploration and exploitation contract in June 2009. Rumiyaco covers 82,624 gross acres and is held 100% and operated by Gran Tierra. We are in a unified phase two and three of six exploration phases in the contract. We partially fulfilled the unified phase two and three contract work obligations with the drilling of the Rumiyaco-1 exploration well in 2011. We are obligated to complete 50 square kilometers of 3D seismic or drill an exploratory well prior to September 2012. The exploration phase ends in December 2015 and the exploitation phase would expire 24 years after commerciality of a discovery is approved.

In 2011, we drilled the Rumiyaco-1 exploration well which was plugged and abandoned. In 2012, we will assess the well results from Rumiyaco-1 but currently have no capital expenditures planned.

Magangué Block

Solana acquired the Magangue Block in October 2006. It is held pursuant to an Ecopetrol Association Contract and covers 20,647 gross acres. We are the operator of the block with a 42% working interest and our partner Ecopetrol has the remaining 58%. This block contains the producing Guepaje gas field. The exploration phase for this block is over and no further work commitments exist on this block. The contract expires in 2017.

In 2011, we completed minor facilities upgrades. In 2012, no significant capital expenditures are planned.

Mecaya Block

The Mecaya exploration and exploitation contract with the ANH was signed June 2006. The Mecaya contract area covers 74,128 gross acres in southern Colombia in the Putumayo Basin. We are the operator and have a 15% participation interest and two partners have 55% and 30% interests, respectively. We are in a unified phase one and two of four exploration phases in the contract and are obligated to complete 52 square kilometers of 3D 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. There are two more exploration phases following, each of which are 12 months in duration. The third phase has an obligation to acquire seismic data, and the fourth phase has the obligation to drill one exploration well. The exploitation phase for this contract expires 24 years after commerciality is approved for any discovery. The property will be returned to the government upon expiration of the production contract.

In 2011, there were no significant capital expenditures. In 2012, we plan to conduct environmental assessments.

Cauca 6 Block

We were awarded the Cauca 6 Block in June 2010 in the Colombia Bid Round 10. The block covers 571,098 gross acres in the Cauca basin and we hold a 100% working interest as operator. The block is held under an ANH TEA contract. The initial nine month phase of community consultation was completed in 2011. The exploration phase of the contract requires the acquisition of 200 kilometers of 2D seismic and the drilling of one stratigraphic well by December 2014. This TEA contract would then be converted into an exploration and exploitation contract.

In 2011, we conducted surface and subsurface geological studies. In 2012, we plan to acquire aeromagnetic and aerogravity surveys as well as further geological studies.

Cauca 7 Block

We were awarded the Cauca 7 Block in June 2010 in the Colombia Bid Round 10. The block covers 785,452 gross acres in the Cauca basin and we a hold a 100% working interest as operator. The block is held under an ANH TEA contract. The initial nine month phase of community consultation was completed in 2011. The exploration phase of the contract requires the acquisition of 250 kilometers of 2D seismic and the drilling of one stratigraphic well by December 2014. This TEA would then be converted into an exploration and exploitation contract.

In 2011, we conducted surface and subsurface geological studies. In 2012, we plan to acquire aeromagnetic and aerogravity surveys as well as further geological studies.

Putumayo 10 Block

We were awarded the Putumayo 10 Block in June 2010 in the Colombia Bid Round 10. The block covers 114,096 gross acres in the Putumayo basin and we hold a 100% working interest as operator. The block is held under an ANH exploration and exploitation contract. The initial six month phase of community consultation was completed in 2011. We are in the first of two exploration phases of the contract. This phase requires the acquisition of 73 kilometers of 2D seismic and the drilling of two exploration wells by September 2014. The exploration phase ends in September 2017 and the exploitation phase would expire 24 years after commerciality of a discovery is approved.

In 2011, there were no significant capital expenditures. In 2012, we plan to acquire 100 kilometers of 2D seismic.

Putumayo 1 Block

We acquired a 55% operated 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 ANH exploration and exploitation contract. We are in the first of two exploration phases of the contract. This phase requires the acquisition of 159 square kilometers of 3D seismic and one exploration well to be drilled by September 2012. The exploration phase ends in September 2015 and the exploitation phase would expire 24 years after commerciality of a discovery is approved.

In 2011, we initiated the acquisition of 120 square kilometers of 3D seismic. In 2012, we plan to complete the seismic program which commenced in 2011 and acquire 227 square kilometers of 3D seismic.

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 have one partner with the remaining 50%. The block is held under an ANH exploration and exploitation contract and a third party has a 1% ORR on the block. We are in the third phase of six exploration phases of the contract. This phase requires one exploration well to be drilled by March 2012; however, the contract is suspended pending the issuance of an environmental license. The exploration phase ends in December 2014 and the exploitation phase would expire 24 years after commerciality of a discovery is approved.

In 2011, we conducted environmental studies. In 2012, no significant capital expenditures are planned.

Catguas Block (Catguas A & Catguas B)

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. We relinquished 15% of this block during 2011. The block is held under an ANH exploration and exploitation contract. We have a 100% working interest in these blocks, however, in December 2005, Solana and its partner signed a participation agreement whereby they defined the areas A & B and distributed them between the companies in the block. Catguas A covers 74,119 gross acres and Catguas B covers 256,235 gross acres. 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 pending approval by ANH.

We are in a unified phase two and three of six exploration periods in the contract. This phase was to expire in May 2007; however, the block contract is in suspension by ANH as a result of force majeure. This period has an obligation to drill three exploratory wells or two exploratory wells and one re-entry, plus 50 square kilometers of 3D seismic. The two subsequent exploration periods are 12 months each in length and require the drilling of one exploration well. The exploitation phase would end 24 years from any declaration of a commercial discovery.

In 2011, there was no activity on this block, and no activity is planned for 2012.

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 2010, we relinquished 50% of the area in the block. We are the operator of the block and hold a 70% working interest, with our partner holding a 30% working interest. An agreement to transfer a further interest to our partner to reduce our working interest to 30.8% is pending Ecopetrol approval. The exploration phase of the contract expired in September 2010 and the production period will expire in 2030 at which time the property will be returned to the government. As a result, there will be no reclamation costs. According to the terms of the Association Contract, Ecopetrol may back-in for a 30% participation interest in any discoveries on the block upon commercialization.

In 2011, there were no significant capital expenditures and no significant capital expenditures are planned for 2012.

Table of Contents

Oil and Gas Properties – Argentina

Our Argentina properties are located in the Noroeste Basin in northern Argentina and Neuquen Basin in central Argentina.

In September 2005, we entered Argentina through the acquisition of a 14% interest in the Palmar Largo joint venture, and a 50% interest in each of the Nacatimbay and Ipaguazu blocks. In 2006, we purchased additional properties in Argentina, including the remaining 50% interest in Nacatimbay and Ipaguazu, a 50% interest in El Vinalar, a 100% interest in El Chivil, Surubi and Santa Victoria, and a 96.6% interest in Valle Morado. In 2009 we relinquished our rights to the Nacatimbay Block and, in 2011, we relinquished our interest in the Ipaguazu Block.

In March 2011, we acquired Petrolifera which added seven blocks in the Neuquen basin: Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Vaca Mahuida, Puesto Guevara and Gobernador Ayala II. The Rinconada Sur Block is part of the Puesto Morales concession. We relinquished our interest in the Gobernador Ayala II Block during 2011.

The Puesto Morales, Puesto Morales Este, Rinconada Norte, Rinconada Sur, Surubi, El Chivil, Palmar Largo and El Vinalar blocks have producing oil wells and Puesto Morales also has producing gas wells.

Royalties in Argentina are based on a federal crown royalty plus an additional provincial turnover tax. The federal crown royalty ranges from 12% to 24%. The provincial turnover tax ranges from 1.5% to 3% on our blocks.

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, has an exploitation phase of 25 years, and a possible five year extension to a maximum of 30 years. We have no work outstanding commitments on this block.

In 2011, we commenced drilling two development wells and a well workover program and carried out upgrades to facilities. One of the development wells was completed in 2011 and one will be completed in 2012. In 2012, we also plan to drill eight development wells, which include injectors and enhanced oil recovery pilot projects and continue the workover program and 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, has an exploitation phase of 25 years, and a possible five year extension to a maximum of 30 years. We have no outstanding work commitments on this block.

In 2011, we started drilling one development well. In 2012, we plan to complete the 2011 well, drill two exploration wells and complete geological and geophysical subsurface work.

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 it has an exploitation phase of 25 years, and a possible five year extension to a maximum of 30 years. We have no outstanding work commitments on this block.

In 2011, we drilled two producing development wells. In 2012, regular field maintenance, workover activities and facilities upgrades are planned.

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 65%. This is an exploitation concession which expires January 21, 2016. There was an obligation to drill three exploration wells which was satisfied in 2011. We have no outstanding work commitments on this block.

In 2011, our partner commenced drilling four gross exploration wells. Two wells were completed in 2011, which resulted in an oil discovery, and two were in progress at year-end. In 2012, we will continue evaluating the block and will perform facilities upgrades.

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 expires in 2026 and we have no outstanding work commitments on this block.

In 2011, we performed regular maintenance and workover activities at the Proa-1 discovery well and site preparation work for the Proa-2 development well and associated facilities. In 2012, we commenced drilling the Proa-2 development well and will perform regular maintenance and workover activities.

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 Chivil field was discovered in 1987. The contract for this field expires in 2015 with the option for a ten year extension.

Regular field maintenance and workover activities were performed in 2011 and are planned for 2012.

Palmar Largo Block

We own a 14% non-operated working interest in the Palmar Largo Block, which we purchased in September 2005. Three partners hold the remaining 86% working interest. The Palmar Largo joint venture block covers 186,441 gross acres. During 2011, we relinquished 45.4% of this block. This asset is comprised of several producing oil fields in the Noroeste Basin and is subdivided into three sub-blocks including Balbuena Este. The Palmar Largo Block rights expire in 2017, but provide for a ten-year extension. We have no outstanding work commitments on this block. On expiry of the block rights, ownership of the producing assets will revert to the provincial government.

In 2011, one gross development well was drilled. Regular field maintenance and workover activities were also performed in 2011 and are planned for 2012.

El Vinalar Block

In June 2006, we acquired a 50% operating working interest in the El Vinalar Block, which covers 61,035 gross acres. The El Vinalar rights expire in 2016 with a possible ten year extension. We do not have any outstanding work commitments on this block. On expiry of the block rights, ownership of the producing assets will revert to the provincial government.

In 2011, we performed regular field maintenance and workover activities. In 2012, no significant capital expenditures are planned.

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.The previous owners had the option to back-in for an 18% working interest under certain circumstances; however, we purchased this from the owners and eliminated this option during 2010. Valle Morado 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 3D 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 outstanding commitments on this block. In 2012, we plan to conduct additional geological and geophysical studies, minor facilities upgrades and civil engineering work.

Santa Victoria Block

We purchased the Santa Victoria Block in 2006. Santa Victoria covers 516,942 gross acres. We have a 50% working interest and are the operator. In 2011, we relinquished 50% of the block as a condition to enter into the second phase. We also farmed out 50% of our working interest to Apache Corporation. The contract’s first exploration phase expired in December 2010; however, we received a 90 day extension to March 29, 2011. During the first phase, a 3D seismic survey was acquired to fulfill the first phase commitment and the extension was used to complete the seismic interpretation. We are in the second of three exploration phases of the contract. This phase requires either one exploration well to be drilled or 720 units of work ($3.6 million) to be completed by March 2013. The exploration phase ends in March 2014. In 2012, we will evaluate the potential to drill a gas exploration well.

Table of Contents

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 have a 25% operated working interest and our three partners share the remaining 75% working interest. After three gas discoveries in 2010, an exploitation concession was requested and we are awaiting 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 outstanding work commitments on this block.

In 2011, there were no significant capital expenditures and no significant capital expenditures are planned for 2012.

Puesto Guevara Block

We acquired our interest in the Puesto Guevera Block through the Petrolifera acquisition in March 2011. The Puesto Guevera block covers 165,488 gross acres. We are the operator of the block with a 100% working interest. We are in the first exploration phase which requires the drilling of one exploration well by April 24, 2012. We are currently evaluating the geological/economical potential of the block. If no potential exists, we plan to relinquish the block and pay a penalty of $0.6 million. There are two additional optional exploration phases which would expire in April 2015.

Ipaguazu Block

We acquired a 100% working interest in the Ipaguazu Block through two transactions. We purchased a 50% working interest in September 2005 and we purchased the remaining 50% working interest in November 2006. In April 2010, production operations at the Ipaguazu-1 well were suspended due to low well productivity. We received approval for relinquishment of this block in 2011.

Gobernador Ayala II Block

We acquired our interest in the Gobernador Ayala II Block through the Petrolifera acquisition in March 2011. We relinquished this block in 2011.

Oil and Gas Properties - Peru

We entered Peru in 2006 through the award by the Government of Peru of two frontier exploration blocks, Block 122 and Block 128, in the Maranon Basin. In September 2010, we acquired a 20% non-operated working interest in three blocks in the Maranon Basin. These three blocks, Block 123, Block 124, and Block 129 are adjacent to Block 122 and Block 128. In December 2010, we further increased our acreage position in the Maranon Basin in Peru by acquiring a 60% working interest in Block 95.

In March 2011, we acquired Petrolifera which added three blocks in the Ucayali Basin in Peru: Block 106, Block 107 and Block 133. Prior to the close of the acquisition, Petrolifera, in consultation with Gran Tierra, notified PeruPetro of the intention not to proceed to the next exploration phase in Block 106. Accordingly, the Block 106 license agreement was terminated in April, 2011.

On January 17, 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block and operatorship to Gran Tierra Energy.

Table of Contents

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 barrels of oil per day is assessed a royalty of 5%, for production between 5,000 and 100,000 barrels of oil per day there is a linear sliding scale between 5% and 20%. Production over 100,000 barrels per day has a flat royalty of 20%. This royalty structure applies to all blocks in Peru that we have an interest in.

Block 95

In December 2010, we acquired a 60% working interest in Block 95. Block 95 has a total area of 1,274,399 gross acres. We are the operator of Block 95. A drilling location has been identified for the first exploration well on Block 95, with civil construction initiated in the third quarter of 2011. Drilling is expected to be undertaken in 2012, pending regulatory approvals. An oil field has already been discovered on Block 95, with the discovery well drilled in 1974 flowing 807 BOPD naturally without pumps. The new exploration well is expected to further delineate this field and explore deeper reservoir horizons not penetrated by the discovery well. We are in the third phase of six of the contract, which has been delayed as a result of force majeure. Once force majeure ends, we plan to apply to extend the current phase to provide sufficient time to complete the well commitment.

Block 123, Block 124 and Block 129

In September 2010, we acquired a 20% working interest in Block 123, Block 124, and Block 129. We relinquished our interest in Block 124 during 2011. The two remaining blocks have a total area of 3,491,240 gross acres and Burlington Resources Peru Limited (a wholly owned subsidiary of ConocoPhillips) is the operator of these blocks. We are in the third phase of five, which expires November 29, 2012 for Block 123 and February 26, 2013 for Block 129. This phase requires the acquisition of seismic totalling 504 kilometers over the 2 blocks.

In 2011, 910 kilometers of 2D seismic was acquired on these blocks. In 2012, we plan to acquire 567 kilometers of 2D seismic.

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. A third party has a 3% ORR on the block. We are in the third exploration phase, which ends on May 24, 2012, and have fulfilled our obligations for this phase. The fourth and final phase is from May 25, 2012 to May 24, 2013, during which we are required to drill one exploration well.

In 2011, we conducted environmental studies and advanced permitting for drilling. In 2012, we plan to complete a 390 kilometer infill 2D seismic program and begin construction of a drilling platform.

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. This block has a royalty of 20% to 25%. We are in the second exploration phase of four, which ends on February 14, 2013. We are required to acquire 150 kilometers of 2D seismic and then relinquish 20% of the block at the end of phase two. The exploration phase expires in August 2016.

In 2011, we conducted environmental studies. In 2012, we plan to acquire airborne gravity and magnetic surveys and conduct EIAs.

Block 122 and Block 128

We were awarded two exploration blocks in Peru in the last quarter of 2006, Blocks 122 and 128, under a license contract for the exploration and exploitation of hydrocarbons. In 2011, we relinquished our interests in Block 122 and Block 128.

In 2011, we drilled the Kanatari -1 exploration well on Block 128 which was plugged and abandoned.

Table of Contents

Oil and Gas Properties - Brazil

We entered Brazil in 2009 with the opening of a business development office. In August 2010, we acquired a 70% working interest in four exploration blocks in the Recôncavo Basin. Final approval from the Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP") was received on June 15, 2011 and we became the operator of these blocks effective from that date. With the exception of one block which has a producing well, the remaining blocks are unproved properties. First production contribution from the producing block was recorded in June 2011. In January 2011, Gran Tierra opened an office in Salvador, Brazil to manage the field operations for the Recôncavo Basin blocks.

In September 2011, we announced farmout 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. At the time of entering into the farmout agreement, Block BM-CAL-10 was in the first exploration phase. In accordance with the terms of the Block BM-CAL-10 farmout agreement, we gave notice to Statoil that we will 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 Block BM-CAL-10 farmout agreement has terminated and we will not receive any interest in Block BM-CAL-10. We received ANH approval for Block BM-CAL-7 in the first quarter of 2012.

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. These four blocks cover 27,075 gross acres. We are the operator of these blocks with a 70% working interest. All four blocks are in the second exploratory phase of the contracts which expires in the fourth quarter of 2013. The second exploratory phase requires the drilling of an exploration well on each block.

In 2011, we drilled two gross exploration wells, 1-GTE-01-BA and 1-GTE-02-BA, on Blocks REC-T-142 and REC-T-129, respectively and an appraisal well, 3-GTE-03-BA on Block REC-T-155, was spud in December 2011. Drilling of the 1-GTE-01-BA vertical pilot exploration well was completed in November 2011. Core samples were acquired from the prospective reservoir section of the pilot well and we plan to drill a horizontal sidetrack in mid-2012 to test the productivity of light oil sandstone reservoir targets. Drilling of the 1-GTE-02-BA exploration well is suspended while plans are finalized for drilling a horizontal leg in mid-2012. Drilling of the 3-GTE-03-BA delineation well began on December 1, 2011 and drilling of the 3-GTE-04-BA development well began on January 8, 2012 to further develop the existing discovery on Block REC-T-155. Oil bearing reservoir intervals were encountered and we are moving forward with plans to complete and place this well on production.

The drilling of these wells satisfied each block’s first exploratory phase commitment. We also completed the acquisition of 35 square kilometers of 3D seismic data on Block REC-T-224, which fulfilled our first phase commitment on that block. In 2012, we plan to complete the 3-GTE-03-BA and 3-GTE-04-BA appraisal wells on Block REC-T-155. We also plan to drill two exploration wells, 1-GTE-5-BA and 1-GTE-6-BA, on Block REC-T-155 and Block REC-T-142.

Table of Contents

BM-CAL-7 Block

The BM-CAL-7 Block is located in the Camamu Basin, offshore Bahia, Brazil and covers 337,561 gross acres. ANP approval was received in the first quarter of 2012. We have a 10% non-operated working interest in the block. BM-CAL-7 is in the first of two exploration phases. This phase ends in November 2013. The first exploration phase requires the drilling of one exploration well and the acquisition of 1,366 square kilometers of 3D seismic by 2013. Our partner had previously satisfied the seismic commitment and, in 2011, we purchased the existing 3D seismic program. We are awaiting ANP approval to continue the 3D seismic survey during 2012.

BM-CAL-10 Block

The BM-CAL-10 Block is located in the Camamu Basin, offshore Bahia, Brazil and covers 416,557 gross acres. In September of 2011, we announced a farmout agreement with Statoil pursuant to which, subject to ANP approval, we would receive an assignment from Statoil of a non-operated 15% working interest in the block. At the time of entering into the farmout agreement, Block BM-CAL-10 was in the first exploration phase. The ANP has announced the 1-STAT-7-BAS exploration well drilling has been completed after reaching a total measured depth of 3,651 meters. Contractually, we are restricted from discussing the well results. In accordance with the terms of the farmout 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 farmout agreement has terminated and we will not receive any interest in Block BM-CAL-10.

Reserves

The following table sets forth our reserves as of December 31, 2011. The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. “Risk Factors”. The reserve estimation process requires us to use significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each property. Therefore the accuracy of the reserve estimate is dependent on the quality of the data, the accuracy of the assumptions based on the data, and the interpretations and judgment related to the data.

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 audited 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.

Reserves Category	Reserves Liquids* (Mbbl)	Reserves Natural Gas (MMcf)
PROVED		
Developed:		
Colombia	20,899	13,927
Argentina	1,918	3,351
Brazil	54	-
Undeveloped		
Colombia	4,526	713
Argentina	3,226	331
Brazil	299	-
TOTAL PROVED	30,922	18,322
PROBABLE		
Developed		
Colombia	3,752	3,037
Argentina	576	522
Brazil	57	-
Undeveloped		
Colombia	2,161	18,118
Argentina	2,813	4,039
Brazil	1,130	-
TOTAL PROBABLE	10,489	25,716
POSSIBLE		
Developed		
Colombia	6,780	2,828
Argentina	873	1,026
Brazil	64	-
Undeveloped		
Colombia	2,969	69,198
Argentina	4,969	43,457
Brazil	1,971	-
TOTAL POSSIBLE	17,626	116,509

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

Table of Contents

Proved Undeveloped Reserves

At December 31, 2011 we had total proved undeveloped reserves NAR of 8.2 MMBOE (December 31, 2010 - 4.1 MMBOE), including 4.6 MMBOE in Colombia (December 31, 2010 – 3.9 MMBOE), 3.3 MMBOE in Argentina (December 31, 2010 – 0.2 MMBOE) and 0.3 MMBOE in Brazil (December 31, 2010 – nil). Approximately 38% 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 37% and 15% of proved undeveloped reserves are in our Moqueta and Costayaco fields in Colombia. There was no material change in these amounts during 2011. All of our proved undeveloped reserves are scheduled for development within five years. We have an active exploration program and spent $44.0 million on exploratory items in 2011, including seismic and drilling. We drilled 12 net exploration wells in 2011. Our 2012 work program includes $152 million for exploration activities.

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

	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)
WTI +10%						
Colombia	25,270	13,479	5,952	22,316	9,663	72,026
Argentina	5,144	3,682	2,960	4,561	6,271	44,483
Brazil	354	-	1,208	-	2,075	-
Total	30,768	17,161	10,120	26,877	18,009	116,509
WTI – 10%						
Colombia	25,499	13,479	5,989	22,316	9,970	72,026
Argentina	5,144	3,682	2,960	4,561	6,271	44,483
Brazil	341	-	1,158	-	1,986	-
Total	30,984	17,161	10,107	26,877	18,227	116,509

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

The price cases presented involve changes to the WTI price – first with a 10% increase, the second with a 10% decrease. Natural gas prices are not affected by WTI, 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 WTI 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.

Table of Contents

Production Revenue and Price History

Certain information concerning oil and natural gas production, prices, revenues (net of all royalties) and operating expenses for the three years ended December 31, 2011 is set forth in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and in the Unaudited Supplementary Data provided following our Financial Statements in Item 8, which information is incorporated by reference here. 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 development and exploration drilling activity for the past three years. Wells labeled as “In Progress” were in progress as of December 31, 2011.

	2011		2010		2009	
	Gross	Net	Gross	Net	Gross	Net
Colombia						
Exploration						
Productive	1.00	0.50	4.00	3.50	-	-
Dry	6.00	6.00	1.00	1.00	2.00	0.70
In Progress	1.00	0.44	3.00	2.43	1.00	1.00
Development						
Productive	8.00	7.20	2.00	1.70	3.00	3.00
Dry	1.00	1.00	-	-	1.00	1.00
In Progress	-	-	2.00	2.00	1.00	0.70
Total Colombia	17.00	15.14	12.00	10.63	8.00	6.40
Argentina						
Exploration						
Productive	2.00	0.70	-	-	-	-
Dry	1.00	1.00	-	-	-	-
In Progress	2.00	0.70	-	-	-	-
Development						
Productive	3.00	3.00	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	2.00	2.00	1.00	0.93	-	-
Total Argentina	10.00	7.40	1.00	0.93	-	-
Brazil						
Exploration						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	2.00	1.40	-	-	-	-
Development						
Productive	-		-	-	-	-
Dry	-	-	-	-	-	-
In Progress	1.00	0.70	-	-	-	-
Total Brazil	3.00	2.10	-	-	-	-
Peru						
Exploration						
Productive	-	-	-	-	-	-

Dry	1.00	1.00	-	-	-	-
In Progress	-	-	-	-	-	-
Development						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	-	-	-	-	-	-
Total Peru	1.00	1.00	-	-	-	-
Total	31.00	25.64	13.00	11.56	8.00	6.40

Table of Contents

As at February 21, 2012, the results of wells in progress at December 31, 2011 are as follows:

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
Colombia	-	-	-	-	1.00	0.44
Argentina	2.00	2.00	-	-	2.00	0.70
Brazil	-	-	-	-	3.00	2.10
Peru	-	-	-	-	-	-
Total	2.00	2.00	-	-	6.00	3.24

Well Statistics

The following table sets forth our producing wells as of December 31, 2011.

	Oil Wells		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia (1)	39.00	29.40	2.00	1.40	41.00	30.80
Argentina (1)	115.00	89.80	7.00	7.00	122.00	96.80
Brazil	1.00	0.70	-	-	1.00	0.70
Peru	0.00	0.00	-	-	0.00	0.00
Total	155.00	119.90	9.00	8.40	164.00	128.30

(1) Includes 4.0 gross and net water injector wells in Colombia and 32.0 gross and 20.68 net water injector wells in Argentina.

Developed and Undeveloped Acreage

The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2011.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia	374,756	308,375	3,014,524	2,833,440	3,389,280	3,141,815
Argentina	469,339	250,984	964,180	515,709	1,433,519	766,693
Peru	-	-	6,367,807	3,065,055	6,367,807	3,065,055
Brazil	5,786	4,051	21,289	14,902	27,075	18,953
Total	849,881	563,410	10,367,800	6,429,106	11,217,681	6,992,516

(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 136,869 net acres in Colombia and an increase of 754,118 gross (96,240 net) acres in Brazil.

Our net developed acreage in Colombia includes acreage in the Santana Block (less than 1%); the Magangue Block (less than 1%); the Guayuyaco Block (1.2%); the Garibay Block (1.2%); the Chaza Block (1.5%); and the Sierra Nevada Block (5.7%). Our net undeveloped acreage in Colombia, not including acreage acquired through agreements still subject to government approval, is in the Mecaya Block (less than 1%); the Rio Magdalena Block (1%); the Azar Block (1.5%); the Turpial Block (1.8%); the Piedemonte Norte (2.5%); the Putumayo 1 Block (2%); the Catguas A Block (2.4%); the Piedemonte Sur Block (2.4%); the Rumiyaco block (2.6%); the Putumayo 10 Block (3.6%); the Catguas B Block (8.2%); the Cauca 6 Block (18.2%); the Magdalena Block (18.9%); and the Cauca 7 block (25.0%).

In Argentina, our net developed acreage includes acreage in the Puesto Morales Este Block (less than 1%); the Rinconada Norte Block (1.1%); the Palmar Largo Block (3.4%); the El Chivil Block (4%); the El Vinalar Block (4%); the Puesto Morales Block (4.1%); the Valle Morado Block (6%); and the Surubi Block (10.1%). Our net undeveloped acreage in Argentina is in the Rinconada Sur (3.7%); the Vaca Mahuida Block (8.3%); the Puesto Guevara Block (21.6%); and the Santa Victoria Block (33.7%).

In Peru, our net undeveloped acreage includes acreage in Block 129 (7.6%); Block 123 (15.2%); Block 107 (20.3%); Block 95 (24.9%); and Block 133 (31.9%).

In Brazil, our net developed acreage includes acreage in the Block REC-T 155 (21.4%). Our net undeveloped acreage, not including that acquired through agreements for which government approval is pending or which was relinquished after year-end, includes acreage in Block REC-T 129 (26.7%); Block REC-142 (25.3%); and Block REC-T 224 (26.6%).

Table of Contents

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 — 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

Ecopetrol S.A. (“Ecopetrol”), the Colombian majority state owned oil company, is the purchaser of virtually all of our Colombia crude oil production, and the source of the majority of our revenues. Sales to Ecopetrol accounted for 87%, 96% and 94% of our revenues in 2011, 2010 and 2009, respectively. We also sell a small portion of our Colombia crude oil production to Petrobras International Braspetro B.V. (“Petrobras”).

We have entered into agreements to sell to Ecopetrol all of the volume of crude oil production produced in the Chaza Block, Santana Block and Guayuyaco Block owned by our subsidiaries Gran Tierra Colombia Ltd. and Solana Petroleum Exploration (Colombia) Ltd. (the “Putumayo production”). The volume of crude oil does not include the volume of oil owned by the ANH corresponding to 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 are currently July 31, 2012. In the event that Ecopetrol does not accept a full delivery of this production, we may sell to Petrobras the crude oil not accepted.

We deliver our oil to Ecopetrol through our transportation facilities which include pipelines, gathering systems and trucking. 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, and (2) from Costayaco to Ecopetrol’s storage terminal at Neiva (Dina Station), approximately 350 kilometers north of the Chaza Block. 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 that port) with adjustments for specified fees depending on the port, including a port operation fee and a commercialization fee, and in the case where the point of sale is not at the Port of Tumaco, a transportation fee and transportation tax. Oil prices for sales to Petrobras International are based on WTI price less adjustments for quality, transportation, marketing and handling.

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 will 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. The agreements have expiration dates of July 29, 2012.

Our oil in Colombia is good quality light oil.

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. (“Refiner”). Our contract with Refiner expired on January 1, 2008; however, we are continuing sales of our oil under monthly agreements with Refiner. In the Noroeste basin, oil is delivered to the refinery by truck.

Shell C.A.P.S.A. (“Shell”) and YPF S.A. (“YPF”) are 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 Shell, Refiner and YPF accounted for 3%, 3% and 2%, respectively, of our oil and natural gas sales in 2011. Sales to Refiner accounted for 4% of our oil and natural gas sales in 2010 and 6% in 2009. 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 2011 and were nil in 2010 and 2009.

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 domestic sales. Our oil prices are agreed on a spot basis, based on WTI price less adjustments for quality, transportation and an adjustment equivalent to the export tax. We receive revenues in Argentine 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 well 1-ALV-02 BA in Block REC-T-155. Oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. Oil prices for sales to Petrobras are based on the monthly average Brent DTD price less $14.09 per barrel. The oil sales contract with Petrobras will expire on July 31, 2012, when long term testing at the 1-ALV-02 BA well is completed.

There were no sales in any countries other than Colombia, Argentina and Brazil in 2011, 2010 or 2009.

See “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 Item 1A “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 Item 1A “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 Item 8 “Financial Statements and Supplementary Data”, which information is incorporated by reference here. Long lived assets are Property, Plant and Equipment, which includes all oil and gas assets, furniture and fixtures, automobiles and computer equipment. No long lived assets are held in our country of domicile, which is the United States of America. ‘All Other’ assets include assets held by our corporate head office in Calgary, Alberta, Canada, and assets held in Brazil. Because all of our exploration and development operations are in South America, we face many risks attendant with these operations. See Item 1A "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, all the direct exploration costs which the Associate incurred. 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 2004, 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 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 near the end of the first quarter of 2005. This Exploration and Production Contract has significantly changed the way the industry views Colombia. In place of the earlier association contracts in which the contractor assumed all the exploration risk and Ecopetrol had the right to back-in afterwards, 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.

Table of Contents

Gran Tierra operates in Colombia through three branches – Gran Tierra Colombia, Solana Colombia and Petrolifera Colombia. All 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 Argentine 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 totalling $2.6 million under the Petroleum Plus program related to our production for the first, third and fourth quarters of 2010 and the fourth 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. Gran Tierra recognized revenue of $0.6 million during the year ended December 31, 2011 upon the sale of credits to a third party. We are negotiating with other parties for the sale of other credits.

In October 2010, the Argentine 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 Argentine 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.

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 Item 1A “Risk Factors” for a description of the risks associated with Argentine 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 generally 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.

Table of Contents

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 Item 1A "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 Petróleo Brasileiro S.A. ("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 by 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 Item 1A "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 2012, we plan to spend approximately $8.8 million in Colombia on capital programs related to environmental studies, community consultations, environmental remediation and scouting and basic engineering. In Peru, costs for environmental and social projects will be approximately $8.0 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 $0.2 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 2011, we experienced a limited number of environmental incidents and enacted the following environmental initiatives:

In Colombia:

- In the first quarter of 2011, the rollover of an oil transportation truck resulted in the release of 20 barrels of oil. Clean-up costs for this accident were substantially paid for by the transportation contractor since the rollover was due to an error by their driver. During the third and fourth quarters of 2011, heavy rain and flooding caused the release of 20 barrels of oil from the Santana water system station. Clean-up and remediation costs were $75,000. In each of these incidents Gran Tierra completed a full clean-up.

- A number of minor incidents on our blocks occurred during the year, each of which caused small quantities of oil to be spilled. In each incident Gran Tierra completed a full clean up and remediation of the affected area. Approximately 50 barrels of oil in total were lost as a result of these incidents.

In Argentina:

- An EIA was conducted for the Proa-2 drilling program.

- In the Surubi Oil field, metal fatigue on the 4” line at Proa-1 resulted in 30 barrels of oil being released. In the El Chivil field, 30 barrels of oil were spilled due to a defective pump valve. In each of these incidents Gran Tierra completed a full clean-up.

- A number of minor incidents on our blocks occurred during the year, each of which caused small quantities of oil to be spilled. In each incident Gran Tierra completed a full clean up and remediation of the affected area. Approximately 107 barrels of oil in total were lost as a result of these incidents.

In Peru, we started the Environmental Monitoring Program associated with drilling activity planned for Block 95. We also signed an agreement with the Pacaya Samiria Natural Reserve, in which we committed to implement systems to monitor environmental standards, support protection activities and support initiatives designed to provide for the reinvestment and distribution of earnings into the community. We also submitted an Environmental Management Plan for the relocation of four well pads in Block 107, completed the related consultation process for this activity and submitted the necessary environmental abandonment plans for Blocks 122 and 128.

In Brazil, we received EIA approvals for seismic on Block 224 and for drilling operations on Blocks 155,142 and 129, in the Recôncavo Basin.

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 Gran Tierra 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 Relations

In 2011, we continued standardized, quarterly reporting on our community relations 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 completed in 2011 are as follows:

Colombia

In 2011, our most significant community relations initiatives and investments were made in the Costayaco field. We also made voluntary investments in relation to community support during drilling projects in the year, during the Brillante 3D and Verdayaco 3D seismic projects and in the Santana, Guayuyaco, and Guepaje fields. Below is a description of Gran Tierra's $1.9 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 through various projects, including providing tuition, supplies, transportation and construction of facilities 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 the projects.

Various projects for the support of cultural identity such as sponsorship of local festivals that celebrate indigenous culture and history; construction of a workshop for local artisans and community centers; 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 urban and rural road bridge construction.

Table of Contents

Projects related to health, basic sanitation and housing including improving health facilities, providing supplies to health facilities, providing materials for house construction, constructing community kitchens and community centers.

Provided strong communications with the communities and undertake prior consultation process with ethnic minorities.

Argentina

In 2011, we invested approximately $0.5 million in the following activities:

Provided and distributed education materials to over 19 schools in our operated areas.

Provided training to teachers and students in sex 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.

Peru

In 2011, we invested approximately $0.7 million in the following activities:

Negotiated compensation arrangements with communities for use of their lands.

Provided consultation and education sessions with various communities located on our blocks.

Provided community training for environmental preservation.

Provided healthcare support services to communities in our blocks.

Provided community policing and monitoring services in communities in our blocks.

Provided temporary employment to residents in our blocks.

Brazil

In 2011, we invested approximately $150,000 on a compensation program with communities for use of their lands.
We started the evaluation and development of a Corporate Social Responsibility (“CSR”) project in the Pojuca Area. An assessment has been completed to identify social initiatives and communities’ needs, as well as stakeholder’s strengths, in municipalities around Block 155. The next step will be to evaluate initiatives for a CSR project implementation.

Employees

At December 31, 2011, we had 446 full-time employees - 39 located in the Calgary corporate office, 254 in Colombia (125 staff in Bogota and 129 field personnel), 90 in Argentina (47 office staff in Buenos Aires and 43 field personnel), 41 in Peru (both field and office staff) and 22 in Brazil (14 office staff in Rio de Janiero and Salvador and 8 field staff). 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 Securities Exchange Act of 1934 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.

Table of Contents

Item 1A. Risk Factors

Risks Related to Our Business

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.

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 could be disrupted by damage to this pipeline or displaced by Ecopetrol’s use of the pipeline itself. Starting in 2012, we will have a new transportation contract with Ecopetrol which will change 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 will take delivery at the end of the export pipeline. This will create 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 the reduced revenue risk. Ecopetrol will maintain responsibility for clean-up of any spilled oil and for pipeline repair.

Problems with these pipelines can cause interruptions to our producing activities if they are for a long enough duration that our storage facilities become full. For example, we experienced disruptions in transportation on this pipeline in March and April of 2008, again in each of June, July and August of 2009, again in June, August, and September 2010, and again in February 2011 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.

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

Over the years, our profile in Colombia has increased which creates a greater risk for us and our employees to be targeted by guerrilla or other criminal groups. Despite significant recent security gains, Colombia remains a country where safety is a significant concern. For over 40 years, the 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. In recent years, however, the government has successfully dissolved the AUC militia, a paramilitary group that originally sprouted up to combat the FARC and ELN. The dissolved AUC militia members have reorganized in the form of criminal gangs.

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 prone to guerrilla activity. In 1989, our predecessor company’s facilities in one field were attacked by guerrillas and operations were briefly disrupted. Again 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 targets, including the Ecopetrol - operated Trans Andean (OTA) export pipeline which transports oil from the Putumayo region. In March and April of 2008, again in each of June, July, August and October of 2009, again in June, August, and September 2010, and again in February 2011, sections of the Trans Andean pipeline were sabotaged by guerrillas, which temporarily reduced our deliveries to Ecopetrol during the affected periods.

Continuing attempts by the Colombian government to reduce or prevent guerrilla activity may not be successful and guerrilla activity may disrupt our operations in the future. There can also be no assurance that we can maintain the safety of our field and Bogota head office personnel or operations in Colombia or that this violence will not affect our operations in the future and cause significant loss.

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, Argentina, Peru and Calgary, 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.

27

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 Argentine 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 four 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 all of our production in Brazil is sold to Petrobras.

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 in the world. 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 2011, Argentina has experienced increased union activity and this may create disruptions in our Argentinian operations in the future. 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.

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 2012 calls for approximately $367 million to fund our exploration and development, which we intend to fund through existing cash and cash flows from operations. 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 private 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.

Table of Contents

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 million barrels. 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 million barrels.

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 million barrels. We have responded to the ANH in accordance with the provisions of the Chaza contract and are discussing the situation with them. However, 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.

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

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 United States dollars and foreign currencies. 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 production in Argentina is primarily invoiced in United States dollars, but payment is made in Argentine pesos, at the then current exchange rate. As a result, we are exposed to translation risk when local currency financial statements are translated to United States 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 Argentine peso and U.S. dollar has varied between 3.05 pesos to one U.S. dollar to 4.35 pesos to the U.S. dollar, a fluctuation of approximately 43%. Production in Brazil is invoiced and paid in Brazilian Real. Since September 1, 2005, the exchange rate of the Brazilian Real has varied between 1.56 Real to one U.S. dollar to 2.45 Real to the U.S. dollar, a variance of 57%. Foreign exchange gains were $nil in the year ended December 31, 2011. Realized foreign exchange losses were offset by $1.7 million of unrealized non-cash foreign exchange gains resulting from the translation of a deferred tax liability recorded on the purchase of Solana. The deferred tax liability is denominated in Colombian pesos and the devaluation of 1.5% in the Colombian Peso against the U.S. dollar in the year ended December 31, 2011 resulted in the foreign exchange gain.

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.

Exchange controls may prevent us from transferring funds abroad. For example, the Argentine 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 Argentine Central Bank. The Central Bank may require prior authorization and may or may not grant such authorization for our Argentine subsidiaries to make dividend payments to us and there may be a tax imposed with respect to the expatriation of the proceeds from our foreign subsidiaries. The Brazilian government has similar regulations in place regarding foreign exchange controls.

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.

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.

Table of Contents

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 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 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 one refiner, Refineria del Norte S.A, and the price is negotiated on a month by month basis. As a result of our acquisition of Petrolifera, we are now also selling our oil through short term contracts to Shell Compania Argentina de Petroleo S.A. and YPF S.A. and natural gas to Rafael G. Albenesi S.A. The Provincial governments have also been hurt by these changes as their effective royalty take has been reduced and capital investment in oilfields has declined, and so they are lobbying to change the situation. We are working with other oil and gas producers in the area, as well as Refineria del Norte S.A., to lobby the federal government for change. 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.

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 newly elected 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 point, we do hold significant land holdings in Peru and such actions by the newly 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 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 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.

Table of Contents

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/or 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. In particular, on March 18, 2011, we acquired Petrolifera (through a plan of arrangement), a company with substantial assets featuring both high working interest and operatorship in three of the four South American countries in which we operate. For the acquisition to be successful, we must be successful at retaining key employees, integrating Petrolifera’s operations and developing Petrolifera’s reserves. Such 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.

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 permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. 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.

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.

Table of Contents

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, 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 counties 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 Argentine proved reserves and a decrease in reserve volumes. In 2010, we recorded a ceiling test impairment loss of $23.6 million, including $17.9 million relating to the abandonment of the GTE.St.VMor-2001 sidetrack operations.

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.

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.

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.

Table of Contents

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 and $95 in 2011 demonstrating the inherent volatility in the market. Given the current economic environment and unstable conditions in the Middle East, Libya and the United States, 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 and 2011 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.

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 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;

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;

significant sales 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 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 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 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 our common stock.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

We have described our properties, reserves, acreage, wells, production and drilling activity in Part I, Item 1. “Business” of this Annual Report on Form 10-K, which information and descriptions are incorporated by reference here.

Table of Contents

Administrative Facilities

Our executive offices are located in Calgary Canada. Our primary executive offices comprise approximately 15,700 square feet, which we lease for approximately $33,000 per month under a lease that expires on October 30, 2015. We also lease additional space in Calgary that we use to supplement our primary executive office space. We lease administrative office space in Colombia, Argentina, Peru and Brazil. We believe that our current executive and administrative offices are sufficient for our purposes or, to the extent that we need additional office space, that additional office space will be readily available to us.

Item 3. Legal Proceedings

Gran Tierra is subject to a third party 10% net profits interest on 50% of Gran Tierra's production from the Costayaco field that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There is currently a disagreement between Gran Tierra and the third party as to the calculation of the net profits interest. Gran Tierra and the third party have agreed to resolve this issue through arbitration. An arbitration hearing was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. We expect to receive the arbitrator's decision in March 2012.

At this time no amount has been accrued in the financial statements as Gran Tierra does not consider it probable that a loss will be incurred. The disputed amount at December 31, 2011 is $9.6 million. If Gran Tierra is unsuccessful in arbitration this would also increase future net profit interests payable to this third party.

We have several other lawsuits and claims pending for which we currently cannot determine the ultimate result. We record costs as they are incurred or become determinable. We believe the resolution of these matters would not have a material adverse effect on our consolidated financial position or results of operations.

Item 4. Mine Safety Disclosures

Not applicable.

End of Item 4

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 20, 2012.

Name	Age	Position
Dana Coffield	53	President and Chief Executive Officer; Director
James Rozon	48	Acting Chief Financial Officer
Martin H. Eden	64	Chief Financial Officer
Shane O'Leary	55	Chief Operating Officer
David Hardy	57	General Counsel, Vice-President Legal, and Secretary
Rafael Orunesu	56	President and General Manager Gran Tierra Energy Argentina
Duncan Nightingale	53	President and General Manager Gran Tierra Energy Colombia
Julio Cesar Moreira	50	President and General Manager Gran Tierra Energy Bra

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 — AEC International — 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, SE 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 has participated in the discovery of over 130 million barrels of oil equivalent reserves.

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, acting Chief Financial Officer. On December 9, 2011, the Board of Directors of Gran Tierra appointed James Rozon the acting Chief Financial Officer and Principal Financial and Accounting Officer of Gran Tierra. Mr. Rozon has served as Gran Tierra's Corporate Controller from October 1, 2007 to present. 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 of America 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.

Martin H. Eden, Chief Financial Officer. Mr. Eden joined our company as Chief Financial Officer on January 2, 2007. He is currently on medical leave from Gran Tierra. He has extensive experience in accounting, finance and administration in the petroleum industry in Canada and overseas. During his career his responsibilities have included management of all finance related activities of Canadian oil and gas exploration and production companies operating in Canada, Africa and Central Asia. He was Chief Financial Officer of Artumas Group Inc., a publicly listed Canadian oil and gas company from April 2005 to December 2006 and was a director from June to October 2006. He has been president of Eden and Associates Ltd., a financial consulting firm, from January 1999 to present. From October 2004 to March 2005 he was the Chief Financial Officer of Chariot Energy Inc., a Canadian private oil and gas company. From January 2004 to September 2004, he was the Chief Financial Officer of Assure Energy Inc., a publicly traded oil and gas company listed in the United States. From January 2001 to December 2002, he was Chief Financial Officer of Geodyne Energy Inc., a publicly listed Canadian oil and gas company. From 1997 to 2000, he was Controller and subsequently Chief Financial Officer of Kyrgoil Corporation, a publicly listed Canadian oil and gas company with operations in Central Asia. He spent nine years with Nexen Inc. (1986-1996), including three years as Finance

Manager for Nexen's Yemen operations and six years in Nexen's financial reporting and special projects areas in its Canadian head office. Mr. Eden has worked in public practice, including two years as an audit manager for Coopers & Lybrand in East Africa. He is currently a director of Touchstone Oil and Gas Ltd., a private company. Mr. Eden holds a Bachelor of Science degree in Economics from Birmingham University, England, a Masters of Business Administration awarded by Brunel University, England, on behalf of Henley Management College and is a member of the Institute of Chartered Accountants of Alberta and the Institute of Chartered Accountants in England and Wales.

Table of Contents

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 3 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. He was most recently 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 million barrels 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 $180MM 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).

Table of Contents

PART II

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

Our common stock trades on the NYSE Amex, 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 21, 2012 there were approximately: 40 holders of record of shares of our common stock and 263,961,554 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately 8 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 8 holders of record of 8,512,707 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, 2010 through the end of the fourth quarter of 2011, the following table shows the high and low closing sale prices per share of our common stock as reported on the NYSE Amex.

	High	Low
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
Fourth Quarter 2010	$8.39	$7.23
Third Quarter 2010	$7.72	$5.06
Second Quarter 2010	$6.64	$4.70
First Quarter 2010	$6.08	$4.68

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 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

	12/06	12/07	12/08	12/09	12/10	12/11
Gran Tierra Energy Inc.	100.00	220.17	235.29	481.51	676.47	403.36
Russell Small Cap Completeness	100.00	104.85	63.98	88.10	111.56	107.19
Dow Jones US Exploration & Production TSM	100.00	140.30	82.74	117.09	138.63	132.95

The Dow Jones US Exploration and Production TSM was previously named the DJ Wilshire Exploration and Production.

Table of Contents

Item 6. Selected Financial Data

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

	Year Ended December 31, 2011	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007
Statement of Operations Data					
Revenues and other income					
Oil and natural gas sales	$ 596,191	$ 373,286	$ 262,629	$ 112,805	$ 31,853
Interest income	1,216	1,174	1,087	1,224	425
Total revenues and other income	597,407	374,460	263,716	114,029	32,278
Expenses					
Operating	86,497	59,446	40,784	19,218	10,474
DD&A expenses	231,235	163,573	135,863	25,737	9,415
G&A Expenses	60,389	40,241	28,787	18,593	10,232
Liquidated damages	-	-	-	-	7,367
Equity tax	8,271	-	-	-	-
Financial instruments (gain) loss	(1,522)	(44)	190	(193)	3,040
Gain on acquisition	(21,699)	-	-	-	-
Foreign exchange (gain) loss	(11)	16,838	19,797	6,235	(78)
Total expenses	363,160	280,054	225,421	69,590	40,450
Income (loss) before income taxes	234,247	94,406	38,295	44,439	(8,172)
Income tax expense	(107,330)	(57,234)	(24,354)	(20,944)	(295)
Net income (loss)	$ 126,917	$ 37,172	$ 13,941	$ 23,495	$ (8,467)
Net income (loss) per common share — basic	$ 0.46	$ 0.15	$ 0.06	$ 0.19	$ (0.09)
Net income (loss) per common share — diluted	$ 0.45	$ 0.14	$ 0.05	$ 0.16	$ (0.09)

Balance Sheet Data	As at December 31, 2011	As at December 31, 2010	As at December 31, 2009	As at December 31, 2008	As at December 31, 2007
Cash and cash equivalents	$ 351,685	$ 355,428	$ 270,786	$ 176,754	$ 18,189
Working capital (including cash)	213,100	265,835	215,161	132,807	8,058
Oil and gas properties	1,036,850	721,157	709,568	765,050	63,202
Deferred tax asset - long term	4,747	-	7,218	10,131	1,839
Total assets	1,626,780	1,249,254	1,143,808	1,072,625	112,797
Deferred tax liability - long term	186,799	204,570	216,625	213,093	9,235
Total long-term liabilities	207,633	210,075	221,786	218,461	12,553
Shareholders’ equity	$ 1,174,318	$ 886,866	$ 816,426	$ 791,926	$ 76,792

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 Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further details.

Table of Contents

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations

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

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

Overview

We are an independent international energy company incorporated in the 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. Our reportable segments are Colombia, Argentina and Peru. Brazil is not a reportable segment because the level of activity in Brazil is not significant at this time. For the year ended December 31, 2011, Colombia generated 91% (2010 - 96%; 2009 - 95%) of our revenue and other income.

As of December 31, 2011, we had estimated proved reserves NAR of 34.0 MMBOE, comprising 91% oil and 9% natural gas, of which 76% were proved developed reserves. Our primary source of liquidity is cash generated from our operations.

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.

On June 15, 2011, we completed the acquisition of a 70% participating interest in four blocks in Brazil. The agreement had an effective date of September 1, 2010. Purchase consideration totalled $40.1 million. With the exception of one block which has a producing well, the remaining blocks are unproved properties.

In September 2011, we announced two farm-in agreements with Statoil do Brasil Ltda. ("Statoil") in a joint venture with PetróleoBrasileiro S.A. ("Petrobras"), in Brazil’s deepwater offshore Camamu-Almada Basin, subject to obtaining regulatory approval from Agência Nacional de Petróleo, Gás Natural e Biocombustíveis ("ANP"). ANP approval for the Block BM-CAL-7 farmout agreement was received in first quarter of 2012. The ANP has announced the 1-STAT-7-BAS exploration well has been completed after reaching a total measured depth of 3,651 meters. Contractually, Gran Tierra is restricted from discussing well results. In accordance with the terms of the farmout agreement,we gave notice to Statoil that we will 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 farmout agreement for BM-CAL-10 has been terminated and we will not receive any interest in BM-CAL-10.

Inflation has not had a material impact on our results of operations in the three years ended December 31, 2011 and is not expected to have a material impact on our results of operations in the future.

The price of oil is a critical factor to our business and the price of oil has historically been volatile. Volatility could be detrimental to our financial performance. During 2011, the average price realized for our oil was $96.60 per barrel (2010 - $71.19; 2009 – $56.79).

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,				
	2011	% Change	2010	% Change	2009
Estimated Proved Oil and Gas Reserves, NAR, at December 31 (MMBOE)(1)	34.0	43	23.8	6	22.4
Production (BOEPD) (1)(2)	17,408	20	14,448	14	12,684
Prices Realized - per BOE	$93.83	33	$70.79	25	$56.73
Revenue and Other Income ($000s)	$597,407	60	$374,460	42	$263,716
Net Income ($000s)	$126,917	241	$37,172	167	$13,941
Net Income Per Share – Basic	$0.46	207	$0.15	150	$0.06
Net Income Per Share – Diluted	$0.45	221	$0.14	180	$0.05
Funds Flow From Operations ($000s) (3)	$319,046	57	$203,136	27	$159,479
Capital Expenditures ($000s)	$327,647	85	$177,039	101	$88,124

Table of Contents

	As at December 31,				
	2011	% Change	2010	% Change	2009
Cash & Cash Equivalents ($000s)	$ 351,685	(1)	$ 355,428	31	$ 270,786
Working Capital (including cash & cash equivalents) ($000s)	$ 213,100	(20)	$ 265,835	24	$ 215,161
Property, Plant and Equipment ($000s)	$ 1,044,842	44	$ 727,024	2	$ 712,743

(1) Gas volumes are converted to BOE at the rate of six Mcf of gas per barrel of oil, based on the approximate relative energy content of gas and oil. The conversion ratio does not assume price equivalency and the price for a barrel of oil equivalent for natural gas may differ significantly from the price of a barrel of oil.

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

(3) 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"), deferred taxes, stock-based compensation, (gain) loss on financial instruments, unrealized foreign exchange (gain) loss, settlement of asset retirement obligation, equity tax and gain on acquisition. A reconciliation from funds flow from operations to net income is as follows:

	Year Ended December 31,		
Funds Flow From Operations - Non-GAAP Measure ($000s)	2011	2010	2009
Net income	$126,917	$37,172	$13,941
Adjustments to reconcile net income to funds flow from operations			
DD&A expenses	231,235	163,573	135,863
Deferred taxes	(29,222)	(20,090)	(15,355)
Stock-based compensation	12,767	8,025	5,309
(Gain) loss on financial instruments	(1,354)	(44)	277
Unrealized foreign exchange (gain) loss	(1,695)	14,786	19,496
Settlement of asset retirement obligation	(345)	(286)	(52)
Equity tax	2,442	-	-
Gain on acquisition	(21,699)	-	-
Funds flows from operations	$319,046	$203,136	$159,479

Table of Contents

Operational Highlights for the Year Ended December 31, 2011

- In 2011, oil and natural gas production, NAR and inventory adjustments, averaged 17,408 BOEPD, an increase of 20% over 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. Production NAR from Petrolifera's properties during 2011 was 1,811 BOEPD.

- 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 primarily to positive technical revisions to Costayaco reserves (based on reservoir performance), the drilling of additional appraisal wells in the Moqueta field, the inclusion of proved reserves associated with the Petrolifera acquisition and the 70% working interest in Block 155 acquired in Brazil, which more than offset 2011 oil production. 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 as at December 31, 2010. The increase was due to the acquisition of Petrolifera. At December 31, 2011, 75% of proved gas reserves were in the Sierra Nevada Block and 19% were in the Puesto Morales Blocks, both of which were acquired in the Petrolifera acquisition. Estimated probable and possible gas reserves, NAR, as of December 31, 2011 were 25.7 Bcf and 116.5 Bcf, respectively.

Colombia

- In the Moqueta field in the Chaza Block, the Moqueta -4 delineation well was successfully completed and confirmed additional oil bearing reservoirs. We completed two additional development wells in the Moqueta field: Moqueta -5 and Moqueta -6. Construction of the Moqueta-to-Costayaco pipeline was completed with transportation of first oil production from Moqueta commencing in June of 2011. A parallel four-inch gas line was completed that will be used to transport gas from Costayaco to Moqueta for anticipated gas injection for pressure support.

- In the Costayaco field, we completed three development wells.

- In the Guayuyaco and Garibay Blocks, the Juanambu -3 and Jilguero -2 development wells were completed as producing wells and the Melero -1 exploration well was completed and resulted in an oil discovery.

- We entered into a farmout agreement with CEPSA Colombia S.A. ("CEPSAC"), a wholly-owned subsidiary of Compañia Española de Petróleos S.A. We will earn a 45% non-operated working interest in the Llanos-22 Block (CEPSAC will retain 55% and operatorship) and CEPSAC will farm-in for a 30% working interest on the Piedemonte Norte Block. Under the terms of the farm-in agreements, in addition to the swap of the 30% working interest in Piedemonte Norte block, we will pay $1.5 million towards historical costs and a partial carry on the current well being drilled. The completion of the transfer is subject to approval by Colombia's Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH"). Our partner began drilling the Ramiriqui-1 oil exploration well in the fourth quarter of 2011.

- We drilled exploration wells on the Chaza Block, the Magdalena Block, the Piedemonte Sur Block and the Rumiyaco Block all of which were plugged and abandoned.

Argentina

- We completed drilling the first of four new development wells in the Puesto Morales Block, with the purpose of improving recovery and growing production from this mature oil field. We completed workovers on 18 wells, with successful results. We also drilled and completed two producing development wells on the Puesto Morales Este Block.

- Our partner drilled four exploration wells in the Rinconada Norte Block which resulted in new discoveries of oil, one of which tested 1,023 BOE gross per day. A wholly-owned subsidiary of America Petrogas Inc. is the operator of the Rinconada Norte Block with a 65% working interest, while we hold a 35% non-operated working interest.

- We successfully farmed out a 50% interest in the Santa Victoria Block in the Noroeste Basin of northwestern Argentina to Apache Corporation ("Apache") in March 2011.

Peru

- In January 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block to us. A drilling location has been identified for the first exploration well on Block 95, with civil construction initiated in the third quarter of 2011.

- In September 2010, we acquired a 20% non-operated working interest in ConocoPhillips operated Block 123, Block 124 and Block 129, subject to government approval. The approval for these blocks was granted in March 2011 with final assignment completed in April 2011. We subsequently relinquished our interest in Block 124.

- We drilled the Kanatari -1 exploration well on Block 128 which was plugged and abandoned and subsequently relinquished our interest in Blocks 122 and 128.

Brazil

- On June 15, 2011, we received final approvals for the acquisition of a 70% participating interest in Blocks 129, 142, 155 and 224 in the onshore Recôncavo Basin of Brazil and also became the operator of these fields effective from that date.

- We drilled two gross exploration wells on Block 142 and Block 129 and spud a delineation well on Block 155.

- We announced two farm-in agreements with Statoil in a joint venture with Petrobras, in Brazil's deepwater offshore Camamu-Almada Basin. The ANP has announced the 1-STAT-7-BAS exploration well has been completed after reaching a total measured depth of 3,651 meters. Contractually, we are restricted from discussing well results. In accordance with the terms of the farmout agreement, we gave notice to Statoil that we will not enter into and assume our share of the work obligations of the second exploration period on one of the two blocks and as a result the farmout agreement for this block was terminated. ANP approval was received for the second block in the first quarter of 2012.

Table of Contents

Financial Highlights for the Year Ended December 31, 2011

Revenue and other income increased by 60% to $597.4 million in 2011 compared with $374.5 million in 2010 due to increased production and higher oil prices. Average prices realized per BOE in 2011 were $93.83, an increase of 33% compared with $70.79 in 2010.

Net income grew by 241% from the prior year to $126.9 million, representing basic net income per share of $0.46 and diluted net income per share of $0.45. This compares with net income of $37.2 million, or $0.15 per share basic and $0.14 per share diluted, in 2010. The increase in net income was the result of increased oil and natural gas sales, a $21.7 million gain on the Petrolifera acquisition and the absence of foreign exchange losses, 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 general and administrative ("G&A") expenses. The equity tax is assessed every four years.

Funds flow from operations increased 57% to $319.0 million in 2011 from $203.1 million in 2010. The increase was primarily due to increased oil and natural gas sales and improved oil prices as compared with the prior year, partially offset by a Colombian equity tax and increased operating and G&A expenses in 2011.

Cash and cash equivalents was $351.7 million at December 31, 2011 compared with $355.4 million at December 31, 2010. The change in cash and cash equivalents during 2011 was primarily the result of $333.2 million of capital expenditures offset by funds flow from operations of $319.0 million and a decrease in non-cash working capital of $37.8 million during 2011.

Working capital (including cash and cash equivalents) was $213.1 million at December 31, 2011, which is a $52.7 million decrease from December 31, 2010, due mainly to a $51.7 million increase in taxes payable due to increased taxable income in Colombia and a $40.9 million increase in accounts payable and accrued liabilities, partially offset by a $26.3 million increase in accounts receivable due to increased sales and a $14.5 million increase in taxes receivable. The increase in accounts payable and accrued liabilities is a result of operations acquired in the Petrolifera acquisition, the commencement of operations in Brazil and increased royalty payables as a result of increased production and higher realized prices. The increase in taxes receivable primarily relates to an increase in VAT receivable as a result of increased capital expenditures.

Property, plant and equipment at December 31, 2011 was $1.0 billion, an increase of $317.8 million from December 31, 2010, as a result of the $327.6 million 2011 work program capital expenditures, $219.7 million of additions from the Petrolifera acquisition and $1.7 million of asset retirement obligations; partially offset by $231.2 million of DD&A expenses.

Business Combination

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. For further details reference should be made to Note 3 of the consolidated financial statements.

The acquisition was accounted for using the acquisition method, with Gran Tierra being the acquirer, whereby Petrolifera's assets acquired and liabilities assumed were recorded at their fair values as at the acquisition date and the results of Petrolifera were 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:		
Common shares 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 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. The gain reflects 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.

Table of Contents

Production from the Petrolifera properties from the acquisition date to December 31, 2011 amounted to 1,811 BOEPD NAR with oil and natural gas sales of $32.5 million. For the post acquisition period, Petrolifera recorded an after tax loss of $8.0 million.

Business Environment Outlook

Our revenues have been significantly impacted by 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. However, based on projected production, prices, costs and our current liquidity position, we believe that our current operations and 2012 capital expenditure program can be maintained from cash flow from existing operations and cash on hand, barring unforeseen events or a severe downturn in oil and gas prices. Should our operating cash flow decline, we would examine measures such as reducing our capital expenditure program, issuance of debt, disposition of assets, or issuance of equity. The continuing uncertainty regarding the Middle East and Libya and continued economic instability in the United States and Europe is 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 our common stock. If the price of our common stock declines, our ability to utilize our stock to raise capital may be negatively affected. Also, raising funds by issuing stock or other equity securities would further dilute our existing shareholders, and this dilution would be exacerbated by a decline in our stock 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 and will expose us to interest rate risk. Depending on the currency used to borrow money, we may also be exposed to further foreign exchange risk. Our ability to borrow money and the interest rate we pay for any money we borrow will be affected by market conditions, and we cannot predict what price we may pay for any borrowed money.

Consolidated Results of Operations

Consolidated Results of Operations (Thousands of U.S. Dollars)	Year Ended December 31, 2011	% Change	2010	% Change	2009
Oil and natural gas sales	$ 596,191	60	$ 373,286	42	$ 262,629
Interest income	1,216	4	1,174	8	1,087
	597,407	60	374,460	42	263,716
Operating expenses	86,497	46	59,446	46	40,784
DD&A expenses	231,235	41	163,573	20	135,863
G&A expenses	60,389	50	40,241	40	28,787
Equity tax	8,271	-	-	-	-
Financial instruments (gain) loss	(1,522)	-	(44)	(123)	190
Gain on acquisition	(21,699)	-	-	-	-
Foreign exchange (gain) loss	(11)	-	16,838	(15)	19,797
	363,160	30	280,054	24	225,421
Income before income taxes	234,247	148	94,406	147	38,295
Income tax expense	(107,330)	88	(57,234)	135	(24,354)

Net income	$	126,917	241	$	37,172	167	$	13,941
Production								
Oil and NGL's, bbl		6,118,705	17		5,228,554	13		4,621,546
Natural gas, Mcf		1,411,188	425		268,776	448		49,028
Total production, BOE (1)		6,353,903	20		5,273,350	14		4,629,717
Average Prices								
Oil and NGL's per bbl	$	96.60	36	$	71.19	25	$	56.79
Natural gas per Mcf	$	3.65	(6)	$	3.90	(1)	$	3.93
Consolidated Results of Operations ("per BOE")								
Oil and natural gas sales	$	93.83	33	$	70.79	25	$	56.73
Interest income		0.19	(14)		0.22	(4)		0.23
		94.02	32		71.01	25		56.96
Operating expenses		13.61	21		11.27	28		8.81
DD&A expenses		36.39	17		31.02	6		29.35
G&A expenses		9.50	25		7.63	23		6.22
Equity tax		1.30	-		-	-		-
Financial instruments (gain) loss		(0.24)	-		(0.01)	(125)		0.04
Gain on acquisition		(3.42)	-		-	-		-
Foreign exchange (gain) loss		-	-		3.19	(25)		4.28
		57.14	8		53.10	9		48.70
Income before income taxes		36.88	106		17.91	117		8.26
Income tax expenses		(16.89)	56		(10.85)	106		(5.26)
Net income	$	19.99	183	$	7.06	135	$	3.00

(1) Production represents production volumes NAR adjusted for inventory changes. NGL volumes are converted to BOE on a one-to-one basis with oil. Gas volumes are converted to BOE at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

Table of Contents

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, 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 West Texas Intermediate ("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 Argentine 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.

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.

Table of Contents

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 $1.7 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 $14.8 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.

Our capital expenditures during 2011 were $327.6 million (after changes in non-cash working capital and net of proceeds from disposition of oil and gas properties) representing a significant increase from capital expenditures in 2010 of $177.0 million. In 2011, we made capital expenditures included drilling and acquisition expenditures of $225.4 million, facilities expenses of $38.0 million, geological and geophysical expenses of $47.8 million and other expenditures of $16.4 million. Additionally, we had $219.7 million of additions to property, plant and equipment from the Petrolifera acquisition.

Consolidated Results of Operations for the Year Ended December 31, 2010 Compared with the Results for the Year Ended December 31, 2009

Net income of $37.2 million, or $0.15 per share basic and $0.14 per share diluted, was recorded in 2010 compared with $13.9 million, or $0.06 per share basic and $0.05 per share diluted, in 2009. A 42% increase in revenue and other income to $374.5 million from $263.7 million recorded in 2009 was partially offset by an $18.7 million increase in operating expenses, a $11.5 million increase in G&A expenses, a $27.7 million increase in DD&A, and a $32.9 million increase in income tax expense.

Revenue and other income increased 42% as a result of a 13% increase in oil production combined with a 25% improvement in oil prices.

Oil and NGL production, NAR, in 2010 increased to 5.2 MMbbl compared with 4.6 MMbbl in 2009, due to increased production from our Colombia operations. Average realized oil prices for 2010 increased to $71.19 per barrel from $56.79 per barrel in 2009, reflecting higher WTI oil prices.

The additional government royalty for the Costayaco Field (described in "Segmented Operations - Colombia") began in the fourth quarter of 2009 and was paid for only three months of 2009 versus the full year of 2010. As a result, our share of production was reduced by a total of 947,000 BOE's relating to this additional royalty in 2010 as compared with only 328,000 BOE in 2009. Since our production volumes are reported NAR and this royalty structure was not in place for an equal amount of time in 2009 and 2010, certain changes between these years, including volumes, changes in per BOE operating costs, and per BOE general and administrative costs, are not readily comparable. For instance, the increase in the Costayaco field production does not appear as high in comparison with 2009 as it would appear without the additional royalty volumes deducted. Similarly, the per BOE operating and G&A expenses appear higher on a per BOE basis in 2010 than in 2009 as the costs are divided over a smaller base after royalties are deducted.

Operating expenses for 2010 amounted to $59.4 million, a 46% increase from the prior year total of $40.8 million. The increase in operating expenses occurred primarily in Colombia and was due to an enhanced workover program related to the Costayaco area, an increase in transportation costs related to increased production and pipeline maintenance, and an increase in producing wells in Costayaco. Operating expenses on a BOE basis in 2010 were $11.27, a 28% increase from 2009 reflecting both the increase in total operating costs and the effect of the additional government royalty payable on per BOE calculations, partially offset by an increase in production.

DD&A expenses for 2010 increased to $163.6 million compared with $135.9 million in 2009. The increase in production levels was partially offset by an increase of reserves at year-end and a reduction of future development costs included in the depletable base as compared with 2009. DD&A expenses in 2010 included a $23.6 million ceiling test impairment for our Argentina cost center, of which $17.9 million related to the abandonment of the GTE.St.VMor-2001 sidetrack operations, as compared with a $1.9 million charge in 2009. On a BOE basis, DD&A in 2010 was $31.02 compared with $29.35 for 2009, representing a 6% increase resulting from the ceiling test impairment loss offset partially by increased reserves and decreased future development costs.

G&A expenses of $40.2 million for 2010 were 40% higher than 2009 due to increased employee related costs reflecting the expansion of operations in Peru, Brazil, and Colombia and higher business development costs. G&A expenses per BOE increased 23% to $7.63 per BOE compared with $6.22 per BOE for 2009. The increase in G&A expenses on a per BOE basis over the prior year was compounded by the additional royalty paid in 2010.

The foreign exchange loss of $16.8 million for 2010, of which $14.8 million is an unrealized non-cash foreign exchange loss, compares to $19.8 million recorded in 2009, of which $19.5 million is an unrealized non-cash foreign exchange loss. These losses originate in Colombia and relate to foreign exchange losses resulting from the translation of a deferred tax liability.

Income tax expense for 2010 amounted to $57.2 million compared with $24.4 million recorded in 2009. This represents an increase of 135% in annual income tax expense, primarily as a result of higher profits and the application of a valuation allowance against previously recognized deferred tax assets associated with Argentina. The decrease in the 2010 effective tax rate to 61% from 64% in 2009 is primarily due to a decrease in the valuation allowance associated with losses in our U.S., Canadian, Peru and Brazil business units, partially offset by the increase in the valuation allowance associated with losses in our Argentina business units. The variance from the 35% U.S. statutory rate for 2010 results from foreign currency translation losses that are neither taxable nor deductible for tax purposes in each of the respective jurisdictions, the valuation allowances as described above, enhanced tax depreciation incentive in Colombia, and Colombia third party royalty payments that are not deductible for tax purposes. Similar factors cause the variance from the 35% U.S. statutory rate for 2009.

Estimated Oil and Gas Reserves

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 a 70% working interest in Block 155 in Brazil, which more than offset 2011 oil production. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2011 were 10.5 MMbbl and 17.6 MMbbl, respectively.

Table of Contents

Estimated proved gas reserves, NAR, as of December 31, 2011, were 18.3 Bcf compared with 1.2 Bcf at December 31, 2010. The increase was due to the acquisition of Petrolifera. At December 31, 2011, 75% of proved gas reserves were in the Sierra Nevada Block and 19% were in the Puesto Morales Blocks, both of which were acquired in the Petrolifera acquisition. Estimated probable and possible gas reserves, NAR, as of December 31, 2011 were 25.7 Bcf and 116.5 Bcf, respectively.

Estimated proved oil and NGL reserves, NAR, as of December 31, 2010, were 23.6 MMbbl, a 7 % increase from the estimated proved reserves as at December 31, 2009. The increase was generated by our Colombian operations and resulted from our exploration success in Moqueta and from sustained reservoir performance in Costayaco, which led to conversion of probable reserves to proved reserves and which more than offset 2010 production of oil. Estimated probable and possible oil and NGL reserves, NAR, as of December 31, 2010 were 7.4 MMbbl and 16.3 MMbbl, respectively.

Estimated proved gas reserves, NAR, as of December 31, 2010, were 1.2 Bcf, a 37 % decrease from the estimated proved reserves as at December 31, 2009. Estimated probable and possible gas reserves, NAR, as of December 31, 2010 were 0.1 Bcf and 42.1 Bcf, respectively.

2012 Work Program and Capital Expenditure Program

In December 2011, we announced the details of our 2012 capital program. We have planned a 2012 capital budget of $367 million, including $182 million for Colombia, $68 million for Brazil, $53 million for Argentina, $62 million for Peru and $2 million associated with corporate activities. Of this, $246 million is for drilling, $39 million is for facilities, equipment and pipelines and $82 million is for geological and geophysical (“G&G”) expenditures. Of the $246 million allocated to drilling, approximately $152 million is for exploration, and the balance is for delineation and development drilling.

We expect that our committed and discretionary 2012 capital program will be funded from cash flow from operations and cash on hand.

Our 2012 work program is intended to create both growth and value through strategic acquisitions of working interests, by leveraging existing assets to increase reserves and production levels and through the construction of pipelines and facilities in the areas with proved reserves. We are financing our capital program through cash flows from operations and cash on hand, while retaining financial flexibility with a strong cash position and no debt, so that we can be positioned to undertake further development opportunities and to pursue value-add 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 will be expended as set forth in our 2012 work program, there may be circumstances where, for sound business reasons, actual expenditures may in fact differ.

Excluding potential exploration success, production in 2012 is expected to range between 20,000 and 21,000 BOEPD NAR.

Segmented Results – Colombia

	Year Ended December 31,				
Segmented Results of Operations – Colombia	2011	% Change	2010	% Change	2009
(Thousands of U.S. Dollars)					
Oil and natural gas sales	$543,999	51	$359,302	44	$248,834
Interest income	492	7	460	(1)	466

	544,491	51	359,762	44	249,300
Operating expenses	58,081	15	50,431	52	33,091
DD&A expenses	141,133	6	133,728	5	127,213
G&A expenses	25,116	65	15,216	17	13,011
Equity tax	8,271	-	-	-	-
Foreign exchange (gain) loss	(1,626)	(109)	17,901	(11)	20,158
	230,975	6	217,276	12	193,473
Income before income taxes	$313,516	120	$142,486	155	$55,827
Production					
Oil and NGL's, bbl	5,348,885	8	4,944,510	15	4,284,230
Natural gas, Mcf	267,612	-	268,776	448	49,028
Total production, BOE (1)	5,393,487	8	4,989,306	16	4,292,401
Average Prices					
Oil and NGL's per bbl	$101.42	40	$72.45	25	$58.04
Natural gas per Mcf	$5.72	47	$3.90	(1)	$3.93
Segmented Results of Operations per BOE					
Oil and natural gas sales	$100.86	40	$72.01	24	$57.97
Interest income	0.09	-	0.09	(18)	0.11
	100.95	40	72.10	24	58.08
Operating expenses	10.77	7	10.11	31	7.71
DD&A expenses	26.17	(2)	26.80	(10)	29.64
G&A expenses	4.66	53	3.05	1	3.03
Equity tax	1.53	-	-	-	-
Foreign exchange (gain) loss	(0.30)	(108)	3.59	(24)	4.70
	42.83	(2)	43.55	(3)	45.08
Income before income taxes	$58.12	104	$28.55	120	$13.00

(1) Production represents production volumes NAR adjusted for inventory changes. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per barrel of oil, based upon the approximate relative energy content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices

Table of Contents

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 is 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 well Juanambu -3 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).

As a result of achieving gross field production of five MMbbl in our Costayaco field in the fourth quarter of 2009, 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 2011. 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 barrels of oil per day and $100 WTI price per barrel are approximately 27.9%, including the additional government royalty of approximately 20.5%. The ANH sliding scale royalty at 17,000 barrels of oil per day is approximately 9.2% and this royalty is deductible prior to calculating the additional government royalty.

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 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. Increased costs in our depletable pools were offset by higher reserves.

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. The Colombian Peso devalued by 1.5% against the U.S. dollar in the year ended December 31, 2011 resulting in the unrealized foreign exchange gain. In 2010, the Colombian Peso strengthened against the U.S. dollar by 6%. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $94,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

Table of Contents

Segmented Results of Operations – Colombia for the Year Ended December 31, 2010 Compared with the Results for the Year Ended December 31, 2009

For the year ended December 31, 2010, income before income taxes from Colombia amounted to $142.5 million compared with income before taxes of $55.8 million recorded in 2009. An increase in production revenue more than offset increased operating, G&A, and DD&A expenses.

For the year ended December 31, 2010, production of oil and NGLs, NAR, increased by 15% to 4.9 MMbbl compared with 4.3 MMbbl in 2009. The increase in production is primarily due to the increase in wells on stream in Costayaco and the success of the Costayaco workover program. Production levels are after government royalties ranging from 8% to 26% and third party royalties of 2% to 10%. The additional government royalty paid in 2010 (discussed above) reduced the increase in total production from the Costayaco field as compared with the prior year.

Our Colombian operating results for the year ended December 31, 2010 were principally driven by the increase in production volumes and the associated increase in workover, transportation, operating, G&A and DD&A expenses. In 2010, Colombia production included Costayaco -1, -2, -3, -4, -8, -9, -10 (January 2010), and -11 (June 2010), Juanambu -1 and -2, and the Santana Block. In 2009, Colombia production included Costayaco –1,-2,-3,-4,-5, -8 (July 2009), -9 (September 2009), and Juanambu -1.

Outages on the OTA pipeline result when sections of the pipeline are damaged. Outages reduced our deliveries to Ecopetrol for 29 days in 2010 (7 days in June and 22 days in September), as compared with 46 days in 2009 (32 days in July and August and 14 days in June). In January 2009, the Juanambu and Costayaco fields were also shut in for 10 days due to a general strike in the region where our operations are located. The overall decrease in sales as a result of the disruptions is estimated to be approximately 2% of total sales in 2010 and 14% of total sales in 2009.

Revenue and interest were positively affected by an increase in net realized oil prices in 2010 compared with 2009. The average net realized prices for oil, which are based on WTI prices, increased by 25% to $72.45 per barrel for the year ended December 31, 2010 compared with 2009. Increased production combined with the increased net realized oil price resulted in our revenue and interest from Colombia for the year ended December 31, 2010 increasing by 44% to $359.8 million from 2009 levels.

As a result of achieving gross field production of five million barrels in our Costayaco field during the month of September 2009, we became subject to an additional government royalty payable. The additional royalty is calculated on 30% of the field production revenue over an inflation adjusted trigger point. That trigger point was $32.13 for 2010 and $30.22 for 2009. Production revenue for this calculation is based on production volumes net of other government royalty volumes. In 2010, the actual government royalties at Costayaco averaged 24% including the additional government royalty of 15%. In 2009, the government royalties for the year averaged 16%, including the additional government royalty, once it became effective September 2009.

Operating expenses for the year ended December 31, 2010 increased to $50.4 million from $33.1 million in 2009. The increased operating expenses resulted from the Costayaco workover program ($6.6 million higher than in 2009), increased trucking resulting from increased volumes and OTA pipeline maintenance, and an increase in producing wells in Costayaco for 2010. On a per BOE basis, operating expenses for 2010 increased to $10.11 compared with $7.71 incurred in 2009, reflecting higher operating costs partially offset by the effect of the increase in total production. The additional government royalty paid in 2010 as compared with 2009 further increased the per BOE operating cost amounts from 2009.

For 2010, DD&A expenses increased to $133.7 million from $127.2 million in 2009. Increased production levels partially offset by higher oil reserve levels and lower future development costs added to the depletable base, accounted for the increase in DD&A expenses. On a per BOE basis, DD&A expenses in Colombia decreased by 10% to $26.80 for 2010, compared with $29.64 for 2009, due to higher production offset by increased proved reserves and lower future development costs.

Higher G&A expenses incurred to manage the increased level of development and operating activities resulted in G&A expense increasing to $15.2 million for the year ended December 31, 2010 from $13.0 million incurred in 2009. On a per BOE basis, G&A expenses in 2010 increased by 1% to $3.05 from $3.03 in 2009, due to higher costs partially offset by higher production. The additional government royalty paid in 2010 as compared with 2009 further increased the per BOE G&A amounts from 2009.

The foreign exchange loss of $17.9 million for the year ended December 31, 2010 includes an unrealized non-cash foreign exchange loss of $14.6 million and compares to a foreign exchange loss of $20.2 million in 2009, including an unrealized non-cash foreign exchange loss of $19.3 million. The unrealized non-cash foreign exchange loss resulted primarily from the translation of a deferred tax liability recognized on the purchase of Solana Resources Limited ("Solana"). This deferred tax liability, a monetary liability, is denominated in the local currency of the Colombian foreign operations and as a result, foreign exchange gains and losses have been calculated on conversion to the U.S. dollar functional currency.

Capital Program - Colombia

The Petrolifera acquisition added interests in three blocks in Colombia: the Sierra Nevada Block and the Magdalena Block in the Lower Magdalena Basin and the Turpial Block in the Middle Magdalena Basin.

Capital expenditures in Colombia during 2011 were $202.6 million, an increase of 92% from 2010. The following table provides a breakdown of capital expenditures during 2011, 2010 and 2009:

Segmented Capital Program – Colombia	Year Ended December 31,		
(Millions of U.S. Dollars)	2011	2010	2009
Drilling and completion	$105.3	$60.2	$46.0
Facilities and equipment	33.0	25.2	14.7
Geological and geophysical	30.0	22.0	15.1
Other	34.3	(1.9)	5.6
	$202.6	$105.5	$81.4

49

Table of Contents

The significant elements of our 2011 Capital Program in Colombia were as follows:

- Costayaco Field, Chaza Block (100% working interest and Operator)

We completed three development wells in the Costayaco field. The Costayaco -12 and -13 development wells were drilled as infill production wells to test the respective northern and southern extensions of the Costayaco field. Production from these wells is intended to assist in maintaining the production plateau at the Costayaco field; these wells will be converted to water-injectors to assist with pressure maintenance in the field later in the Costayaco field life. The Costayaco-14 development well was completed as a water injector well for pressure support in the Costayaco field.

We completed upgrades to the pumping station, battery and support facilities and a project to electrify the field was completed in December 2011.

- Moqueta Field, Chaza Block (100% working interest and Operator)

We completed three development wells in the Moqueta field, Moqueta -4, -5 and -6. All three wells are currently on production. The Moqueta -4 development well was successfully completed and tested 1,674 BOPD confirming additional oil bearing reservoirs. The Moqueta -5 development well resulted in production rates of 730 barrels of oil per day. The Moqueta -6 development well was drilled and tested 144 BOPD natural flow.

Construction of facilities at the Moqueta field commenced in 2011. In 2011, the 6-inch diameter, 8 km pipeline connecting the Moqueta and Costayaco infrastructure was completed. We also completed a parallel 4-inch gas line that will be used to transport gas or water from Costayaco to Moqueta for anticipated gas injection for pressure support.

We commenced the acquisition of 3D seismic to assist in refining the mapping of the Moqueta field and planning further delineation and development drilling.

- Guayuyaco Block (70% working interest and Operator)

The Juanambu -3 development well was completed as a producing well. We acquired 77 square kilometers of 3D seismic and acquired pumping equipment.

- Garibay Block (50% non-operated working interest)

The Melero -1 exploration well was drilled and completed and resulted in an oil discovery. The Jilguero -2 development well was also completed as a producing well. Both of these wells will begin long-term testing in the first quarter of 2012. We also completed civil works and upgraded facilities.

- Other Prospects

During 2011, we completed the following exploration wells: Canangucho -1 and Pacayaco -1ST1 on the Chaza Block, San Angel -1001 on the Magdalena Block, Taruka -1 on the Piedemonte Sur Block and Rumiyaco -1 on the Rumiyaco Block. These wells were plugged and abandoned in 2011. We also drilled the Brillante SE -2 development well on the Sierra Nevada Block, but no reservoir was present, so the well was plugged and abandoned. We also completed a 275 square kilometer 3D seismic survey. Approximately 222 square kilometers of data was acquired in the Sierra Nevada license and 53 square kilometers in the Magdalena license.

Capital expenditures in Colombia for the year ended December 31, 2010 amounted to $105.5 million and included: Costayaco facilities and site preparation and drilling for Costayaco -11, -12 and -13, Moqueta -1, -2, -3 and -4, Pacayaco -1ST1 and Canangucho -1; Juanambu -2 drilling and facilities, Taruka -1, Popa -3 drilling and 3D and 2D seismic.

Outlook - Colombia

The 2012 capital program in Colombia is $182 million with $104 million allocated to drilling, $27 million to facilities and pipelines and $51 million for G&G expenditures. Our planned work program for 2012 includes the following:

Exploration Activities

The 2012 exploration program in Colombia includes four gross exploration wells. Our oil exploration drilling program will target prospects in the Putumayo and Llanos basins. The Ramiriqui-1 oil exploration well on the Llanos-22 Block operated by CEPSA began drilling in the fourth quarter of 2011. The mirador formation has been interpreted as oil bearing. Casing has been set and drilling is continuing in order to evaluate deeper potential reservoirs. We plan to perform testing after the completion of drilling.

We plan to drill the Bordon -1 oil exploration well to the north of the Melero and Jilguero discoveries on the Garibay Block, the Verdeyaco -1 oil exploration well on the Guayuyaco Block and the La Vega Este-1 oil exploration well on the Azar Block.

Development and Delineation Activities

The 2012 development program in Colombia includes seven gross development wells. Our development drilling will focus on the Moqueta, Costayaco and Brillante field developments. In the Costayaco field, we plan to drill two additional water injector wells along with two production wells. In the Moqueta field, we plan to drill one development well, which could be used as an oil producer or water injector depending on the well results, and a further water injector well. We also plan to drill the
Brillante -3 natural gas delineation well in the Sierra Nevada Block.

Facilities and Equipment

Facilities work will include continued electrification of the Moqueta fields, water injection facilities and a production battery at the Jilguero oil discovery.

G&G

G&G work will consist of 3D and 2D seismic planned for the Cauca -6, Cauca -7, Moqueta, Garibay, Piedemonte Norte, Piedemonte Sur, Putumayo -1 and Putumayo -10 Blocks to mature leads and prospects for drilling in 2013 and beyond

Table of Contents

Segmented Results – Argentina

Segmented Results of Operations - Argentina (Thousands of U.S. Dollars)	Year Ended December 31, 2011	% Change	2010	% Change	2009
Oil and natural gas sales	$ 48,016	243	$ 13,984	1	$ 13,795
Interest income	66	154	26	(80)	127
	48,082	243	14,010	1	13,922
Operating expenses	27,076	207	8,808	17	7,537
DD&A expenses	45,506	55	29,416	253	8,339
G&A expenses	7,805	172	2,868	24	2,318
Foreign exchange (gain) loss	330	100	165	493	(42)
	80,717	96	41,257	127	18,152
Loss before income taxes	$ (32,635)	(20)	$ (27,247)	(544)	$ (4,230)
Production					
Oil and NGL's, bbl	726,762	156	284,044	(16)	337,316
Natural gas, Mcf	1,143,576	-	-	-	-
Total production, BOE (1)	917,358	223	284,044	(16)	337,316
Average Prices					
Oil and NGL's per bbl	$ 61.10	24	$ 49.23	20	$ 40.90
Natural gas per Mcf	$ 3.16	-	$ -	-	$ -
Segmented Results of Operations per BOE					
Oil and natural gas sales	$ 52.34	6	$ 49.23	20	$ 40.90
Interest income	0.07	(22)	0.09	(76)	0.38
	52.41	6	49.32	19	41.28
Operating expenses	29.52	(5)	31.01	39	22.34
DD&A expenses	49.61	(52)	103.56	319	24.72
G&A expenses	8.51	(16)	10.10	47	6.87
Foreign exchange (gain) loss	0.36	(38)	0.58	(583)	(0.12)
	88.00	(39)	145.25	170	53.81
Loss before income taxes	$ (35.59)	(63)	$ (95.93)	666	$ (12.53)

(1) Production represents production volumes NAR adjusted for inventory changes. Gas volumes are converted to BOE equivalent at the rate of six Mcf of gas per barrel of oil, based upon the approximate relative energy

content of gas and oil, which rate is not necessarily indicative of the relationship of oil and gas prices.

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.

Table of Contents

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 Argentinean 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 Argentine 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 Argentine 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 Argentine 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 $81.28 per BOE 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.

Segmented Results of Operations – Argentina for the Year Ended December 31, 2010 Compared with the Results for the Year Ended December 31, 2009

For the year ended December 30, 2010, loss before income taxes in Argentina was $27.2 million compared with $4.2 million in 2009 due to lower production levels and increased operating, depletion and G&A expenses, only partially offset by increased oil prices. Operating expenses increased due primarily to costs associated with Valle Morado, which had limited operating costs in 2009, prior to re-entry in the third quarter of 2010. DD&A included charges for ceiling test impairment of the Argentina cost center of $23.6 million in 2010 and $1.9 million in 2009. General and administrative expenses increased due to an increase in staffing and consulting fees over 2009 levels.

Crude oil and NGL production, net after 12% royalties, decreased 16% to 0.3 mmbbl in 2010 compared with 2009. The decrease resulted from general production declines.

Capital Program - Argentina

Capital expenditures in Argentina amounted to $36.3 million in 2011. Capital expenditures in 2011 included drilling expenditures of $27.1 million, facilities expenses of $4.0 million, G&G expenses of $2.6 million and other expenditures of $2.6 million. These expenditures were partially offset by proceeds of $3.3 million from the farm out of a property and $1.2 million from the sale of a blow-out preventer. The Petrolifera acquisition added interests in seven blocks in the Neuquen Basin in Argentina of which we still hold six.

The significant elements of our 2011 Capital Program in Argentina were as follows:

- Puesto Morales Block (100% working interest and Operator)

We completed drilling a development well in the Puesto Morales field, with the purpose of improving recovery and growing production from this mature oil field. We completed workovers on 18 wells and completed G&G work to optimize the location of the planned development wells. We also continued facility upgrades.

- Puesto Morales Este Block (100% working interest and Operator)

We drilled and completed two producing development wells.

- Rinconada Norte Block (35% non-operated working interest)

Our partner commenced drilling four gross exploration wells. Two wells were completed in 2011, which resulted in an oil discovery, and two were in progress at year-end. A wholly-owned subsidiary of America Petrogas Inc. is the operator of this block with a 65% working interest upon completing certain work program obligations, while we hold a 35% working interest.

- Rinconada Sur Block (100% and operator)

We started drilling one development well.

Table of Contents

- Surubi Block (85% working interest and operator)

We performed site preparation work for the Proa -2 development well and associated facilities to produce the new well and completed workover activities at the Proa -1 discovery well.

- El Chivil Block

We completed a workover program in El Chivil which helped stabilize production.

- Palmar Largo Block (14% non-operated working interest

One gross development well was drilled and workover activities were completed.

- Santa Victoria Block (50% working interest and Operator

We successfully farmed out a 50% interest in the Santa Victoria Block in the Noroeste Basin of northwestern Argentina to Apache in March 2011. The joint venture, with Gran Tierra as operator, is evaluating the gas potential of the acreage, with gas-condensate reserves and production proven in the region. We have agreed to proceed with Apache into the second exploration phase, which has a work commitment that will be fulfilled with one exploration well expected to be drilled before year-end 2012.

- Valle Morado Block (96.6% working interest and Operator)

The sidetrack drilling operation on the Valle Morado GTE.St.VMor-2001 well was suspended in February 2011 and the wellbore was abandoned due to operational challenges.

We also continued to evaluate other blocks and bids for potential acquisitions.

Capital expenditures for the year ended December 31, 2010 amounted to $33.9 million and included exploratory seismic in the Santa Victoria Block for $3.9 million, a $2.7 million workover in El Chivil and $24.4 million related to the re-entry and sidetrack of the GTE.St.VMor-2001 well, including $2.0 million to buy out our partner’s option to back in for an additional working interest.

Capital expenditures for the year ended December 31, 2009 amounted to $4.5 million mainly related to workovers, facility construction, and seismic acquisition.

Outlook – Argentina

The 2012 capital program in Argentina is $53 million with $39 million allocated to drilling, $6 million to facilities and pipelines, and $8 million to G&G expenditures.

Our planned work program for 2012 includes drilling three gross exploration wells, 10 gross development wells and conducting 14 workovers on existing wells in Argentina. Eight gross development wells are planned for the Puesto Morales Field, one on the Surubi Block and one on the Rinconada Sur Block. The intention of the drilling program is to improve recovery of oil in place and grow production. We plan to drill two oil exploration wells on the Rinconada Sur Block and are also evaluating the potential to drill a gas exploration well in the Santa Victoria Block in 2012.

Segmented Results - Peru

	Year Ended December 31,				
	2011	% Change	2010	% Change	2009
Results of Operations - Peru (Thousands of U.S. Dollars)					
Interest income	$140	-	$-	-	$-
Operating expenses	322	55	207	149	83
DD&A expenses	42,035	-	40	-	-
G&A expenses	4,249	269	1,153	272	310
Foreign exchange (gain) loss	(217)	(823)	30	900	3
	46,389	-	1,430	261	396
Loss before income taxes	$(46,249)	-	$(1,430)	261	$(396)

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

Due to the significance of losses before income taxes, Peru became a reportable segment in 2011. The comparative amounts for 2010 were disaggregated from the “All Other” category for presentation purposes.

DD&A expenses in 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.

The increase in G&A expenses in 2011 from 2010 was due to higher salaries, stock-based compensation and consulting fees resulting from increased activity. We are now the operator of three exploration blocks in Peru and have a non-operated interest in two other blocks.

Table of Contents

Capital Program – Peru

The Petrolifera acquisition added three blocks in the Ucayali Basin in Peru: Block 106, Block 107 and Block 133. Prior to close of the acquisition, Petrolifera, in consultation with Gran Tierra, notified PeruPetro of the intention not to proceed to the next exploration phase in Block 106. Accordingly, the Block 106 license agreement was terminated in April 2011.

Capital expenditures in Peru during the year ended December 31, 2011 were $36.2 million. The significant elements of our 2011 Capital Program in Peru were as follows:

- Blocks 123, 124 and 129 (20% non-operated working interest)

In September 2010, we acquired a 20% non-operated working interest in ConocoPhillips operated Block 123, Block 124 and Block 129, subject to government approval. The approval for these blocks was granted in March 2011 with final assignment completed on April 26, 2011. We relinquished our interest in Block 124 during 2011. We acquired 910 kilometers of 2D seismic data on these blocks in 2011.

- Blocks 107 and 133 (100% working interest and operator)

Permitting for drilling on Block 107 was advanced. G&G studies are ongoing on the adjacent Block 133 in preparation for seismic geophysical acquisition in 2012.

- Blocks 122 and 128

We drilled the Kanatari -1 exploration well on Block 128 which was plugged and abandoned. We relinquished our interest in Blocks 122 and 128 during 2011.

Capital expenditures in Peru during the year ended December 31, 2010 were $15.0 million and mainly related to the acquisition of seismic data, a $2.0 million deposit on the farm-in of Block 95 in Peru and commencement of drilling on Blocks 122 and 128.

Capital expenditures in Peru during the year ended December 31, 2009 were $1.6 million and included drilling feasibility and geological studies on Block 122 and Block 128.

Outlook - Peru

The Peru budget of $62 million includes drilling one gross exploration well on Block 95 and preparations for drilling a second exploration well in 2013. Drilling costs are anticipated to be $41 million and approximately $21 million is budgeted for seismic acquisition and facility costs.

On January 17, 2012, PeruPetro signed the assignment documents for Block 95, officially transferring 60% of the block to Gran Tierra. A drilling location has been identified for the first exploration well on Block 95, with civil construction initiated. Drilling is expected to be undertaken in 2012.

Results - Corporate Activities and Operations in Brazil

	Year Ended December 31,				
	2011	% Change	2010	% Change	2009

Results of Operations - Corporate Activities and Operations in Brazil (Thousands of U.S. Dollars)					
Oil and natural gas sales	$4,176	-	$-	-	$-
Interest income	518	(25)	688	39	494
	4,694	582	688	39	494
Operating expenses	1,018	-	-	(100)	73
DD&A expenses	2,561	558	389	25	311
G&A expenses	23,219	11	21,004	60	13,148
Financial instruments (gain) loss	(1,522)	-	(44)	123	190
Gain on acquisition	(21,699)	-	-	-	-
Foreign exchange (gain) loss	1,502	219	(1,258)	291	(322)
	5,079	(75)	20,091	50	13,400
Loss before income taxes	$(385)	(98)	$(19,403)	50	$(12,906)

Results of Operations – Corporate Activities and Operations in Brazil for the Year Ended December 31, 2011 Compared with the Results for the Years Ended December 31, 2010 and December 31, 2009

Corporate activities include costs associated with our headquarters in Calgary, Alberta, Canada, and expenses related to technical reviews, business development and compliance and reporting under securities regulations.

Oil and natural gas sales and operating expenses represent sales and operating expense from Block 155 in the onshore Recôncavo Basin of Brazil. We began earning revenue from this block on June 15, 2011, the date regulatory approval was received for the purchase of our 70% participating interest in that block.

Table of Contents

DD&A expenses in 2011 of $ 2.6 million included $1.8 million in Brazil. This related primarily to Block 155 which began production during the year.

The increase in G&A expenses of $ 2.2 million between 2011 and 2010 related to increased salary and stock-based compensation expense and increased consulting charges due to expanded operations in all countries. The 2011 expenses included $1.2 million related to the acquisition of Petrolifera. The increase between 2009 and 2010 was due to increased staffing levels to support business development activities and expanded operations and Brazil as well as higher stock based compensation expense due to increased stock option grants.

The financial instruments gain in 2011 primarily related to the fair value of warrants issued in connection with the acquisition of Petrolifera. These warrants expired unexercised during August 2011. In 2010, we recorded a gain of $44,000 compared with a loss of $0.2 million in 2009. We had no derivative contracts outstanding at December 31, 2011 or 2010.

The gain on acquisition related to the acquisition of Petrolifera. The gain reflected the impact on Petrolifera's pre-acquisition market value of their lack of liquidity and capital resources required to maintain production and reserves and further develop and explore their inventory of prospects.

The foreign exchange loss resulted from the translation of foreign currency denominated transactions to U.S. dollars.

Capital Program – Corporate and Brazil

Capital expenditures in Corporate and Brazil during the year ended December 31, 2011 were $52.6 million and included $28 million for the acquisition of a 70% participating interest in four blocks in the onshore Recôncavo Basin of Brazil, drilling of two exploration and one delineation wells, seismic and site preparation expenses and the cost of drilling materials for future wells.

We hold interests in four blocks in the onshore Recôncavo Basin and one block in the offshore Camamu-Almada Basin. The significant elements of our 2011 Capital Program in Brazil were as follows:

- Blocks 129, 142, 155 and 224, Recôncavo Basin (70% working interest and Operator)

On June 15, 2011, we received final approvals for the acquisition of a 70% participating interest in Blocks 129, 142, 155 and 224 in the onshore Recôncavo Basin of Brazil and also became the operator of these blocks effective from that date. With the exception of one block which has a producing well, the remaining blocks are unproved properties. First production contribution from the producing block was recorded in June 2011.

We drilled two gross exploration wells, 1-GTE-01-BA and 1-GTE-02-BA, on Blocks 142 and 129, respectively and an appraisal well, 3-GTE-03-BA on Block 155, was spud in December 2011. Drilling of the 1-GTE-01-BA vertical pilot exploration well was completed in November 2011. Core samples were acquired from the prospective reservoir section of the pilot well and we plan to drill a horizontal sidetrack in mid-2012 to test the productivity of light oil sandstone reservoir targets. Drilling of the 1-GTE-02-BA exploration well is suspended while plans are finalized for drilling a horizontal leg in mid-2012. Drilling of the 3-GTE-03-BA delineation well began on December 1, 2011 to further develop the existing discovery on Block REC-T-155. Oil bearing reservoir intervals were encountered and we are moving forward with plans to complete and place this well on production.

We also acquired 35 square kilometers of 3D seismic on Block 155.

-

BM-CAL-7 Block, Camamu Basin (10% non-operated working interest; Petrobras 60% is the operator; Statoil 30%;)

We purchased 1,366 square kilometers of an existing 3D seismic survey for the evaluation of the block.

- BM-CAL-10 Block, Camamu Basin (15% non-operated working interest; Statoil 45% is the operator; Petrobras 40%)

The ANP has announced the 1-STAT-7-BAS exploration well drilling has been completed after reaching a total measured depth of 3,651 meters. Contractually, we are restricted from discussing the well results. In accordance with the terms of the farmout agreement, we gave notice to Statoil that we will 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 farmout agreement has terminated and we will not receive any interest in Block BM-CAL-10.

Capital expenditures in the comparative periods of 2010 of $22.6 million included a $8.0 million refundable deposit on the Brazil farm-in, $4.4 million non-refundable expenditures relating to capital commitments on the Brazil farm-in, and $2.0 million of general corporate assets.

Capital expenditures in the year ended December 31, 2009 of $0.6 million related to leasehold improvements and the purchase of office furniture and equipment for our headquarters in Calgary.

Outlook – Corporate and Brazil

The 2012 capital program in Brazil is $68 million with $62 million allocated to drilling, $3 million to facilities and pipelines and $3 million to G&G expenditures. We plan to drill two gross exploration pilot wells onshore which will be followed by drilling three horizontal sidetracks, including one from the recently completed 1-GTE-01-BA pilot hole and one gross development well. Including the cost of the recent offshore well on Block BM-CAL-10, the exploration portion of the budget is expected to be $62 million. The 2012 development program in Brazil includes one gross development well. Our development drilling program will focus on Recôncavo Basin. Approximately $3 million is intended to be dedicated to pipelines and facilities and an additional $3 million for G&G work. Planned facilities work includes additional tankage, pipelines and gas facilities on Block 155.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2011, we had cash and cash equivalents of $351.7 million compared with $355.4 million at December 31, 2010, and $270.8 million at December 31, 2009.

Table of Contents

We believe that our cash position and cash generated from operations will provide us with sufficient liquidity to meet our strategic objectives and planned capital program for at least the next 12 months. 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 with the highest 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.

We believe that we have sufficient available cash and cash flow from operations to cover our expected funding needs on both a short-term and long-term basis. If the need were to arise, we believe that we could access short-term debt markets, to fund our short-term requirements and to ensure near-term liquidity. We regularly monitor the credit and financial markets and, in the future, may issue long-term debt to further improve our liquidity and capital resources. Our long-term financing strategy is to maintain the ability to access debt markets to accommodate our long term growth strategy.

At December 31, 2011, 91% 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. We do not intend to repatriate funds, but if we did we would have to accrue and pay taxes.

Effective July 30, 2010, 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 Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 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. At December 31, 2011, we had not drawn down any amounts under this facility.

As part of the acquisition of Petrolifera, we assumed a reserve backed credit facility with outstanding balance as at the acquisition date of $31.3 million. The outstanding balance was repaid when the Argentine restriction preventing its repayment expired on August 5, 2011. The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries.

Cash Flows

During the year ended December 31, 2011, our cash and cash equivalents decreased by $3.7 million as a result of cash used in investing activities of $311.7 million and cash used in financing activities of $49.0 million, partially offset by cash provided by operating activities of $356.9 million.

Net cash provided by operating activities in 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 the expanded operations. Cash outflows from investing activities in 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 and $7.7 million cash acquired through the Petrolifera acquisition. Cash outflows from financing activities in 2011 included repayment of $31.3 million of bank debt and $22.8 million of an ABCP line of credit, partially offset by $5.1 million related to proceeds from issuance of common shares. Both the bank debt and the ABCP line of credit were acquired through the Petrolifera acquisition.

During the year ended December 31, 2010, our cash and cash equivalents increased by $84.6 million as cash inflows from operations of $203.8 million and proceeds from issuance of common shares of $24.8 million more than offset cash outflows for capital expenditures of $152.3 million. 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.

During the year ended December 31, 2009, our cash and cash equivalents increased by $94.0 million as cash inflows from operations of $165.5 million and proceeds from issuance of common shares of $4.9 million more than offset cash outflows for capital expenditures of $80.9 million. Net cash provided by operating activities in 2009 was affected by the significant increase in oil production partially offset by the decrease in oil prices and increase in receivables related to oil sales.

Off-Balance Sheet Arrangements

As at December 31, 2011, 2010 and 2009 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, 2011.

	As at December 31, 2011 Payments Due in Period				
	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
Contractual Obligations (Thousands of U.S. Dollars)					
Oil transportation services	$38,059	$13,280	$8,029	$7,100	$9,650
Drilling and geological and geophysical	41,034	39,550	1,484	-	-
Completion	23,053	15,273	7,780	-	-
Facility construction	32,195	15,673	16,522	-	-
Operating leases	7,798	4,567	2,779	452	-
Software and telecommunication	3,196	2,587	609	-	-
Consulting	897	843	54	-	-
Total	$146,232	$91,773	$37,257	$7,552	$9,650

Table of Contents

At December 31, 2011, we had also provided promissory notes totalling $20.7 million as security for letters of credit relating to work commitment guarantees contained in exploration contracts.

Contractual commitments have increased from December 31, 2010 mainly as a result of new pipeline transportation contract commitments and compressor and other operating equipment leases assumed upon the acquisition of Petrolifera.

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 runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,300 per month plus approximately $4,500 for operating and other expenses, the terms are consistent with market conditions in the Calgary, Alberta, Canada real estate market.

On August 3, 2010, we entered into a contract related to the Peru drilling program with a company of which one of our directors is a shareholder and director. For the year ended December 31, 2011, $2.8 million was capitalized (December 31, 2010: $0.8 million)

On February 1, 2009, we entered into a sublease for office space with a company, of which one of our 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. The terms of the sublease were consistent with market conditions in the Calgary, Alberta, Canada real estate market.

Subsequent Events

On February 17, 2012, in accordance with the terms of a farmout agreement, we gave notice to Statoil that we will 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 farmout agreement has terminated and we will not receive any interest in the block. Pursuant to the farmout agreement, we are obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to the well that was drilled during the term of the farmout agreement. We expect to make that payment in the approximate amount of $26 million in March 2012.

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 U.S. Securities and Exchange Commission ("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, 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.

Table of Contents

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 audited 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, 2011 ceiling tests were based on wellhead prices as of the first day of each month within that twelve month period of $95.20 for Colombia, $54.26 for Argentina and $97.07 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, 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 Argentine 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 centre 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 Argentine proved reserves and a decrease in reserve volumes. We assessed our oil and gas properties for impairment as at December 31, 2009 and found that an impairment write-down of $1.9 million was required for our Argentina cost center.

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, geological and geophysical evaluations, the assignment of proved reserves, availability of capital, and other factors. For prospects 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 asset retirement obligations (“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.

Table of Contents

Allocation of Consideration Transferred in Business Combinations

The acquisition of Petrolifera was accounted for using the purchase 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 and we test goodwill for impairment at least annually. The impairment test requires allocating goodwill and certain other assets and liabilities to a level of reporting referred to as a reporting unit. We compare 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 relate to the valuation of our property and equipment. Because quoted market prices are not available for our reporting units, fair values of reporting units are based upon estimated future cash flows of the reporting unit.

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.

The goodwill on our balance sheet resulted from the Solana and Argosy Energy International L.P. Argosy acquisitions, and relates entirely to the Colombia reporting unit. This reporting unit is not at risk of failing the “Step 1” goodwill impairment test under GAAP. The calculated fair value of the Colombian reporting unit is significantly in excess of its carrying value.

Differences in the our actual future cash flows, operating results, growth rates, capital expenditures, cost of capital and discount rates as compared with the estimates utilized for the purpose of calculating the fair value of each business unit, as well as a decline in our stock price and related market capitalization, could affect the results of our annual goodwill assessment and, accordingly, potentially lead to future goodwill impairment charges.

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.

Table of Contents

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 common stock. 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.

Item 7A. Quantitative and Qualitative Disclosure about Market Risk

Our principal market risk relates to oil prices. Most of our revenues are from oil sales at prices which are defined by contract relative to WTI and adjusted for transportation and 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. 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. The majority of our capital expenditures in Peru 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 local office expenditures 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, unrealized foreign exchange gains and losses result from the fluctuation of the U.S. dollar to the Colombian peso due to our deferred tax liability, a monetary liability, which is mainly denominated in the local currency of the Colombian foreign operations. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $94,000 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 government securities of the United States or Canadian federal governments such as Guaranteed Investment Certificates or Treasury Bills. 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.

Item 8. Financial Statements and Supplementary Data.

Table of Contents

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, 2011 and 2010, 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, 2011, and a summary of significant accounting policies and other explanatory information.

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, 2011 and 2010, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2011 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, 2011, 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 27, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 27, 2012

Table of Contents

Gran Tierra Energy Inc.
Consolidated Statements of Operations and Retained Earnings
For the Years Ended December 31, 2011, 2010 and 2009
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

	Year Ended December 31,		
	2011	2010	2009
REVENUE AND OTHER INCOME			
Oil and natural gas sales	$596,191	$373,286	$262,629
Interest income	1,216	1,174	1,087
	597,407	374,460	263,716
EXPENSES			
Operating	86,497	59,446	40,784
Depletion, depreciation, accretion and impairment (Note 6)	231,235	163,573	135,863
General and administrative	60,389	40,241	28,787
Equity tax (Note 9)	8,271	-	-
Financial instruments (gain) loss (Notes 3 and 12)	(1,522)	(44)	190
Gain on acquisition (Note 3)	(21,699)	-	-
Foreign exchange (gain) loss	(11)	16,838	19,797
	363,160	280,054	225,421
INCOME BEFORE INCOME TAXES	234,247	94,406	38,295
Income tax expense (Note 9)	(107,330)	(57,234)	(24,354)
NET INCOME AND COMPREHENSIVE INCOME	126,917	37,172	13,941
RETAINED EARNINGS, BEGINNING OF YEAR	58,097	20,925	6,984
RETAINED EARNINGS, END OF YEAR	$185,014	$58,097	$20,925
NET INCOME PER SHARE — BASIC	$0.46	$0.15	$0.06
NET INCOME PER SHARE — DILUTED	$0.45	$0.14	$0.05
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 7)	273,491,564	253,697,076	241,258,568
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 7)	281,287,002	264,304,831	253,590,103

(See notes to the consolidated financial statements)

Table of Contents

Gran Tierra Energy Inc.
Consolidated Balance Sheets
As at December 31, 2011 and 2010
(Thousands of U.S. Dollars)

	As at December 31, 2011	2010
ASSETS		
Current Assets		
Cash and cash equivalents	$ 351,685	$ 355,428
Restricted cash	1,655	250
Accounts receivable (Note 5)	69,362	43,035
Inventory (Note 5)	7,116	5,669
Taxes receivable	21,485	6,974
Prepaids	3,597	1,940
Deferred tax assets (Note 9)	3,029	4,852
Total Current Assets	457,929	418,148
Oil and Gas Properties (using the full cost method of accounting)		
Proved	618,982	442,404
Unproved	417,868	278,753
Total Oil and Gas Properties	1,036,850	721,157
Other capital assets	7,992	5,867
Total Property, Plant and Equipment (Note 6)	1,044,842	727,024
Other Long Term Assets		
Restricted cash	13,227	1,190
Deferred tax assets (Note 9)	4,747	-
Other long term assets	3,454	311
Goodwill (Note 2)	102,581	102,581
Total Other Long Term Assets	124,009	104,082
Total Assets	$ 1,626,780	$ 1,249,254
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable (Note 10)	$ 82,189	$ 76,023
Accrued liabilities (Note 10)	66,832	32,120
Taxes payable	95,482	43,832
Asset retirement obligation (Note 8)	326	338
Total Current Liabilities	244,829	152,313

Long Term Liabilities				
Deferred tax liability (Note 9)		186,799		204,570
Equity tax payable (Note 9)		6,484		-
Asset retirement obligation (Note 8)		12,343		4,469
Other long term liabilities		2,007		1,036
Total Long Term Liabilities		207,633		210,075
Commitments and Contingencies (Note 11)				
Subsequent Events (Note 15)				
Shareholders' Equity				
Common shares (Note 7) (262,304,249 and 240,440,830 common shares and 16,323,819 and 17,681,123 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2011 and 2010, respectively)		7,510		4,797
Additional paid in capital		980,014		821,781
Warrants (Note 7)		1,780		2,191
Retained earnings		185,014		58,097
Total Shareholders' Equity		1,174,318		886,866
Total Liabilities and Shareholders' Equity	$	1,626,780	$	1,249,254

(See notes to the consolidated financial statements)

Table of Contents

Gran Tierra Energy Inc.
Consolidated Statements of Cash Flows
For the Years Ended December 31, 2011, 2010 and 2009
(Thousands of U.S. Dollars)

	Year Ended December 31, 2011	2010	2009
Operating Activities			
Net income	$126,917	$37,172	$13,941
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, accretion and impairment (Note 6)	231,235	163,573	135,863
Deferred taxes (Note 9)	(29,222)	(20,090)	(15,355)
Stock-based compensation (Note 7)	12,767	8,025	5,309
(Gain) loss on financial instruments (Notes 3 and 12)	(1,354)	(44)	277
Unrealized foreign exchange (gain) loss	(1,695)	14,786	19,496
Settlement of asset retirement obligation (Note 8)	(345)	(286)	(52)
Equity tax	2,442	-	-
Gain on acquisition (Note 3)	(21,699)	-	-
Net changes in non-cash working capital			
Accounts receivable	(15,627)	(5,323)	(27,926)
Inventory	(548)	(1,221)	(1,849)
Prepaids	(1,321)	(120)	(717)
Accounts payable and accrued liabilities	19,918	(3,212)	36,875
Taxes receivable and payable	35,422	10,522	(409)
Net cash provided by operating activities	356,890	203,782	165,453
Investing Activities			
Restricted cash	(10,197)	352	(1,792)
Additions to property, plant and equipment	(333,194)	(152,299)	(80,932)
Proceeds from disposition of oil and gas properties (Note 6)	4,450	7,986	5,400
Cash acquired on acquisition (Note 3)	7,747	-	-
Proceeds on sale of asset-backed commercial paper (Note 3)	22,679	-	-
Long term assets and liabilities	(3,138)	36	968
Net cash used in investing activities	(311,653)	(143,925)	(76,356)
Financing Activities			
Settlement of bank debt (Notes 3 and 13)	(54,103)	-	-
Proceeds from issuance of common shares	5,123	24,785	4,935
Net cash (used in) provided by financing activities	(48,980)	24,785	4,935
Net (decrease) increase in cash and cash equivalents	(3,743)	84,642	94,032
Cash and cash equivalents, beginning of year	355,428	270,786	176,754
Cash and cash equivalents, end of year	$351,685	$355,428	$270,786

Cash	$172,645	$272,151	$182,197
Term deposits	179,040	83,277	88,589
Cash and cash equivalents, end of year	$351,685	$355,428	$270,786
Supplemental cash flow disclosures:			
Cash paid for interest	$1,604	$-	$-
Cash paid for taxes	$67,053	$49,088	$31,527
Non-cash investing activities:			
Non-cash working capital related to property, plant and equipment	$43,333	$48,640	$17,972

(See notes to the consolidated financial statements)

Table of Contents

Gran Tierra Energy Inc.
Consolidated Statements of Shareholders' Equity
For the Years Ended December 31, 2011, 2010 and 2009
(Thousands of U.S. Dollars)

	Year Ended December 31, 2011	2010	2009
Share Capital			
Balance, beginning of year	$4,797	$1,431	$226
Issue of common shares	2,713	3,366	1,205
Balance, end of year	7,510	4,797	1,431
Additional Paid in Capital			
Balance, beginning of year	821,781	766,963	754,832
Issue of common shares	142,109	19,119	2,650
Exercise of warrants (Note 7)	411	24,916	2,777
Exercise of stock options (Note 7)	1,990	2,300	1,080
Stock-based compensation expense (Note 7)	13,723	8,483	5,624
Balance, end of year	980,014	821,781	766,963
Warrants			
Balance, beginning of year	2,191	27,107	29,884
Exercise of warrants (Note 7)	(411)	(24,916)	(2,777)
Balance, end of year	1,780	2,191	27,107
Retained Earnings			
Balance, beginning of year	58,097	20,925	6,984
Net income	126,917	37,172	13,941
Balance, end of year	185,014	58,097	20,925
Total Shareholders' Equity	$1,174,318	$886,866	$816,426

(See notes to the consolidated financial statements)

Table of Contents

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2011, 2010 and 2009
Expressed in U.S. Dollars, unless otherwise stated

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 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. Letters of credit currently secured by cash relate to work commitment guarantees contained in exploration contracts. Restricted cash is classified between current and long term assets based on the expiration dates of the letters of credit.

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, 2011 and 2010.

Inventory

Inventory consists of oil in tanks 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.

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.

Table of Contents

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 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 implemented the SEC final rule “Modernization of Oil and Gas Reporting” at December 31, 2009 and calculates future net cash flows by applying the 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 prospects 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 and is tested for impairment at least annually unless business events indicate an impairment test is required more frequently. 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 annual impairment tests of goodwill at December 31, 2011 and 2010. Based on these assessments, no impairment of goodwill was identified.

Revenue recognition

Revenue from the production of oil and natural gas is recognized when title passes to the customer and when collection of the revenue is reasonably assured. For the Company’s Colombian operations, Gran Tierra’s customers take title when the oil is transferred to their pipeline. 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.

Table of Contents

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 stock. 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 (Note 12). In connection with the acquisition of Solana in November 2008, the Company recorded the fair value of warrants assumed of $23.6 million as part of the consideration paid for the acquisition. The Company determines 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 common shares issued and outstanding during each period. Diluted net income per share is calculated by adjusting the average number of common shares outstanding for the dilutive effect, if any, of common stock equivalents. The Company uses the treasury stock method to determine the dilutive effect. This method assumes that all common share 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 common shares of the Company at the average trading price of common shares during the period.

Adopted accounting pronouncements

Stock Compensation

In April 2010, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2010-13, "Compensation–Stock Compensation (Topic 718)." The update clarifies that an employee share-based payment award with an exercise price denominated in the currency of a market in which a substantial portion of the entity’s equity securities trades should not be considered to contain a condition that is not a market, performance, or service condition. Therefore, an entity would not classify such an award as a liability if it otherwise qualifies as equity. This ASU was effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2010. The implementation of this update did not materially impact the Company’s consolidated financial position, results of operations or cash flows.

Business Combinations

In December 2010, the FASB issued ASU 2010-29, "Business Combinations (Topic 850), Disclosures of Supplementary Pro Forma Information for Business Combinations." The update is intended to conform reporting of pro forma revenue and earnings for material business combinations included in the notes to the financial statements and expand disclosure of non-recurring adjustments that are directly attributable to the business combination. The pro forma revenue and earnings of the combined entity are presented as if the acquisition had occurred as of the beginning of the annual reporting period. If comparatives are presented, the pro forma disclosures for both periods presented should be reported as if the acquisition had occurred as of the beginning of the comparable prior annual reporting period only. This ASU was effective for business combinations for which the acquisition date was on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The disclosure requirements of this ASU have been adopted by the Company.

Recently issued accounting pronouncements

Goodwill

In September 2011, the FASB issued 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 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2011.The implementation of this update is not expected to materially impact the Company’s consolidated financial position, results of operations or cash flows.

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 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.

Table of Contents

3. Business Combination

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 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 Gran Tierra common shares, 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 million.

The fair value of Gran Tierra's common shares was determined as the closing price of the common shares 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 financial instruments gain reflected in the consolidated statement of operations for the year ended December 31, 2011, includes a $1.3 million gain arising from the fair value of the expired Replacement Warrants.

The acquisition is 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:	
Common shares 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 is reported as “Gain on acquisition”, in the consolidated statement of operations. The gain reflects 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 the expiry of the Replacement Warrants, the financial instruments gain for the year ended December 31, 2011 was $1.5 million.

Table of Contents

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 (Note 13). The amount outstanding under this credit facility was included as part of net working capital in the allocation of consideration transferred. This credit facility was repaid during August 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.

Pro forma results for the years ended December 31, 2011 and 2010 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	2010
Revenue and other income	$606,602	$427,137
Net income	$94,094	$7,557
Net income per share - basic	$0.34	$0.03
Net income per share - diluted	$0.33	$0.03

The supplemental pro forma earnings of Gran Tierra for the years ended December 31, 2011 and 2010 were adjusted to exclude $4.4 million of acquisition costs recorded in G&A expense and the $21.7 million gain on acquisition recognized in the 2011 results of Gran Tierra because they are 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 includes oil and natural gas sales of $32.5 million from Petrolifera for the period subsequent to the Acquisition Date. Petrolifera incurred an after tax loss of $8.0 million in the period since the Acquisition Date.

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 and Peru based on a geographic organization. The Company's operations in Brazil are not a reportable segment because the level of activity in Brazil was not significant at December 31, 2011. During the three months ended March 31, 2011, Peru became a reportable segment due to the significance of its loss before income taxes compared with the consolidated results of operations. Prior year segmented disclosure has been conformed to this presentation with the Peru reportable segment's results and asset information disaggregated from the "All Other" category. The All Other category represents the Company's corporate activities and operations in Brazil.

The accounting policies of the reportable segments are the same as those described in Note 2. The Company evaluates segment performance based on income or loss before income taxes. The results of the Colombia, Argentina and Peru reportable segments include the operations of Petrolifera subsequent to March 18, 2011, the date of acquisition of Petrolifera (Note 3).

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

	Year Ended December 31, 2011				
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$ 543,999	48,016	-	4,176	$ 596,191
Interest income	492	66	140	518	1,216
DD&A expenses	141,133	45,506	42,035	2,561	231,235
DD&A - per unit of production	26.17	49.61	-	59.48	36.39
Income (loss) before income taxes	313,516	(32,635)	(46,249)	(385)	234,247
Segment capital expenditures (1)	$ 202,551	36,289	36,224	52,583	$ 327,647

Table of Contents

(Thousands of U.S. Dollars except per unit of production amounts)	Year Ended December 31, 2010 Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$ 359,302	$ 13,984	$ -	$ -	$ 373,286
Interest income	460	26	-	688	1,174
DD&A expenses	133,728	29,416	40	389	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)	(19,403)	94,406
Segment capital expenditures (1)	$ 105,482	$ 33,930	$ 15,029	$ 22,598	$ 177,039

(Thousands of U.S. Dollars except per unit of production amounts)	Year Ended December 31, 2009 Colombia	Argentina	Peru	All Other	Total
Oil and natural gas sales	$ 248,834	$ 13,795	$ -	$ -	$ 262,629
Interest income	466	127	-	494	1,087
DD&A expenses	127,213	8,339	-	311	135,863
DD&A - per unit of production	29.64	24.72	-	-	29.35
Income (loss) before income taxes	55,827	(4,230)	(396)	(12,906)	38,295
Segment capital expenditures (1)	$ 81,364	$ 4,532	$ 1,606	$ 622	$ 88,124

(1) Net of proceeds from the farm out of a 50% interest in the Santa Victoria Block and the sale of a blow-out preventer in Argentina in 2011 (see Note 6), the Garibay overriding royalty in Colombia in 2010 (see Note 6) and the Guachiria Blocks in Colombia in 2009 (see 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.

In 2011, the Company had one significant customer for its Colombian oil, Ecopetrol S.A. ("Ecopetrol"). Sales to Ecopetrol accounted for 87%, 96% and 94% of the Company's revenues in 2011, 2010 and 2009, respectively. In 2011 in Argentina, the Company had three significant customers, Refineria del Norte S.A ("Refiner"), Shell C.A.P.S.A. ("Shell") and YPF S.A. ("YPF"). Sales to Shell, Refiner and YPF accounted for 3%, 3% and 2% respectively of the Company's oil and natural gas sales in 2011. Sales to Refiner accounted for 4% and 6% of the Company's revenues in 2010 and 2009.

During the year ended December 31, 2011, interest expense of $1.6 million was recorded in G&A in Argentina (2010 and 2009 – nil).

(Thousands of U.S. Dollars)	As at December 31, 2011 Colombia	Argentina	Peru	All Other	Total
Property, plant and equipment	$ 816,396	129,072	34,305	65,069	$ 1,044,842

Goodwill	102,581	-	-	-	102,581
Other assets	269,843	34,672	9,597	165,245	479,357
Total Assets	$ 1,188,820	$ 163,744	$ 43,902	$ 230,314	$ 1,626,780

	As at December 31, 2010				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	All Other	Total
Property, plant and equipment	$ 654,416	$ 29,031	$ 28,578	$ 14,999	$ 727,024
Goodwill	102,581	-	-	-	102,581
Other assets	155,798	15,220	18,575	230,056	419,649
Total Assets	$ 912,795	$ 44,251	$ 47,153	$ 245,055	$ 1,249,254

Table of Contents

5. Accounts Receivable and Inventory

Accounts Receivable

(Thousands of U.S. Dollars)	As at December 31, 2011	2010
Trade	$ 45,922	$ 34,182
Other	23,440	8,853
Total	$ 69,362	$ 43,035

Inventory

Oil and supplies inventories at December 31, 2011 are $4.7 million and $2.4 million, respectively (2010 - $3.6 million and $2.1 million, respectively).

6. Property, Plant and Equipment

	As at December 31, 2011		
(Thousands of U.S. Dollars)	Cost	Accumulated DD&A	Net Book Value
Oil and natural gas properties			
Proved	$ 1,181,503	$ (562,521)	$ 618,982
Unproved	417,868	-	417,868
	1,599,371	(562,521)	1,036,850
Furniture and fixtures and leasehold improvements	6,973	(4,002)	2,971
Computer equipment	8,443	(4,174)	4,269
Automobiles	1,295	(543)	752
Total Property, Plant and Equipment	$ 1,616,082	$ (571,240)	$ 1,044,842

	As at December 31, 2010		
(Thousands of U.S. Dollars)	Cost	Accumulated DD&A	Net Book Value
Oil and natural gas properties			
Proved	$ 777,262	$ (334,858)	$ 442,404
Unproved	278,753	-	278,753
	1,056,015	(334,858)	721,157
Furniture and fixtures and leasehold improvements	5,233	(2,831)	2,402
Computer equipment	5,521	(2,358)	3,163
Automobiles	779	(477)	302
Total Property, Plant and Equipment	$ 1,067,548	$ (340,524)	$ 727,024

On August 26, 2010, the Company entered into an agreement to acquire a 70% participating interest in four blocks in Brazil. With the exception of one block which has a producing well, 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 in the All Other category of capital expenditures in 2011 and 2010. The 70% share of all benefits and costs with respect to the period between the effective date and the completion of the transaction were an adjustment to the consideration paid for the four blocks.

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 to Apache Corporation. 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 interest 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. Principal terms included consideration of $7.0 million comprising an initial cash payment of $4.0 million at closing, followed by 15 monthly installments of $200,000 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. Gran Tierra retained a 10% overriding royalty interest on the Guachiria Sur Block, which, in the event of a discovery, is designed to reimburse 200% of the Company's costs for previously acquired seismic data.

Depreciation, depletion and amortization was $163.5 million in 2011 (2010 - $140 million; 2009 - $134.0 million). In 2011, we recorded ceiling test impairment losses in the Company's Peru and Argentina cost centers of $42.0 million and $25.7 million, respectively. The 2011 impairment charge in the Peru cost center related to seismic and drilling costs from 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 Argentine proved reserves and a decrease in reserve volumes. In 2010, we recorded a $23.6 million ceiling test impairment loss in the Company's Argentina cost center as compared with a $1.9 million impairment loss for December 31, 2009. Of the 2010 impairment loss, $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. The 2009 impairment loss resulted from higher forecasted operating costs to produce the remaining proved reserves in Argentina.

The amounts capitalized in each of the Company's cost centers during the years ended December 31, 2011 and 2010 were as follows:

	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

	Year ended December 31, 2009				
(Thousands of U.S. Dollars)	Colombia	Argentina	Peru	Brazil	Total
Capitalized G&A, including stock-based compensation	$ 1,600	$ 600	$ 30	$ -	$ 2,230
Capitalized stock-based compensation	$ 198	$ 117	$ -	$ -	$ 315

Unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina, Peru and Brazil. The Company had $274.8 million (December 31, 2010 - $228.8 million) in unproved assets in Colombia, $57.0 million (December 31, 2010 - $9.4 million) of unproved assets in Argentina and $33.7 million (December 31, 2010 - $28.2 million) of unproved assets in Peru, and $52.4 million (December 31, 2010 – $12.4 million) of unproved assets in Brazil for a total of $417.9 million (December 31, 2010 - $278.8 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 following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2011:

Costs Incurred in

(Thousands of U.S. Dollars)	2011	2010	2009	Prior to 2009	Total
Acquisition costs - Colombia	$76,346	-	-	159,045	$235,391
Acquisition costs - Argentina	45,015	-	-	-	45,015
Acquisition costs - Peru	23,423	2,000	-	-	25,423
Acquisition costs - Brazil	22,891	12,395	-	-	35,286
Exploration costs - Colombia	19,233	12,427	3,311	487	35,458
Exploration costs - Argentina	181	683	163	229	1,256
Exploration costs - Peru	7,389	301	372	189	8,251
Exploration costs - Brazil	17,155	-	-	-	17,155
Development costs - Colombia	3,929	-	-	-	3,929
Development costs - Argentina	5,683	5,021	-		10,704
Total oil and natural gas properties not subject to depletion	$221,245	32,827	$3,846	$159,950	$417,868

Table of Contents

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, 2011, outstanding share capital consists of 262,304,249 common voting shares of the Company, 8,512,707 exchangeable shares of Gran Tierra Exchange Co., automatically exchangeable on November 14, 2013, and 7,811,112 exchangeable shares of Goldstrike Exchange Co., automatically exchangeable on November 10, 2012. The exchangeable shares of Gran Tierra Exchange Co, were issued upon acquisition of Solana. The exchangeable shares of Gran Tierra Goldstrike Inc. were issued upon the business combination between Gran Tierra Energy Inc., an Alberta corporation, and Goldstrike, Inc., which is now the Company. Each exchangeable share is exchangeable into one common voting share of the Company. The holders 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 common stock. Holders of exchangeable shares have substantially the same rights as holders of common voting shares.

Warrants

At December 31, 2011, the Company had 6,298,230 warrants outstanding to purchase 3,149,115 common shares for $1.05 per share, expiring between June 20, 2012 and June 30, 2012. For the year ended December 31, 2011, 735,817 common shares were issued upon the exercise of 1,471,634 warrants (year ended December 31, 2010, 11,127,527 common shares were issued upon the exercise of 15,109,116 warrants). Included in warrants exercised in 2010 were 7,145,938 warrants to purchase 7,145,938 common shares for $14.4 million, assumed in the acquisition of Solana in November 2008. The Company issued 4,125, 036 Replacement Warrants in connection with its acquisition of Petrolifera during March 2011 (Note 3). The Replacement Warrants expired unexercised during August 2011.

Stock Options

As at December 31, 2011, 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 number of shares of common stock available for issuance thereunder from 18,000,000 shares to 23,306,100 shares.

The Company grants options to purchase common shares to certain directors, officers, employees and consultants. Each option permits the holder to purchase one common share at the stated exercise 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. At the time of grant, the exercise price equals the market price. For the year ended December 31, 2011, 1,695,049 common shares were issued upon the exercise of 1,695,049 stock options (year ended December 31, 2010 – 2,895,553; year ended December 31, 2009 – 1,391,028). The following options are outstanding as of December 31, 2011:

	Number of Outstanding Options	Weighted Average Exercise Price $/Option	Number of Nonvested Options	Weighted Average Grant-Date Fair Value $/Option
Balance, December 31, 2010	10,943,058	$ 3.49	5,516,691	$ 2.68
Granted in 2011	4,215,996	7.94	4,215,996	4.84

Exercised in 2011	(1,695,049)	(2.70)	-	-
Vested in 2011	-	-	(2,940,822)	(2.26)
Forfeited in 2011	(600,003)	(6.70)	(576,669)	(4.06)
Balance, December 31, 2011	12,864,002	$ 4.90	6,215,196	$ 4.22

The weighted average grant date fair value for options granted in 2011 was $4.84 (2010 – $3.36; 2009 - $2.43). The weighted average grant date fair value for non-vested options at December 31, 2011 was $4.22 (2010 – $2.68). The weighted average grant date fair value for options vested in 2011 was $2.26 (2010 - $1.61; 2009 - $1.38). The total fair value of stock options vested during 2011 was $6.6 million (2010 - $5.1 million; 2009 - $4.7 million).

The aggregate intrinsic value of options outstanding at December 31, 2011 is $14.7 million (2010 - $49.9 million; 2009 - $39.0 million) based on the Company’s closing stock price of $4.80 at December 31, 2011 (December 31, 2010 - $8.05; December 31, 2009 - $5.73). The intrinsic value of options exercised in 2011 was $6.2 million (2010 - $12.8 million; 2009 - $2.9 million).

In 2011, the stock-based compensation expense was $13.7 million (2010 - $8.5 million; 2009 - $5.6 million) of which $11.4 million (2010 - $7.2 million; 2009 - $4.5 million) was recorded in G&A expense and $1.3 million (2010 - $0.8 million; 2009 - $0.8 million) was recorded in operating expense and $1.0 million (2010 - $0.5 million; 2009 - $0.3 million) was capitalized as part of exploration and development costs. At December 31, 2011, there was $11.7 million (2010 - $6.1 million; 2009 - $5.4 million) of unrecognized compensation cost related to unvested stock options which is expected to be recognized over the next three years.

Table of Contents

The table below summarizes stock options outstanding at December 31, 2011:

Range of Exercise Prices ($/option)	Number of Outstanding Options		Weighted Average Exercise Price $/Option	Weighted Average Expiry Years
0.50 to 2.00	1,195,837		1.12	4.6
2.01 to 3.50	4,310,250		2.47	6.8
3.51 to 5.50	621,666		4.52	8.3
5.51 to 7.00	3,132,753		5.94	8.4
7.01 to 8.40	3,603,496		8.23	9.1
Total	12,864,002	$	4.90	7.7

The table below summarizes exercisable stock options at December 31, 2011:

Range of Exercise Prices ($/option)	Number of Exercisable Options		Weighted AverageExercise Price $/Option	Weighted Average Expiry Years
0.50 to 2.00	1,195,837	$	1.12	4.6
2.01 to 3.50	4,128,583	$	2.47	6.8
3.51 to 5.50	283,332	$	4.47	7.8
5.51 to 7.00	897,721	$	5.90	8.2
7.01 to 8.40	143,333	$	7.67	7.2
Total	6,648,806	$	2.89	6.6

The aggregate intrinsic value of options exercisable at December 31, 2011 is $14.2 million (2010 - $49.4 million; 2009 - $19.8 million) based on the Company's closing stock price of $4.80 at December 31, 2011 (December 31, 2010 – $8.05; December 31, 2009 - $5.73)

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,		
	2011	2010	2009
Dividend yield (per share)	$nil	$nil	$nil
Volatility	75% to 81%	84% to 90%	94% to 98%
Weighted average volatility	80 %	89 %	96 %
Risk-free interest rate	0.4% to 1.4%	0.2% to 0.5%	0.4% to 0.6%
Weighted average risk-free interest rate	1.2 %	0.3 %	0.5 %
Expected term	4 to 6 years	3 years	3 years

Weighted average shares outstanding	Year Ended December 31,		
	2011	2010	2009
Weighted average number of common and exchangeable shares outstanding	273,491,564	253,697,076	241,258,568
Shares issuable pursuant to warrants	2,708,183	3,750,781	9,503,818
Shares issuable pursuant to stock options	5,143,498	7,402,966	5,797,322
Shares to be purchased from proceeds of stock options	(56,243)	(545,992)	(2,969,605)

Weighted average number of diluted common and exchangeable shares outstanding	281,287,002	264,304,831	253,590,103

Net income per share

At December 31, 2011, 3,726,999 (December 31, 2010 - 290,000; December 31, 2009 - 1,080,000) options to purchase common shares were excluded from the diluted income per share calculation as the instruments were anti-dilutive.

Table of Contents

8. Asset Retirement Obligation

As at December 31, 2011, the Company's asset retirement obligation was comprised of a Colombian obligation in the amount of $5.5 million (December 31, 2010 - $3.7 million), an Argentine obligation in the amount of $6.7 million (December 31, 2010 - $1.1 million) and a Brazilian obligation in the amount of $0.5 million (December 31, 2010 - nil). As at December 31, 2011, the undiscounted asset retirement obligation was $29.9 million. Revisions to estimated liabilities during the period 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 asset retirement obligations. Changes in the carrying amounts of the asset retirement obligations associated with the Company's oil and natural gas properties were as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	2011	2010
Balance, beginning of year	$4,807	$4,708
Settlements	(345)	(286)
Disposal	(172)	(720)
Liability incurred	867	719
Liability assumed in a business combination (Note 3)	4,901	-
Foreign exchange	17	58
Accretion	673	328
Revisions in estimated liability	1,921	-
Balance, end of year	$12,669	$4,807
Asset retirement obligation - current	$326	$338
Asset retirement obligation - long term	12,343	4,469
Balance, end of year	$12,669	$4,807

9. Income Taxes

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2011	2010	2009
Income before income taxes	$ 234,247	$ 94,406	38,295
	35 %	35 %	35 %
Income tax expense expected	81,986	33,042	13,403
Foreign currency translation adjustments	(417)	6,409	1,099
Impact of foreign taxes	3,890	(3,094)	(1,565)
Enhanced tax depreciation incentive	-	(7,971)	(3,380)
Stock-based compensation	4,013	2,381	1,814
Increase in valuation allowance	36,815	19,991	16,199
Branch and other foreign income pick-up in the United States and Canada	(14,363)	(3,957)	(5,931)
Non-deductible third party royalty in Colombia	8,525	5,506	3,532
Non-taxable gain on acquisition	(7,595)	-	-
Other permanent differences	(5,524)	4,927	(817)
Total income tax expense	$ 107,330	$ 57,234	$ 24,354

Current income tax	136,015	76,913	38,795
Deferred tax recovery	(28,685)	(19,679)	(14,441)
Total income tax expense	$ 107,330	$ 57,234	$ 24,354

Table of Contents

(Thousands of U.S. Dollars)	As at December 31, 2011	2010
Deferred Tax Assets		
Tax benefit of loss carryforwards	$63,910	$27,527
Tax basis in excess of book basis	17,065	7,975
Foreign tax credits and other accruals	27,164	16,895
Capital losses	2,433	1,413
Deferred tax assets before valuation allowance	110,572	53,810
Valuation allowance	(102,796)	(48,958)
	$7,776	$4,852
Deferred tax assets - current	$3,029	$4,852
Deferred tax assets - long-term	4,747	-
	7,776	4,852
Deferred Tax Liabilities		
Long-term - book value in excess of tax basis	(186,799)	(204,570)
	(186,799)	(204,570)
Net Deferred Tax Liabilities	$(179,023)	$(199,718)

As at December 31, 2011, the Company has operating loss carryforwards of $361.6 million (December 31, 2010 - $95.6 million) and capital losses of $13.7 million (December 31, 2010 – $4.0 million). Of these losses, $339.8 million (December 31, 2010 - $75.4 million) are losses generated by the foreign subsidiaries of the Company. In certain jurisdictions, the net operating loss carryforwards expire between 2012 and 2031 and the capital losses expire between 2012 and 2016, while certain other jurisdictions allow net operating losses to be carried forward indefinitely. Of the total net operating loss carryforwards, $1.2 million will begin to expire by 2012.

Equity tax for the year ended December 31, 2011 of $8.3 million 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 is expensed in the first quarter of 2011 at the commencement of the four-year period. The remainder of the equity tax liability at December 31, 2011 relates to an equity tax liability assumed upon the acquisition of Petrolifera.

As at December 31, 2011, the total amount of Gran Tierra’s unrecognized tax benefits was approximately $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, 2011, the amount of interest and penalties on unrecognized tax benefits included in current income tax liabilities in the condensed consolidated balance sheet was approximately $1.6 million. The Company had no material interest or penalties included in the consolidated statement of operations for the three years ended December 31, 2011.

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

(Thousands of U.S. Dollars)	
Unrecognized tax benefit at January 1, 2011	$ 4,175
Changes for tax positions relating to prior year	585
Additions to tax position related to the current year	15,740

Unrecognized tax benefit at December 31, 2011	$ 20,500

The Company and its subsidiaries file income tax returns in the U.S. federal and state jurisdictions and certain other foreign jurisdictions. The Company is subject to income tax examinations for the calendar tax years ended 2005 through 2011 in most jurisdictions. The Company does not anticipate any material changes to the unrecognized tax benefits disclosed above within the next twelve months.

10. Accounts Payable and Accrued Liabilities

	As at December 31,	
(Thousands of U.S. Dollars)	2011	2010
Trade	$71,384	$63,969
Royalties	37,936	18,064
VAT and withholding tax	24,962	16,438
Other	14,739	9,672
Total	$149,021	$108,143

Table of Contents

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, 2011.

	As at December 31, 2011 Payments Due in Period				
(Thousands of U.S. Dollars)	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
Oil transportation services	$38,059	$13,280	$8,029	$7,100	$9,650
Drilling and geological and geophysical	41,034	39,550	1,484	-	-
Completions	23,053	15,273	7,780	-	-
Facility construction	32,195	15,673	16,522	-	-
Operating leases	7,798	4,567	2,779	452	-
Software and telecommunication	3,196	2,587	609	-	-
Consulting	897	843	54	-	-
Total	$146,232	$91,773	$37,257	$7,552	$9,650

Gran Tierra leases certain office space, compressors, vehicles, equipment and housing. Total rent expense for 2011 was $3.0 million (2010 – $2.3 million; 2009 - $2.1 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. Management believes the resolution of these matters would not have a material adverse impact on the Company's consolidated financial position, results of operations or cash flows.

Letters of credit

At December 31, 2011, we had provided promissory notes totalling $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 $5.4 million.

Gran Tierra is subject to a third party 10% net profits interest on 50% of the Company's production from the Costayaco field that arises from the original acquisition in 2006 of 50% of Gran Tierra's interest in the Chaza Block Contract. There is currently 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 an arbitration which was heard in Texas, in accordance with the rules of the American Arbitration Association, in the fourth quarter of 2011. We expect to receive the arbitrator's decision in March 2012. 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. The disputed amount at December 31, 2011 is $9.6 million.

Gran Tierra has several lawsuits and claims pending for which the Company currently cannot determine the ultimate result. Gran Tierra records costs as they are incurred or become probable and determinable. 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.

Table of Contents

12. Financial Instruments, Fair Value Measurements and Credit Risk

At December 31, 2011 the Company's financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable and accounts payable, accrued liabilities. The fair value of long term restricted cash approximates its carrying value because interest rates are variable and reflective of market rates. The fair values of other financial instruments approximate their carrying amounts due to the short term maturity of these instruments.

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels. Level 1 inputs consist of quoted prices (unadjusted) in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs are based on significant other observable inputs and significant unobservable inputs, respectively, and have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. The Company does not have any financial assets or liabilities measured at fair value on the balance sheet at December 31, 2011.

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, 2011, cash and cash equivalents includes 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 our operating areas. Any foreign currency transactions are conducted on a spot basis, with major financial institutions in our 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. In 2011, the Company had one significant customer for its Colombian oil, Ecopetrol, and in Argentina the Company had three significant customers, Refiner, Shell and YPF.

Additionally, foreign exchange gains and losses mainly result from fluctuation of the U.S. dollar to the Colombian peso due to Gran Tierra's deferred tax liability, a monetary liability, which is 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 US dollar functional currency. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $94,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

The Company holds no derivative instruments at December 31, 2011 or 2010 and does not use derivative financial instruments for speculative purposes. The Replacement Warrants (Note 3) met the definition of a derivative. Because 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 common shares and the Replacement Warrants could not be classified within equity. Therefore the Replacement Warrants were classified as a current liability on Gran Tierra's condensed 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 and retained earnings with a corresponding adjustment to the fair value of derivative instruments recognized on the balance sheet. The fair value of the Replacement Warrants was determined using Level 3 inputs.

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2011	2010	2009
Realized financial derivative gain	$(1,522)	$-	$(87)
Unrealized financial derivative (gain) loss	-	(44)	277
Derivative financial instruments (gain) loss	$(1,522)	$(44)	$190

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 is 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 Solana Petroleum Exploration (Colombia) Ltd. The initial committed borrowing base is $20 million. Amounts drawn down under the facility bear interest at the USD 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 expense. 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, 2011 and 2010, the Company had not drawn down any amounts under this facility.

As part of the acquisition of Petrolifera, Gran Tierra assumed a reserve-backed credit facility with an outstanding balance as at the Acquisition Date of $31.3 million. The outstanding balance was repaid when the Argentine restriction preventing its repayment expired on August 5, 2011.The credit facility bore interest at LIBOR plus 8.25% and was partially secured by the pledge of the shares of Petrolifera's subsidiaries.

Effective February 28, 2007, the Company entered into a credit facility with Standard Bank. As a result of re-negotiations concluded in August 2009, the maximum amount of the credit facility was $200 million with a $7 million borrowing base that could be re-determined semi-annually based on reserve evaluation reports. Amounts drawn down under the facility bore interest at the Eurodollar rate plus 4%. A stand-by fee of 1% per annum was charged on the un-drawn amount of the borrowing base. The facility was secured primarily by the assets of Gran Tierra Colombia and Solana Petroleum Exploration (Colombia) Ltd. This facility expired February 22, 2010.

Interest Expense

Interest expense on the reserve-backed credit facility for the 140 day period from the Acquisition Date to August 5, 2011, the date the facility was repaid, was $1.6 million. This amount is recorded in the Consolidated Statements of Operations as part of G&A expense.

Table of Contents

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 runs from February 1, 2011 to January 30, 2013 and the sublease payment is $4,300 per month plus approximately $4,500 of operating and other expense.

On August 3, 2010, Gran Tierra entered into a contract related to the Peru drilling program with a company for which one of Gran Tierra's directors is a shareholder and director. For the year ended December 31, 2011, $2.8 million was incurred and capitalized under this contract (2010 - $0.8 million) and at December 31, 2011, $nil was included in accounts payable related to this contract (December 31, 2010 - $0.8 million).

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.

15. Subsequent Events

On February 17, 2012, in accordance with the terms of a farmout agreement, the Company gave notice to the other party to the farmout agreement that the Company would not enter into and assume its share of the work obligations of the second exploration period of Block BM-CAL-10. As a result, the farmout agreement has terminated and the Company will not receive any interest in the block. Pursuant to the farmout agreement, the company is obligated to make payment for a certain percentage of the costs relating to Block BM-CAL-10, which relate primarily to the well that was drilled during the term of the farmout agreement. The notice of withdrawal is a trigger for payment of amounts that would otherwise have been due if the farm-out agreement had closed and we had acquired a participating interest. The Company expects to make that payment in the approximate amount of $26 million in March 2012.

Table of Contents

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 assessed 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 Item 7 for a description of Gran Tierra’s reserves estimation process.

PROVED RESERVES NET OF ROYALTIES (1)

	Colombia		Argentina		Brazil		Total	
	Oil (Mbbl)	Gas (MMcf)	Oil (Mbbl)	Gas (MMcf)	Oil (Mbbl)	Gas (MMcf)	Oil (Mbbl)	Gas (MMcf)
Proved Developed and Undeveloped Reserves, December 31, 2008	17,681	1,162	1,557	-	-	-	19,238	1,162
Extensions and Discoveries	2,025	-	-	-	-	-	2,025	-
Purchases of Reserves in Place	(113)	-	-	-	-	-	(113)	-
Production	(4,284)	(49)	(337)	-	-	-	(4,622)	(49)
Revisions of Previous Estimates	5,482	-	71	756	-	-	5,554	756
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	1,113	-	-	-	23,598	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	5,144	3,682	353	-	30,922	18,322
Proved Developed Reserves, December 31, 2009 (2)	20,194	1,113	1,080	756	-	-	21,274	1,869
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

(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.

Table of Contents

B. Capitalized Costs

	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
Capitalized Costs, December 31, 2010	$777,262	$238,119	$(334,858)	$680,523
Colombia	256,596	46,004	(140,093)	162,507
Argentina	95,631	47,630	(44,509)	98,752
Brazil	10,594	52,441	(1,642)	61,392
Capitalized Costs, December 31, 2011	$1,140,083	$384,194	$(521,102)	$1,003,175

C. Costs Incurred

	Oil and Gas			
	Colombia	Argentina	Brazil	Total
Total Costs Incurred before DD&A				
As at December 31, 2008	$ 765,032	$ 35,224	$ -	$ 800,256
Property Acquisition Costs				
Proved	$ -	$ -	$ -	$ -
Unproved	-	-	-	-
Exploration Costs	24,103	246	-	24,349
Development Costs	48,232	4,721	-	52,953
As at 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
As at 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
As at December 31, 2011	$ 1,244,139	$ 217,105	$ 63,034	$ 1,524,277

Table of Contents

D. Results of Operations for Producing Activities

	Colombia	Argentina	Brazil	Total
Year ended December 31, 2009				
Net Sales	$248,834	$13,795	$-	$262,629
Production Costs	(33,091)	(7,537)	-	(40,628)
Exploration Expense	-	-	-	-
DD&A	(126,261)	(8,312)	-	(134,573)
Income Tax (Expense) Recovery	(25,824)	1,470	-	(24,355)
Results of Operations	$63,658	$(585)	$-	$63,073
Year ended December 31, 2010				
Net Sales	$359,302	$13,984	$-	$373,286
Production Costs	(50,431)	(8,808)	-	(59,239)
Exploration Expense	-	-	-	-
DD&A	(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				
Net Sales	$543,999	$48,016	$4,176	$596,191
Production Costs	(58,081)	(27,076)	(1,018)	(86,175)
Exploration Expense	-	-	-	-
DD&A	(140,093)	(44,509)	(1,642)	(186,244)
Income Tax Expense	(114,255)	5,489	-	(108,766)
Results of Operations	$231,570	$(18,080)	$1,516	$215,006

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 2011 twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within that twelve month period was $95.20 (2010 - $71.50; 2009 - $61.04) for Colombia, $54.26 (2010 - $50.18; 2009 – $37.35) for Argentina and $97.07 (2010 - $nil; 2009 – $nil) for Brazil. The calculated weighted average production costs at December 31, 2011 were $10.10 (2010 - $10.48; 2009 - $14.92) for Colombia, $28.50 (2010 - $18.87; 2009 - $20.73) for Argentina and $15.65 (2010 - $nil; 2009 – $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.

Table of Contents

	Colombia	Argentina	Brazil	Total
December 31, 2009				
Future Cash Inflows	$1,117,879	$55,076	-	$1,172,955
Future Production Costs	(312,950)	(29,140)	-	(342,090)
Future Development Costs	(91,867)	(4,923)	-	(96,790)
Future Site Restoration Costs	(1,415)	(566)	-	(1,981)
Future Income Tax	(208,237)	(5,771)	-	(214,008)
Future Net Cash Flows	503,410	14,676	-	518,086
10% Discount Factor	(109,043)	(2,659)	-	(111,702)
Standardized Measure	$394,367	$12,017	$-	$406,384
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 Site Restoration Costs	(8,070)	(385)	-	(8,455)
Future Income Tax	(295,146)	-	-	(295,146)
Future Net Cash Flows	808,090	23,169		831,259
10% Discount Factor	(225,990)	(4,270)	-	(230,260)
Standardized Measure	$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)	(201,154)
Future Site Restoration Costs	(12,420)	(3,063)	(525)	(16,008)
Future Income Tax	(500,700)	(18,207)	(1,215)	(520,121)
Future Net Cash Flows	1,417,074	80,265	15,937	1,513,276
10% Discount Factor	(369,112)	(26,274)	(2,543)	(397,929)
Standardized Measure	$1,047,963	$53,991	$13,394	$1,115,347

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:

	2011	2010	2009
Beginning of Year	$600,999	$406,384	$275,122
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(491,046)	(313,840)	(222,479)
Net Changes in Prices and Production Costs Related to Future Production	446,111	208,649	147,810
Extensions, Discoveries and Improved Recovery, Less Related Costs	206,762	32,194	54,388
Development Costs Incurred during the Period	106,291	107,856	59,024
Revisions of Previous Quantity Estimates	242,761	140,893	149,597
Accretion of Discount	81,422	58,043	38,934
Purchases of Reserves in Place	93,071	-	-
Sales of Reserves in Place	-	-	3,035
Net Change in Income Taxes	(148,529)	(39,180)	(99,047)
Changes in Forecast Development Costs	(22,495)	-	-
End of Year	$1,115,347	$600,999	$406,384

Table of Contents

2) Summarized Quarterly Financial Information

	Revenue and Other Income	Expenses	Income Before Income Taxes	Income Taxes	Net Income (Loss)	Basic Net Income (Loss) Per Share - Basic	Diluted Net Income (Loss) Per Share - Diluted
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
2010							
First Quarter	$93,110	$71,968	$21,142	$11,182	$9,960	$0.04	$0.04
Second Quarter	84,114	53,890	30,224	12,853	17,371	0.07	0.07
Third Quarter	84,569	81,952	2,617	5,894	(3,277)	(0.01)	(0.01)
Fourth Quarter	112,667	72,244	40,423	27,305	13,118	0.05	0.04
	$374,460	$280,054	$94,406	$57,234	$37,172	$0.15	$0.14

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act. Our management, including our Chief Executive Officer and acting Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of December 31, 2011 to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and acting Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting

Gran Tierra’s management is responsible for establishing and maintaining adequate internal control over financial reporting for Gran Tierra, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of Gran Tierra’s management, including our principal executive and principal financial officers, Gran Tierra conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the “COSO Framework”). Based on this evaluation under the COSO Framework, management concluded that its internal control over financial reporting was effective as of December 31, 2011.

The effectiveness of Gran Tierra’s internal control over financial reporting as of December 31, 2011 has been audited by Deloitte & Touche LLP, independent registered chartered accountants.

Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2011, there was no change in Gran Tierra’s internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, Gran Tierra’s internal control over financial reporting.

Table of Contents

Report of Independent Registered Chartered Accountants

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

We have audited the internal control over financial reporting of Gran Tierra Energy Inc. and subsidiaries (the “Company”) as of December 31, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management’s Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company and our report dated February 27, 2012 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 27, 2012

Table of Contents

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required regarding our directors is incorporated herein by reference from the information contained in the section entitled “Proposal 1 - Election of Directors” in our definitive Proxy Statement for the 2012 Annual Meeting of Stockholders (our “Proxy Statement”), a copy of which will be filed with the Securities and Exchange Commission within 120 days after December 31, 2011. For information with respect to our executive officers, see “Executive Officers of the Registrant” at the end of Part I of this report, following Item 3.

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

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

Adoption of Code of Ethics

Gran Tierra has adopted a Code of Business Conduct and Ethics (the “Code”) applicable to all of its Board members, employees and executive officers, including its Chief Executive Officer (Principal Executive Officer), and acting Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer). Gran Tierra has made the Code available on its website at http://www.grantierra.com/corporate-responsibility.html.

Gran Tierra intends to satisfy the public disclosure requirements regarding (1) any amendments to the Code, or (2) any waivers under the Code given to Gran Tierra’s Principal Executive Officer, Principal Financial Officer and Principal Accounting Officer by posting such information on its website at http://www.grantierra.com/corporate-responsibility.html. There were no amendments to the Code or waivers granted thereunder relating to the Principal Executive Officer, Principal Financial Officer or Principal Accounting Officer during 2011.

Item 11. Executive Compensation

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

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

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

The following table provides certain information with respect to securities authorised for issuance under Gran Tierra's equity compensation plans in effect as of the end of December 31, 2011:

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of options	Weighted average exercise price of outstanding options		Number of securities remaining available for future issuance
Equity compensation plans approved by security holders	12,864,002	$	4.90	4,251,304
Equity compensation plans not approved by security holders	-		-	-
Total	12,864,002	$	4.90	4,251,304

The only equity compensation plan approved by our stockholders is our 2007 Equity Incentive Plan, which is an amendment and restatement of our 2005 Equity Plan.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required regarding related transactions is incorporated herein by reference from the information contained in the section entitled "Certain Relationships and Related Transactions" and, with respect to director independence, the section entitled "Proposal 1 - Election of Directors", in our Proxy Statement.

Item 14. Principal Accounting Fees and Services

The information required is incorporated herein by reference from the information contained in the sections entitled "Principal Accountant Fees and Services" and "Pre-Approval Policies and Procedures" in the proposal entitled "Ratification of Selection of Independent Auditors" in our Proxy Statement.

Table of Contents

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report on Form 10-K:

(1) Financial Statements

The following documents are included as Part II, Item 8. of this Annual Report on Form 10-K:

	Page
Report of Independent Registered Chartered Accountants	60
Consolidated Statements of Operations and Retained Earnings	61
Consolidated Balance Sheets	62
Consolidated Statements of Cash Flow	64
Consolidated Statements of Shareholders’ Equity	66
Notes to the Consolidated Financial Statements	67
Supplementary Data (Unaudited)	82

(2) Financial Statement Schedules

None.

(3) Exhibits

See the Exhibit Index which follows the signature page of this Annual Report on Form 10-K, which is incorporated herein by reference.

SIGNATURES

Pursuant to the requirements of section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

GRAN TIERRA ENERGY INC.

Date:	February 27, 2012	By:	/s/ Dana Coffield Dana Coffield Chief Executive Officer and President (Principal Executive Officer)
Date:	February 27, 2012	By:	/s/ James Rozon James Rozon Acting Chief Financial Officer (Principal Financial and Accounting

Officer)

Table of Contents

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Dana Coffield and James Rozon, and each of them, as his true and lawful attorneys-in-fact and agents, with full power of substitution and resubstitution, for him and in his name, place and stead, in any and all capacities, to sign any and all amendments (including post-effective amendments) to this Annual Report on Form 10-K, and to file the same, with all exhibits thereto, and other documents in connection therewith, with the Securities and Exchange Commission, granting unto said attorneys-in-fact and agents, and each of them, full power and authority to do and perform each and every act and thing requisite and necessary to be done in connection therewith, as fully to all intents and purposes as he might or could do in person, hereby ratifying and confirming all that said attorneys-in-fact and agents, or any of them, or their or his substitute or substitutes, may lawfully do or cause to be done by virtue hereof.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated:

Name	Title	Date
/s/ Dana Coffield Dana Coffield	Chief Executive Officer and President (Principal Executive Officer)	February 27, 2012
/s/ James Rozon James Rozon	Acting Chief Financial Officer (Principal Financial and Accounting Officer)	February 27, 2012
/s/ Jeffrey Scott Jeffrey Scott	Chairman of the Board, Director	February 27, 2012
/s/ Verne Johnson Verne Johnson	Director	February 27, 2012
/s/ Nicholas G. Kirton Nicholas G. Kirton	Director	February 27, 2012
/s/ J. Scott Price J. Scott Price	Director	February 27, 2012
/s/ Ray Antony Ray Antony	Director	February 27, 2012
/s/ Gerry Macey Gerry Macey	Director	February 27, 2012

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description	Reference
2.1	Arrangement Agreement, dated as of July 28, 2008, by and among Gran Tierra Energy Inc., Solana Resources Limited and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on August 1, 2008 (File No. 001-34018).
2.2	Amendment No. 2 to Arrangement Agreement, which includes the Plan of Arrangement, including appendices.	Incorporated by reference to Exhibit 2.2 to the Registration Statement on Form S-3 (Reg. No. 333-153376), filed with the SEC on October 10, 2008 (File No. 001-34018).
2.3	Arrangement Agreement, dated January 17, 2011, by and between Gran Tierra Energy Inc. and Petrolifera Petroleum Limited.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (File No. 001-34018).
3.1	Amended and Restated Articles of Incorporation.	Incorporated by reference to Exhibit 3.1 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
3.2	Fifth Amended and Restated Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on September 22, 2008 (File No. (File No. 001-34018).
4.1	Reference is made to Exhibits 3.1 and 3.2.	
4.2	Form of Warrant issued to institutional and retail investors in connection with the private offering in June 2006.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 21, 2006 (File No. 333-111656).
4.3	Details of the Goldstrike Special Voting Share.	Incorporated by reference to Exhibit 10.14 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005 and filed with the Securities and Exchange on April 21, 2006 (File No. 333-111656).
4.4	Goldstrike Exchangeable Share Provisions.	Incorporated by reference to Exhibit 10.15 to the Annual Report on Form 10-KSB/A for the period ended December 31, 2005 and filed with the Securities and Exchange on April 21, 2006 (File No. 333-111656).
4.5	Provisions Attaching to the GTE–Solana Exchangeable Shares.	Incorporated by reference to Annex E to the Proxy Statement on Schedule 14A filed with the Securities and Exchange Commission on October 14, 2008 (File

		No. 001-34018).
4.6	Reference is made to Exhibits 10.1 through 10.11 below.	
4.7	Supplemental Warrant Indenture, dated as of March 18, 2011, among Gran Tierra Energy Inc., Petrolifera Petroleum Limited, and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 4.6 to the Quarterly Report on Form 10-Q (SEC File No. 001-34018), filed with the SEC on May 10, 2011.
10.1	Form of Registration Rights Agreement by and among Goldstrike Inc. and the purchasers named therein.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on December 19, 2005 (File No. 333-111656).
10.2	Form of Registration Rights Agreement by and among Goldstrike Inc. and the purchasers named therein.	Incorporated by reference to Exhibit 10.32 to Form SB-2, as amended, filed with the Securities and Exchange Commission on December 7, 2006 (File No. 333-111656).
10.3	Form of Registration Rights Agreement by and among Gran Tierra Energy, Inc. f/k/a Goldstrike, Inc. and the purchasers named therein.	Incorporated by reference to Exhibit 10.34 to Form SB-2, as amended, filed with the Securities and Exchange Commission on December 7, 2006 (File No. 333-111656).
10.4	Form of Registration Rights Agreement, dated as of June 20, 2006, by and among Gran Tierra Energy Inc. and institutional investors purchasing units of Gran Tierra Energy Inc. securities in a private offering.	Incorporated by reference to Exhibit 10.23 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 21, 2006 (File No. 333-111656).
10.5	Form of Registration Rights Agreement, dated as of June 20, 2006, by and among Gran Tierra Energy Inc. and retail investors purchasing units of Gran Tierra Energy Inc. securities in a private offering.	Incorporated by reference to Exhibit 10.24 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 21, 2006 (File No. 333-111656).
10.6	Registration Rights Agreement, dated as of June 20, 2006, by and between Gran Tierra Energy Inc. and CD Investment Partners, Ltd.	Incorporated by reference to Exhibit 10.25 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 21, 2006 (File No. 333-111656).

10.7	Registration Rights Agreement, dated as of June 20, 2006, by and between Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.27 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on June 21, 2006 (File No. 333-111656).
10.8	Form of Registration Rights Agreement, dated as of June 30, 2006, by and among Gran Tierra Energy Inc. and the investors in the June 30, 2006 closing of the Offering.	Incorporated by reference to Exhibit 10.30 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on July 5, 2006 (File No. 333-111656).
10.9	Voting Exchange and Support Agreement by and between Goldstrike, Inc., 1203647 Alberta Inc., Gran Tierra Goldstrike Inc. and Olympia Trust Company dated as of November 10, 2005.	Incorporated by reference to Exhibit 10.3 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (File No. 333-111656).
10.10	Voting and Exchange Trust Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Exchangeco Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 17, 2008 (File No. 001-34018).
10.11	Support Agreement, dated as of November 14, 2008, between Gran Tierra Energy Inc., Gran Tierra Callco ULC and Gran Tierra Exchangeco Inc.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on November 17, 2008 (File No. 001-34018).
10.12	Amended and Restated 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (File No. 001-34018).
10.13	Form of Option Agreement under the Company's 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 99.1 to the current report on Form 8-K filed with the Securities and Exchange Commission on December 21, 2007 (File No. 000-52594).
10.14	Form of Grant Notice under the Company's 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 99.2 to the current report on Form 8-K filed with the Securities and Exchange Commission on December 21, 2007 (File No. 000-52594).
10.15	Form of Exercise Notice under the Company's 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 99.3 to the current report on Form 8-K filed with the Securities and Exchange Commission on December 21, 2007 (File No. 000-52594).
10.16	Form of Indemnity Agreement. *	Incorporated by reference to Exhibit 99.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on April 2, 2008 (File No. 000-52594).

10.17	2005 Equity Incentive Plan. *	Incorporated by reference to Exhibit 10.11 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 10, 2005 (File No. 333-111656).
10.18	2009 Executive Officer Cash Bonus Compensation and 2010 Cash Compensation Arrangements*	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 18, 2010 (File No. 001-34018).
10.19	2010 Executive Officer Cash Bonus Compensation and 2011 Cash Compensation Arrangements *	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on February 9, 2011 with respect to the 2010 Executive Officer Cash Bonus Compensation, and incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 with respect to 2011 Cash Compensation Arrangements (in each case, File No. 001-34018).
10.20	Employment Agreement, dated November 4, 2008, between Gran Tierra Energy Inc. and Dana Coffield.*	Incorporated by reference to Exhibit 10.57 to the Annual Report on Form 10-K, filed with the SEC on February 27, 2009 (File No. 001-34018).
10.21	Employment Agreement, dated June 17, 2008, between Gran Tierra Energy Inc. and Martin Eden. *	Incorporated by reference to Exhibit 10.58 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (File No. 001-34018).
10.22	Employment Agreement, dated June 17, 2008, between Gran Tierra Energy Inc. and Rafael Orunesu.*	Incorporated by reference to Exhibit 10.61 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (File No. 001-34018).
10.23	Employment Agreement, dated November 23, 2009, between Gran Tierra Energy Inc. and Julian Garcia *	Incorporated by reference to Exhibit 10.23 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (File No. 001-34018).
10.24	Offer Letter between Gran Tierra Energy Inc. and Shane P. O'Leary dated January 26, 2009 *	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on February 4, 2009 (File No. 001-34018).
10.25	Employment Agreement between Gran Tierra Energy Inc. and Shane P. O'Leary dated as of January 26, 2009. *	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on February 4, 2009 (File No. 001-34018).
10.26	Employment Agreement, dated July 1, 2009, between Gran Tierra Energy Inc. and Julio César Moreira.*	Incorporated by reference to Exhibit 10.62 to the Annual Report on Form 10-K for the period ended December 31, 2009 and filed with the Securities and Exchange on February 26, 2010 (File No. 001-34018).

Table of Contents

10.27	Colombian Participation Agreement, dated as of June 22, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.55 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (File No. 333-111656).
10.28	Amendment No. 1 to Colombian Participation Agreement, dated as of November 1, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.56 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (File No. 001-34018).
10.29	Amendment No. 2 to Colombian Participation Agreement, dated as of July 3, 2008, between Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q/A, filed with the SEC on November 19, 2008 (File No. 001-34018).
10.30	Amendment No. 3 to Participation Agreement, dated as of December 31, 2008, by and among Gran Tierra Energy Colombia, Ltd., Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 7, 2009 (File No. 001-34018).
10.31	Form of Voting Support Agreement Respecting the Arrangement Involving Petrolifera Petroleum Limited and Gran Tierra Energy Inc. (Petrolifera Directors and Officers)	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (File No. 001-34018).
10.32	Form of Voting Support Agreement Respecting the Arrangement Involving Petrolifera Petroleum Limited and Gran Tierra Energy Inc. (Petrolifera largest stockholder)	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on January 21, 2011 (File No. 001-34018).
10.33	Credit Agreement, dated as of July 30, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., the Lenders party thereto, and BNP Paribas.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on August 5, 2010 (File No. 001-34018).
10.34	First Amendment to Credit Agreement, dated as of August 30, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 5, 2010 (File No. 001-34018).
10.35	Second Amendment to Credit Agreement, dated as of November 5, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders	Incorporated by reference to Exhibit 10.46 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (File No. 001-34018).
10.36	Third Amendment to Credit Agreement, dated as of January 20, 2011, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders	Incorporated by reference to Exhibit 10.47 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (File No. 001-34018).
10.37		

	Agreement between Gran Tierra Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 15, 2010 (File No. 001-34018).
10.38	Amendment No. 1, executed November 8, 2010, to Agreement between Gran Tierra Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed with the Securities and Exchange Commission on November 15, 2010 (File No. 001-34018).
10.39	Addendum, entered into between Gran Tierra Colombia Ltd. and Ecopetrol S.A. on December 30, 2010, amending the Agreement between those parties dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block	Incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (File No. 001-34018).
10.40	Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009, and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block	Incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (File No. 001-34018).
10.41	Amendment No. 1, executed November 8, 2010, to Agreement between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block	Incorporated by reference to Exhibit 10.52 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (File No. 001-34018).
10.42	Addendum, entered into between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A. on December 30, 2010, amending the Agreement between those parties dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.53 to the Annual Report on Form 10-K, filed with the SEC on February 25, 2011 (File No. 001-34018).
10.43	Addendum No. 2, entered into between Gran Tierra Colombia Ltd. and Ecopetrol S.A. on December 30, 2010, amending the Agreement between those parties dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (File No. 001-34018).

Table of Contents

10.44	Addendum No. 2, entered into between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A. on June 30, 2011, amending the Agreement between those parties dated December 17, 2009 and accepted December 18, 2009, with respect to the sale of crude oil from the Chaza Block.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (File No. 001-34018).
10.45	Contract, dated July 27, 2011, between Gran Tierra Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (File No. 001-34018).
10.46	Contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 9, 2011 (File No. 001-34018).
10.47	Executive Employment Agreement dated July 30, 2009 between Gran Tierra Energy Inc. and Duncan Nightingale *	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (File No. 001-34018).
10.48	Expatriate Assignment Agreement to Gran Tierra Colombia Ltd., dated December 7, 2010 between Gran Tierra Energy Inc. and Duncan Nightingale *	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (File No. 001-34018).
10.49	Employment Contract dated January 31, 2011 between Gran Tierra Colombia Ltd. and Duncan Nightingale *	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (File No. 001-34018).
10.50	Amendment to Expatriate Assignment Agreement, dated October 13, 2011 between Gran Tierra Energy Inc. and Duncan Nightingale *	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on November 8, 2011 (File No. 001-34018).
10.51	Consulting Services Agreement, between David Hardy and Gran Tierra Energy Inc.*	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 (File No. 001-34018).
10.52	Executive Employment Agreement, dated January 20, 2010, between Gran Tierra Energy Inc. and David Hardy.*	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 10, 2011 (File No. 001-34018).
10.53		Filed herewith.

	Notice of termination of contract dated December 2, 2011 regarding the contract dated July 27, 2011, between Gran Tierra Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	
10.54	Notice of termination of contract dated December 2, 2011 regarding the contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.
10.55	Amendment dated December 22, 2011 to notice of termination of contract dated December 2, 2011 regarding the contract dated July 27, 2011, between Gran Tierra Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.
10.56	Amendment dated December 22, 2011 to notice of termination of contract dated December 2, 2011 regarding the contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.
10.57	Employment Agreement between Gran Tierra Energy Inc. and James Rozon dated as of September 10, 2007. *	Filed herewith.
10.58	Amendment dated January 30, 2012 to contract, dated July 27, 2011, between Gran Tierra Colombia Ltd and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.
10.59	Amendment dated January 30, 2012 to contract, dated July 27, 2011, between Solana Petroleum Exploration Colombia Ltd. and Ecopetrol S.A., for the Purchase and Sale of Crude Oil from the Chaza, Santana and Guayuyaco Blocks.	Filed herewith.

Table of Contents

21.1	List of subsidiaries.	Filed herewith.
23.1	Consent of Deloitte & Touche LLP	Filed herewith.
23.2	Consent of GLJ Petroleum Consultants	Filed herewith.
24.1	Power of Attorney.	See signature page.
31.1	Certification of Principal Executive Officer	Filed herewith.
31.2	Certification of Principal Financial Officer	Filed herewith.
32.1	Certification of Principal Executive and Financial Officers	Filed herewith.
99.1	Gran Tierra Energy Inc. Reserves Assessment and Evaluation of Colombian, Argentine and Brazilian Oil and Gas Properties Corporate Summary, effective December 31, 2011	Filed herewith.

101.INS# XBRL Instance Document
101.SCH# XBRL Taxonomy Extension Schema Document
101.CAL# XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF XBRL Taxonomy Extension Definition Linkbase Document
101.LAB# XBRL Taxonomy Extension Label Linkbase Document
101.PRE# XBRL Taxonomy Extension Presentation Linkbase Document

XBRL information is furnished and not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.

* Management contract or compensatory plan or arrangement.