GRAN TIERRA ENERGY, INC.
Form 10-K
February 25, 2011

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, 2010

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 $1,197,806,292 (including shares issuable upon exercise of exchangeable shares). Aggregate market value excludes an aggregate of 1,101,633 shares of common stock and 11,125,525 shares issuable upon exercise of exchangeable shares held by officers and directors and by each person known by the registrant to own 10% or more of the outstanding common stock 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 18, 2011, the following numbers of shares of the registrant's capital stock were outstanding: 240,857,632 shares of the registrant's Common Stock, $0.001 par value; one share of Special A Voting Stock, $0.001 par value, representing 7,811,112 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 9,539,042 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 2011 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after the fiscal year to which this Report relates.

GRAN TIERRA ENERGY INC.

ANNUAL REPORT ON FORM 10-K

Year ended December 31, 2010

TABLE OF CONTENTS

PART I

This Annual Report on Form 10-K, particularly in Item 1. “Business”, Item 2. “Properties”, 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 simil or 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.

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. A detailed description of our properties can be found under Item 2 “Properties”. All dollar ($) amounts referred to in this Form 10-K are United States (U.S.) dollars, unless otherwise indicated.

In 2010, our geographic focus was on South America. We focused on development of producing fields and generation of exploration prospects in Colombia, including the award of three blocks in the 2010 Colombia Bid Round, and acquisition of a working interest in an additional block. In Argentina, we maintained existing production and commenced work on a natural gas project which was suspended in February, 2011 and will be abandoned. We continue to review alternatives to evaluate to field development. In Peru, we received Environmental Impact Assessment approvals, commenced seismic and preparation for drilling operations and further expanded our exploration portfolio through acquisition of working interests in four additional blocks. In Brazil, we entered into our initial exploration and development transaction by acquiring a 70% working interest in each of in four blocks in the on-shore Reconcavo Basin. The blocks awarded in Colombia and acquired in Peru and Brazil are still subject to various approvals. On January 17, 2011, we entered into an agreement to acquire all the issued and outstanding shares and warrants of Petrolifera Petroleum Ltd. (“Petrolifera”) pursuant to a Plan of Arrangement (the “Arrangement”), subject to Petrolifera shareholder, regulatory, stock exchange, and court approvals. Petrolifera is a Canadian based international oil and gas company listed on the Toronto Stock Exchange and owns working interests in 11 exploration and production blocks - three located in Colombia, three in Peru and five in Argentina. The Arrangement is expected to close in March 2011. See “Subsequent Events” in Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” for further details.

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. 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. Room 1580, 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. The SEC's website address is www.SEC.gov.

The Oil and Gas Business

In the discussion that follows, and in Item 2 "Properties", 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, and 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 and sales are reported net after deduction of royalties. 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.

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.

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

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. Computers 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 any range of a wide 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 not drilled in a known area or “development type” if drilled in a known area.

Workover is a term used to describe remedial operations on a previously completed well to clean, repair and/or maintain the well for the 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.

BOPD is a commonly used abbreviation in the oil and gas business which means barrels of oil per day.

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 of this Form 10-K.

Development of Our Business

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 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. The blocks awarded in Colombia and acquired in Peru and Brazil are still subject to various governmental approvals. As a result of these acquisitions, including the acquisitions subject to various government approvals, our acreage as of December 31, 2010 includes:

- 2,637,916 gross acres in Colombia (2,289,169 net) covering sixteen exploration and production contracts, five of which are producing and all but one of which are operated by Gran Tierra (includes 1,470,645 gross and net acres subject to government approval);

- 1,628,473 gross acres (1,294,107 net) in Argentina covering seven exploration and production contracts, four of which are producing, and all but one of which are operated by Gran Tierra;

- 11,431,141 gross acres (5,544,820 net) in Peru covering six exploration and exploitation licenses, all of which are frontier exploration areas and three of which are operated by Gran Tierra (includes 7,995,101 gross acres and 2,108,780 net acres subject to government approval); and

- 27,075 gross acres (18,953 net) in Brazil covering four exploration blocks to be operated by Gran Tierra (all acreage subject to government approval).

Colombia

In Colombia in 2010, on the Chaza Block, we continued the development of our Costayaco field, completing Costayaco-11 in June 2010 as a producing well and commenced drilling of Costayaco-12 and Costayaco-13 in December 2010.

In early January 2010, we plugged and abandoned an exploration well, Dantayaco-1. We also drilled an exploration well on the Chaza Block in May (Moqueta-1), which resulted in an oil discovery. The Moqueta-2 delineation well was spud in July, the Moqueta-3 delineation well was spud in September and an additional delineation well, Moqueta-4, was spud in late December with testing expected to be complete in March 2011. The design, permitting and construction of a pipeline to connect Moqueta to existing infrastructure is continuing and first production from Moqueta is expected early in the second quarter of 2011. A third exploration well in the Chaza Block was spud in November (Pacayaco-1) and was suspended until the acquisition of new 3D seismic was completed and interpreted. The acquisition and interpretation is now complete and we plan to drill either a new well or a sidetrack of the existing well late in the second quarter of 2011. On our Rio Magdalena Block, we drilled the Popa-3 well, which has been suspended pending evaluation. In our non-operated Garibay Block, we drilled one exploration well (Jilguero-1), which resulted in an oil discovery. On our Piedemonte Sur Block, preparations for an exploration well, Taruka-1, began in December 2010. The well was spud in January 2011 and was plugged and abandoned in February 2011.

We were awarded 3 blocks in the Colombia Bid Round 10, Cauca-6, Cauca-7, and Putumayo-10, in June 2010. These are pending Agencia Nacional de Hidrocarburos or National Hydrocarbons Agency ("ANH") approval and represent 1,470,646 gross acres (1,470,646 net acres). We also acquired a 55% interest in the Putumayo -1 Block through a farm-in.

Details of our 2011 plans are contained in Item 2 "Properties".

Argentina

In Argentina in July 2010, we began re-entry and sidetrack operations on the Valle Morado GTE.St.VMor-2001 gas well. In February 2011, these operations were suspended and the wellbore will be abandoned due to a number of operational challenges encountered. We continue to review alternatives associated with the field development. Also in 2010, several successful workovers were completed on wells in other blocks in order to maintain production levels. Gran Tierra filed an application for relinquishment related to the Ipaguazu Block in 2010 and is awaiting government approval.

Details of our 2011 plans are contained in Item 2 "Properties".

Peru

In Peru in 2010, we received Environment Impact Assessment ("EIA") approvals for seismic and drilling operations on Block 122 and Block 128. We completed our seismic acquisition program in Block 128 and partially completed the seismic program in Block 122. Completion of the remaining seismic program in Block 122 is expected in the first quarter of 2011 and an exploration well is planned for the third quarter of 2011. Pad construction for the first exploration well in Block 128 began in December and the well was spud in February 2011. Also in February 2011, we relinquished 20% of Block 128.

In September 2010, we entered into an agreement to acquire a 20% working interest in Block 123, Block 124, and Block 129, subject to government approval. Burlington Resources Peru Ltd. (a wholly owned subsidiary of ConocoPhillips) is the operator of these three blocks. A 747 kilometer 2D seismic program was shot in these three blocks in 2010.

In December 2010, we entered into an agreement to acquire operatorship and a 60% working interest in Block 95, subject to government approval.

Details of our 2011 plans are contained in Item 2 “Properties”.

Brazil

In August 2010, we entered into an agreement to acquire operatorship and a 70% working interest in four onshore blocks in the Reconcavo Basin (Blocks 129, 142, 155 and 224), subject to government approval . In 2010, a 93 kilometer 2D seismic program was completed on three of these blocks.

Details of our 2011 plans are contained in Item 2 “Properties”.

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;

- 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.

Markets and Customers

Ecopetrol S.A. (“Ecopetrol”), the Colombian majority state owned oil company, is the purchaser of most of the crude owned by our Colombian branches, Gran Tierra Energy Colombia Ltd. (“Gran Tierra Colombia”) and Solana Petroleum Exploration (Colombia) Ltd. (“Solana Colombia”). 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: (i) from Santana Station to Ecopetrol’s storage terminal at Orito, a distance of approximately 46 kilometers, and (ii) from Costayaco to Ecopetrol’s storage terminal at Neiva (Dina Station), approximately 350 kilometers north of the Chaza Block. Crude oil prices for sales to Ecopetrol are defined by multi-year agreements with Ecopetrol based on West Texas Intermediate NYMEX ("WTI/NYMEX") price less adjustments for quality and transportation. These agreements are subject to renegotiation periodically and generally contain mutual termination provisions with 90 days notice. For commercial purposes, on November 8, 2010, we agreed to amend our Chaza Block Crude Oil Sales Agreement between Gran Tierra Colombia and Ecopetrol whereby Ecopetrol was required to purchase 90% (previously 100%) of the volume of crude oil production produced by Gran Tierra Colombia in the Chaza Block (exclusive of the volume of oil owned by ANH corresponding to royalties). Subsequently, on December 30, 2010, this agreement was further amended to require Gran Tierra Colombia to sell 100% of its Chaza Block crude oil to Ecopetrol (exclusive of the volume of oil owned by ANH corresponding to royalties). Additionally, on December 30, 2010, both agreements (Gran Tierra Colombia and Solana Colombia with Ecopetrol), previously expiring December 31, 2010 were extended to June 30, 2011, but with a clause that allows both companies to sell to third parties any crude oil not accepted by Ecopetrol.

In October 2010, Gran Tierra Colombia entered into a one year contract to sell up to 2,000 barrels of oil per day of Chaza Block crude oil production to Petrobras International Braspetro B.V. (“Petrobras International”). Sales of Chaza Block crude oil production to Petrobras International commenced in December 2010 with volumes trucked to their Rio Ceibas Station (near Neiva). Crude oil prices for sales to Petrobras International are based on WTI price less adjustments for quality, transportation, marketing and handling. This contract may be extended an additional year if agreed to by both parties and contains mutual termination provisions with 90 days notice. In December 2010, a similar contract was executed between Solana Colombia and Petrobras International.

Our oil in Colombia is good quality light oil. In 2010, we received 100% of our revenue in U.S. dollars. Sales to Ecopetrol accounted for 96% of Gran Tierra’s revenues in 2010, 94% of our revenues in 2009 and 89% of our revenues in 2008.

Gas produced on the Magangue Block in the Lower Magdalena Basin, (Guepaje – 1 Well) is sold to Surtigas. The gas price is determined by contract with the customer. Sales to Surtigas accounted for less than 1% of our revenues in 2010, 2009 and 2008.

We market our own share of production in Argentina. The purchaser of our oil in Argentina is Refineria del Norte S.A. (“Refinor S.A.”) . In Argentina, export prices for crude 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 crude oil prices are agreed on a spot basis with Refinor S.A., 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. Our contract with Refinor S.A. expired January 1, 2008; however, we are continuing sales of our oil under monthly agreements with Refinor S.A. Sales to Refinor S.A. accounted for 4% of our revenues in 2010, 5.8% of our revenues in 2009 and 9% of our revenues in 2008.

Gran Tierra entered Brazil in 2010 by acquiring a 70% working interest in four exploration blocks in the Reconcavo Basin. One of these blocks, Block REC-155 has current production of approximately 500 barrels of oil per day gross. Gran Tierra will be the operator of these blocks once government approval for the acquisition of this working interest is obtained. Petróleo Brasileiro S.A (“Petrobras”) is the purchaser of most of the crude oil produced from this block. Crude oil is trucked 26 miles to the Petrobras Carmo Oil Treatment Station. Crude oil prices for sales to Petrobras are at spot market prices, based on Brent DTD (“Brent”), until the producing well completes long term testing. At that time a crude oil sales contract can be entered into by both parties.

There were no sales in any other country other than Colombia and Argentina in 2010, 2009 and 2008.

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 ” 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.

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 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. Corporate assets include assets held by our corporate head office in Calgary, Alberta, Canada, and assets held in Peru and 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 may 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 crude 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.

Gran Tierra operates in Colombia through two branches – Gran Tierra Colombia and Solana Colombia. Both are qualified as operators of oil and gas properties by ANH.

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

Argentina

The Hydrocarbons Law 17.319, enacted in June 1967, established the basic legal framework for the current 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 new legal framework replaces article one of the Hydrocarbons Law 17.319 and provides for the provinces to assume complete ownership, authority and administration of the crude 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, exploitation and transportation concessions.

On June 3, 2002, the Argentine government issued a resolution authorizing the Energy Secretariat to limit the amount of crude 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 crude 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 Argentine government 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, new 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 received credit under the Petroleum Plus program related to our production for the fourth quarter of 2008. Gran Tierra did not qualify for credit for oil production in 2009. In April 2010, the Federal Secretariat of Energy approved Gran Tierra’s Gas Plus project for the development of the Valle Morado field.

In October 2010, the Argentine Gas Authority (“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. This regulation is being challenged by gas producers on the grounds that it illegally interferes in their gas marketing activities.

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. 26221enacted 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, requires that investments in the petroleum sector be undertaken solely by private investors (either national or foreign), 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 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 this 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. Peru’s laws also allow 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 Peru’s corporate law and appoint representatives in accordance with the Organic Hydrocarbon Law who will interact with Perupetro.

Gran Tierra has been qualified by Perupetro with respect to our current contracts for Block 122 and Block 128 and is awaiting approval from the Government of Peru for the recently acquired interests in Block 123, Block 124, Block 129 and Block 95. However, Perupetro reviews the qualification for each specific contract to be signed by a company. Additionally, the qualification for foreign companies is granted in favor of the home office or corporation, which is jointly and severally liable at all times for the technical, legal, economic and financial capacity of its Peruvian subsidiary or branch.

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 natural emergencies where the law stipulates such manner.

Brazil

In Brazil, law No. 2004 enacted in 1953 instituted the state monopoly of the petroleum industry and created Petrobras, a corporation using public and private funds under control of the Federal Union of Brazil ("Federal Union"), to be the exclusive operator of exploration and production concessions in Brazil.

Amendment No. 9 to the Federal Constitution, issued on November 9, 1995, authorized the Federal Union to execute contracts with state and private companies for the exploration and production of oil and natural gas, as well as for the refining, transportation, import and export of oil, natural gas and its by-products, discontinuing Petrobras' exclusive right to operate exploration and production concessions in Brazil.

Oil and natural gas located in Brazil, whether onshore or offshore, are the property of the Federal Union. 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. Part of the revenues from the exploitation of the hydrocarbon resources collected by the Federal Union is passed on to States and Municipalities.

The new institutional and regulatory model is governed by Law No. 9478, the Petroleum Law, which controls the granting of concessions and authorization for carrying out exploration and production activities to Brazilian companies, i.e., those created in accordance with Brazilian laws, with head offices and management located within the national territory.

In accordance with the Petroleum Law, the acquisition of oil and natural gas property and oil and gas operations by state and private companies are subject to legal, technical and economic standards and regulations issued by the National Petroleum Agency (“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.

ANP has authority for the implementation of the national oil and natural gas policy. 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.

The granting of concession contracts is preceded by a public bid procedure, regulated by ANP. Any company evidencing technical, financial and legal standards under the applicable regulations may qualify and apply for particular blocks made available for concession contracts at each licensing round. 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 the 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/transferred to other Brazilian companies that comply with the technical, financial and legal requirements established by ANP.

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.

Gran Tierra Energy Brasil Ltda (“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 crude 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 2011, we plan to spend approximately $5.3 million in Colombia on capital programs related to environmental matters, including facilities upgrades, studies, assessments and remediation. We plan to spend approximately $0.4 million in Argentina on capital programs related to environmental matters, including environmental studies and fire system upgrades. In Peru, capital costs for environmental projects will be about $2.4 million. In Brazil, we plan to spend approximately $0.1 million on capital costs for environmental projects.

In 2010, we experienced a limited number of environmental incidents and enacted many environmental initiatives as follows:

- In Colombia, we dealt with several incidents:

- In the first quarter of 2010, a faulty truck valve caused a spill of 3.5 barrels on one of the roads in Putumayo and a ruptured injection line at Linda Battery caused the release of 20 barrels contaminating an area of approximately 40 square meters. During the second quarter another truck with a faulty valve caused the contamination of 600 meters of road releasing 35 gallons of oil. A transportation expert was hired to assess the trucking operation and develop a preventive plan. In the third quarter of 2010 an operator failed to follow procedures and released a tanker prior to daylight hours and without the proper checks. Subsequently the tanker was involved in a rollover incident causing the spill of 160 barrels of oil. The total cost of the accident was estimated at $0.5 million. In each of these incidents Gran Tierra completed a full clean-up.

- A number of small incidents on our blocks occurred during the year, each of which causing 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 were lost as a result of these incidents.

- In Argentina, EIA's were conducted for the Santa Victoria seismic and Valle Morado drilling programs.

- In Peru, we received EIA approvals for seismic and drilling operations on Block 122 and Block 128.

We will continue to strive to be in compliance with all environmental and pollution control laws and regulations in Colombia, Argentina and Peru and also now in Brazil as we commence our initial operations. 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 are in the process of implementing a company wide web based reporting system which will allow 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 crude oil. We implemented a regular quarterly comprehensive reporting system in 2009, and continue with a schedule of internal audit and routine checking of practices and procedures. Emergency Response exercises were conducted in Calgary, Argentina, Colombia and Peru.

Community Relations

In 2010, 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 2010 are as follows:

Colombia

In 2010, we significantly increased our community relations initiatives and investment, most significantly in the Costayaco field. Below is a description of Gran Tierra's $1.2 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.

- 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, and construction of a local fire station.

Argentina

In Argentina we invested approximately $270,000 in the following projects:

- Provided and distributed education materials to over 19 schools in our operated areas.
- 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.
- 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 Peru, we invested $585,200 in the following projects:

- Negotiated a compensation program with communities for use of their lands.
- Provided consultation and education sessions with various communities located on our two 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

We plan to spend approximately $140,000 for consulting services related to environmental initiatives on our new block.

Employees

At December 31, 2010, we had 307 full-time employees — 29 located in the Calgary corporate office, 210 in Colombia (103 staff in Bogota and 107 field personnel), 49 in Argentina (26 office staff in Buenos Aires and 23 field personnel), 15 in Peru (both field and office staff) and 4 in Brazil, all office staff. None of our employees are represented by labor unions, and we consider our employee relations to be good.

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 in Colombia and Argentina is limited to one basin per country. 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. Once delivered to Ecopetrol, all of our current oil production in Colombia is transported by an export pipeline which provides the only access to markets for our oil. 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 the company and the public.

As the majority of current oil production in Argentina is trucked to a local refinery, sales of oil 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.

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, Llanos, Middle Magdalena and Lower Magdalena basins. The Putumayo and Catatumbo regions have been prone to guerilla activity. In 1989, our predecessor company’s facilities in one field were attacked by guerillas and operations were briefly disrupted. Again on 16 October 2010, two of our sites in the Putumayo/Cauca were attacked by FARC guerillas 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 guerillas, which temporarily reduced our deliveries to Ecopetrol during the affected periods.

Continuing attempts by the Colombian Government to reduce or prevent guerilla activity may not be successful and guerilla activity may disrupt our operations in the future. There can also be no assurance that we can maintain the safety of our operations and personnel 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 the business of Gran Tierra. 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 may also experience difficulties in certain jurisdictions in our efforts to obtain suitably qualified staff and retain staff that are willing to work in that jurisdiction. We do not currently carry life insurance for our key employees.

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 in order 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 Gran Tierra 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.

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 sales in Argentina will depend on a relatively small group of customers, and currently, on just one customer. 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 sales contracts. We cannot provide any certainty as to when the situation will be resolved or what the final outcome will be.

Strategic 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 Gran Tierra's 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 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 may not be able to establish these strategic 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 Gran Tierra.

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

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

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. In 2010, there has been an increased presence of illegitimate unionization activities in the Putumayo Basin by the Sindicato de Trabajadores Petroleros del Putumayo ("Sintrapetorputumayo"), which has disrupted our operations from time to time and may do so 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.

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 company’s functional currency. Since we began operating in Argentina (September 1, 2005), the rate of exchange between the Argentine peso and US dollar has varied between 3.05 pesos to one US dollar to 3.96 pesos to the US dollar, a fluctuation of approximately 30%. Exchange rates between the Colombian peso and US dollar have varied between 2,632 pesos to one US dollar to 1,648 pesos to one US dollar since September 1, 2005, a fluctuation of approximately 60%.

In addition, a foreign exchange loss of $18.7 million, of which $14.8 million is an unrealized non-cash foreign exchange loss, was recorded in 2010 and was primarily due to 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 6% in the US dollar against the Colombian Peso in the year ended December 31, 2010 resulted in the foreign exchange loss.

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

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

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.

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, foreign owned 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.

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.

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

The crude 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 crude 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 crude 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, Refinor S.A., and the price is negotiated on a month by month basis. The Provincial Governments have also been hurt by these changes as their effective royalty 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 Refinor 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.

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.

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 stockholders, 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. 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 Oil and Gas Reserves 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 company's 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 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 mechanical 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 or to Obtain Them on a Timely Basis 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.

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 to 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 2010, we recorded a ceiling test impairment loss of $23.6 million in our Argentina cost center.

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 fourth quarter of 2010.   In February 2011, these operations were suspended and the wellbore will be abandoned due to a number of operational challenges encountered. Gran Tierra Energy continues 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 may become responsible for costs associated with abandoning and reclaiming 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.

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

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, and $79 in 2010, demonstrating the inherent volatility in the market. 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 and 2010 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 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, blow-outs, 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 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; and
- changes in the social, political and/or legal climate in the regions in which we will operate.

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;
- changes in the valuation of similarly situated companies, both in our industry and in other industries;
- changes in analysts' estimates affecting our company, our competitors and/or our industry;
- changes in the accounting methods used in or otherwise affecting our industry;
- additions and departures of key personnel;
- announcements of technological innovations or new products available to the oil and natural gas industry;
- announcements by relevant governments pertaining to incentives for alternative energy development programs;

- fluctuations in interest rates, exchange rates and the availability of capital in the capital markets; and

- significant sales of our common stock, including sales by future investors in future offerings we expect to make to raise additional capital.

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 stockholders 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

Not applicable.

Item 2. Properties

Offices

We currently lease office space in: Calgary, Alberta; Buenos Aires and Vespucio, Argentina; Bogota, Colombia; Rio de Janiero, Brazil; and Lima and Iquitos, Peru.

We have five Calgary leases, the first two expire January 31, 2013, the third expires October 31, 2012, the fourth expires April 30, 2014 and the fifth expires on October 30, 2015. Their cost is $12,305 per month, $6,641 per month, $4,087 per month, $13,224 per month and $34,278 per month respectively. We have subleased the first lease for $4,444 per month from February 1, 2011 to January 30, 2013 to a company for which our President and Chief Executive Officer serves as an independent Director. We have subleased the third lease for $3,794 per month from July 1, 2010 to October 29, 2012 and the fourth lease for $12,125 per month from February 1, 2009 to August 31, 2011. We plan on subleasing the second as well. Since March 2010, all Calgary staff is housed in the space covered by our fifth sub-lease.

Our three Buenos Aires, Argentina leases expire January 31, 2012, March 7, 2012 and July 17, 2012 and cost $2,877 per month, $2,455 per month and $2,743 per month respectively. We also have a lease in Vespucio, Argentina which expires February 28, 2011 and has a cost of $946 per month.

We have two leases in Bogotá, Colombia. They expire February 28, 2011 and February 1, 2012 and cost $2,029 per month and $87,065 per month, respectively.

We have office space leased in Rio de Janeiro, Brazil until September 30, 2012 at a cost of $12,380 per month.

In Lima, Perú, we have one office lease expiring August 31, 2014 at a cost of $8,229 per month and two houses for staff residences with leases expiring June 1 2012 and August 2, 2012 with a cost of $2,350 per month and $1,200 per month respectively. In Iquitos, Perú, we have a combination office and staff residence and an additional staff residence with leases expiring October 31, 2011 and September 8, 2012 at a cost of $1,055 per month, and $534 per month, respectively. The properties remaining on lease are in good condition and we believe that they are sufficient for our office needs for the foreseeable future.

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 interests 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 Technical Evaluation Areas in the Putumayo basin (Putumayo West A and Putumayo West B) were acquired in 2007. We relinquished the Primavera Block in 2007 and we relinquished the Talora Block in 2009.

In November 2008, we acquired Solana which increased our interest in the Guayuyaco and Chaza blocks, and added 7 blocks in 3 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 Guachira, Guachiria Sur and Guachiria Norte blocks and we relinquished our rights to the San Pablo Block.

In 2009, we converted portions of the two Technical Evaluation Areas 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 3 blocks in Colombia Bid Round 10 which are subject to ANH approval (Cauca 6, Cauca 6 and Putumayo-10). In 2010, we also acquired an operated interest in the Putumayo-1 Block. We currently have interests in 16 blocks in Colombia, and are operator of 15 blocks.

Currently, the Guayuyaco, Santana, Chaza and Garibay blocks have producing oil wells. The Magangue Block has 1 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 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 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%. Our production from the Costayaco field is also subject (starting in October 2009) to an additional royalty that applies when cumulative gross production from a field is greater than 5 million barrels. This additional royalty applies to 30% of the gross production and is calculated on the difference between WTI and an oil quality based index. As the law stands currently, any new discoveries on ANH contracted blocks will also be subject to this additional royalty once each new field exceeds 5 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 5 million barrels. 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 original interests in the five blocks purchased from Argosy that we still hold (Santana, Guayuyaco, Chaza, Rio Magdalena, Mecaya) are subject to a 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.

Santana Block

The Santana Block contract was signed in July 1987 and covers 1,119 gross acres and includes 14 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. Ecopetrol holds the remaining interest. The block has been producing since 1991. Under the Shared Risk Contract, Ecopetrol initially backed in to 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 took, for a total ownership of 65%.

The production contract expires in 2015, at which time the property will be returned to the government. As a result, there will be no reclamation costs.

In 2010, we performed minor facility maintenance. For 2011 there are no capital expenditures planned for Santana.

Guayuyaco Block

The Guayuyaco Block contract was signed in September 2002 and covers 52,366 gross acres, which includes the area surrounding the four 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. 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 two producing wells; Juanambu-1 began commercial production on November 8, 2007 and Juanambu-2 began production in March 2010. Ecopetrol has the option to back-in to a 30% participation interest in any other new discoveries in the block.

The contract expires in two phases: the exploration phase and the production phase. The exploration phase expired in 2005 and the production phase expires in 2030. We have completed all of our obligations in relation to the exploration phase of the contract. The property will be returned to the government upon expiration of the production contract. As a result, there will be no reclamation costs.

In 2010, we drilled Juanambu -2 and we also performed work on electrical systems, flowlines, storage tanks and other production facilities. In 2011, we plan to drill one development well (Juanambu-3) and conduct two exploration 3D seismic programs.

Chaza Block

The Chaza Block covers 80,242 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.

This block entered the 6th exploration phase in December 2010 which has a six month duration and an obligation to drill one exploration well. The contract for this field expires in two phases. The exploration phase currently expires in 2011 and the production phase ends in 2033. The property will be returned to the government upon expiration of the production phase. We are planning to apply for an additional exploratory program allowable under our contract which would extend the exploration phase of the contract for an additional four years. Within 60 days following the date of the return of the property, 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 2010, we drilled one successful exploration well, and plugged and abandoned a second exploration well, Dantayaco-1. Pacayaco-1 was suspended while we acquired and interpreted additional seismic and either a new well or a sidetrack of the existing well is planned late in the second quarter of 2011. In the Costayaco field, Costayaco-11 was drilled as a development well and the Costayaco-12 and Costayaco-13 development wells were in progress at year-end. We performed upgrades to the pumping station, battery and support facilities and initiated a project to electrify the field. The electrification will reduce our dependence on diesel fuel for power and lead to cost savings. In the Moqueta field, we drilled three delineation wells, Moqueta-2, 3 and 4 (in progress at year end and testing expected to be completed by March 2011). Two seismic programs were acquired in the Chaza Block; the Rio Guineo 100 square kilometer 3D program and the Moqueta 50 kilometer 2D program.

In 2011, one exploration well is planned for the Chaza Block, Canangucho-1 (spud February 2011), and up to three development wells. One water injector well is planned for the Costayaco field and up to two development wells are planned for the Moqueta field (Moqueta 5 and 6). The remaining facility upgrades in the Costayaco field are planned to be completed in 2011. In addition, the Moqueta pipeline and production facilities are planned to be completed with the expectation of initial production early in the second quarter of 2011. Two seismic acquisition programs are planned for 2011; the Moqueta 120 square kilometer 3D program and the Verdeyaco 3D program.

Azar Block

We acquired an 80% interest in the Azar Block through a farm-in agreement entered into in late 2006. This exploration block covers 47,226 gross acres and we are the operator. Pursuant to the terms of the farm-in agreement we were obligated to pay the original owner’s 20% share of future costs, in addition to our own 80% share. In mid-2007 we farmed out 50% of our interest to a third party. The third party will pay 100% of our 80% share of exploration and development costs for the first three periods of the exploration contract, and we remained obligated to pay 20% of costs under our 2006 farm-in agreement. The agreement has now moved to its next phase, in which the carried partner will pay 50% of its share (10% of the total cost) of the work for the current exploration period to maintain its 20% interest. If the carried partner does not pay its share of the costs, then it will reduce its ownership percentage to 10%. We are now in the fourth exploration period which carries a commitment to drill one well. There are two more exploration periods that follow, each lasting 12 months and including an obligation to drill one exploration well. The exploration phase of the contract expires in 2013 for this property. 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 2010, we acquired 75 square kilometers of 3D seismic. In 2011, we plan to drill one exploration well.

Piedemonte Norte Block

In June 2009, we completed the conversion of our Technical Evaluation Areas in the Putumayo Basin to blocks with ANH Exploration and Exploitation Contracts. Piedemonte Norte covers 78,742 gross acres and is held 100% by Gran Tierra and was part of the Putumayo West A Technical Evaluation Area. From June to December 2009 we were in a pre-exploration phase in which we performed environmental evaluation and survey work. The first exploration period expires in June 2011. There are a total of 6 exploration periods and the exploration phase of the contract expires in December 2015. The exploitation phase would expire 24 years after commerciality of a discovery is approved. The first exploration period contains a commitment to acquire, process and interpret 70 kilometers of 2D seismic by June 2011.

In 2010, we acquired 20 kilometers of 2D seismic. In 2011, we plan to acquire 50 kilometers of 2D seismic and drill one stratigraphic well.

Piedemonte Sur Block

Piedemonte Sur was also part of the Putumayo West A Technical Evaluation Area and became an exploration block with an ANH Exploration and Exploitation Contract in June 2009. Piedemonte Sur covers 73,898 gross acres and is held 100% by Gran Tierra. From June to December 2009, we were in a pre-exploration phase in which we performed environmental evaluation and survey work. We are now in the first exploration period of a total of six periods in the contract. The exploration phase ends in December 2015, and the exploitation phase would expire 24 years after commerciality of a discovery is approved. The first exploration period contains a commitment to drill one exploration well to a minimum depth of 3,000 feet, by December 16, 2010.

In 2010, we acquired 20 kilometers of 2D seismic and this program extended into 2011. In 2011, we plan to complete the 2D seismic acquisition program and drilling of the first exploration well. Pre-drill operations for this exploratory well, Taruka–1, were in progress at year-end and formal extension of the first phase was requested from the ANH. Taruka-1 was spud in early January 2011 and plugged and abandoned in February 2011.

Rumiyaco Block

Rumiyaco was part of the Putumayo West B Technical Evaluation Area 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% by Gran Tierra. From June to December 2009, we were in a pre-exploration phase in which we performed environmental evaluation and survey work. We are now in the second exploration period of a total of six periods in the contract. The exploration phase ends in December 2015, and the exploitation phase would expire 24 years after commerciality of a discovery is approved. The second exploration period contains a commitment to drill one exploration by September 2011.

In 2010, we acquired 95 square kilometers of 3D seismic. In 2011, we plan to drill one exploration well (Rumiyaco-1).

Magangué Block

Solana acquired the Magangue Block in October 2006. It is held pursuant to an Ecopetrol Association Contract and covers an area of 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 Güepajé gas field.

This block borders the La Creciente Block where there was a significant gas discovery in the same productive formation as the Güepajé gas field in 2006. The contract expires in 2017. The exploration phase for this block is over and there are no obligatory work commitments.

In 2010, we purchased equipment for hydrocarbon dew point control to meet pipeline specifications. In 2011, we plan to do minor facility upgrades.

Garibay Block

Solana acquired the Garibay Block in October 2005. The block covers 75,936 gross acres and we have a working interest of 50%. The block is located approximately 170 kilometers east of Bogotá and is subject to an ANH contract. On November 17, 2007, a farm-out agreement was signed with a third party under which they financed the drilling of the Topocho-1 exploration well in return for a 50% working interest in the block and becoming the operator. This well was a dry hole.

We are currently in the 6th and final period of the exploration contract, which expires October 24, 2011. There is an obligation to drill one exploration well in the current exploration period.

In 2010, one exploration well was drilled (Jilguero-1), which resulted in an oil discovery. In 2011, we plan to drill one exploration well which will satisfy the exploration obligation.

Rio Magdalena

The Rio Magdalena Association Contract with Ecopetrol was signed in February 2002. The Rio Magdalena Block covers 72,312 gross acres and is located approximately 75 kilometers west of Bogota, Colombia. This is an exploration block and there are no reserves at this time. We are the operator of the block and hold a 44% working interest with one partner holding a 56% working interest. The production contract expires 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 to any discoveries on the block upon commercialization. In 2010 we submitted a proposal to Ecopetrol to relinquish 50% of the area in the block. Our relinquishment proposal was accepted by Ecopetrol.

In 2010 one appraisal well was drilled (Popa-3). The well is currently suspended pending further testing and evaluation. For 2011, there are no capital expenditures planned for Rio Magdalena.

Mecaya

The Mecaya Exploration and Exploitation contract 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 currently have a 15% participation interest and three partners with 27%, 28% and 30% interest. We are in exploration period three of this contract and are obliged to drill one exploration well, and re-enter a previously drilled 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 periods following, each of which are 12 months in duration. The third period has an obligation to acquire seismic data, and the fourth period 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 2010, there were no capital expenditures and no capital expenditures are planned for 2011.

Catguas Block

Solana acquired the Catguas Block in November 2005. We are the operator of the block which covers 393,150 gross acres in the Catatumbo Basin. One partner has a 15% working interest in the southern 70% of the block and a 50% working interest in the remainder of the block. The block is held under an ANH contract.

There are no wells producing on this block. We are in the third period of the exploration portion of the contract, out of a total of six periods. This period expired June 5, 2010, and had an obligation to re-enter an existing well and drill two exploration wells. All remaining periods are 12 months in length and carry a work obligation of one well. The exploitation phase would last 24 years from any declaration of a commercial discovery.

In 2010, there was no exploration activity on this block. There is no activity planned for 2011 as the block contract is in suspension by ANH as a result of force majeure.

Cauca 6 Block

We were awarded the Cauca 6 Block in June 2010 in the Colombia Bid Round 10, pending ANH approval. The block covers 571,098 gross acres in the Cauca-Patia basin and we hold a 100% working interest. After the contract is signed, the initial six month phase of community consultation will begin. The first exploration phase of the contract will require the acquisition of 200 kilometers of 2D seismic and the drilling of one stratigraphic well.

In 2011, we plan to acquire aeromagnetic and aerogravity surveys as well as geological studies.

Cauca 7 Block

We were awarded the Cauca 7 Block in June 2010 in the Colombia Bid Round 10, pending ANH approval. The block covers 785,452 gross acres in the Cauca-Patia basin and we a hold a 100% working interest. After the contract is signed, the initial six month phase of community consultation will begin. The first exploration phase of the contract will require the acquisition of 250 kilometers of 2D seismic and the drilling of one stratigraphic well.

In 2011, we plan to acquire aeromagnetic and aerogravity surveys as well as geological studies.

Putumayo 10 Block

We were awarded the Putumayo 10 Block in June 2010 in the Colombia Bid Round 10, pending ANH approval. The block covers 114,096 gross acres in the Putumayo basin and we hold a 100% working interest. After the contract is signed, the initial six month phase of community consultation will begin. The first exploration phase of the contract will require the acquisition of 70 kilometers of 2D seismic and the drilling of two exploration wells.

In 2011, we plan to acquire 100 kilometers of 2D seismic and drill one exploration well.

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 first phase of this contract expires in September 2012 and requires the acquisition of 159 square kilometers of 3D seismic and the drilling of one exploration well.

In 2011 we plan to acquire 220 square kilometers of 3D seismic.

Oil and Gas Properties - 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 93.18% interest in Valle Morado. In 2009 we relinquished our rights to the Nacatimbay Block and in 2011 we plan to relinquish our interest in the Ipaguazu Block. Our Argentina properties are located in the Noroeste Basin in northern Argentina.

Palmar Largo

The Palmar Largo joint venture block encompasses 341,500 gross acres. This asset is comprised of several producing oil fields in the Noroeste Basin. We own a 14% working interest in the Palmar Largo joint venture, which we purchased in September 2005. A total of 14 gross wells are currently producing.

The Palmar Largo Block rights expire in 2017 but provide for a ten-year extension. We do not have any outstanding work commitments. On expiry of the block rights, ownership of the producing assets will revert to the provincial government.

In 2010, only regular field maintenance and workover activities were performed at Palmar Largo. In 2011, only regular field maintenance and workover activities are planned.

Ipaguazu

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. We are the operator of the block. The oil and gas field was discovered in 1981 and produced approximately 100 thousand barrels of oil and 400 million cubic feet of natural gas until 2003. The Ipaguazu Block covers 21,745 gross acres. The Ipaguazu Block rights expire in 2016 with a ten year extension if a discovery is made. We do not have any outstanding work commitments. At expiry of the block rights, ownership of the producing assets will revert to the provincial government In April 2010, production operations at the Ipaguazu-1 well were suspended due to low well productivity. We filed an application for relinquishment of the Ipaguazu Block in 2010 and are awaiting government approval.

El Vinalar

In June 2006, we acquired a 50% working interest in the El Vinalar Block, which covers 61,035 gross acres.

The El Vinalar rights expire in 2016 with a ten year extension if a discovery is made. We do not have any outstanding work commitments. At expiry of the block rights, ownership of the producing assets will revert to the provincial government.

In 2010, we performed regular field maintenance and workovers in El Vinalar. Only regular field maintenance and workover activities are planned in 2011.

El Chivil

We purchased El Chivil in 2006. We are the operator and hold a 100% working interest in El Chivil which covers 30,393 gross acres. The Chivil field was discovered in 1987. Three wells were drilled with two remaining in production. The contract for this field expires in 2015 with the option for a ten year extension.

In 2010, we performed regular field maintenance and workovers in El Chivil. Only regular field maintenance and workover activities are planned in 2011.

Surubi

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 REFSA farmed-in to the block for a 15% working interest, and is paying its share of well costs from its share of production from Proa-1. The contract for this block expires in 2023 and we have no outstanding commitments related to the block contract.

In 2010, we performed regular maintenance and workover activities at Proa-1. For 2011, we plan to drill a development well (Proa-2) in addition to performing regular maintenance and workover activities.

Valle Morado

We purchased the Valle Morado Block at the end of 2006. Valle Morado covers 49,099 gross acres and we are the operator with a 93.2% working interest. The remaining 6.8% interest is held equally by two other companies. The previous owners had the option to back-in for an 18% working interest under certain circumstances; however, we paid out the owners and eliminated this option during 2010. The contract for this block expires in 2034 and we have no outstanding commitments related to the block contract.

Valle Morado GTE.St.VMor-2001 was first drilled in 1989. The original owner subsequently 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 and was shut-in in 2001 due to water incursion. In 2008, we successfully re-entered the well.

In July 2010, we commenced a re-entry and sidetrack operation on the GTE.St.VMor-2001 well. In February 2011, these operations were suspended and the wellbore will be abandoned due to a number of operational challenges encountered. Gran Tierra Energy continues to review alternatives associated with the field development.

Santa Victoria

We purchased the Santa Victoria Block late in 2006. Santa Victoria covers 1,033,889 gross acres and we are the operator with a 100% working interest. It is an exploration block with no production history. The contract’s exploration period expired in December 2010 however we received a 90 day extension to March 29, 2011. We are using the extension to allow for the interpretation of the 202 square kilometers of 3D seismic acquired in 2010 and determine whether to proceed into the next phase of the contract. We have no other outstanding commitments related to the block contract.

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. The acquisition in 2010 of these four blocks is subject to approval by the Government of Peru.

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 royalty of 20%. This royalty structure applies to all 6 blocks in Peru that we have an interest in.

Block 122 and Block 128

We were awarded two exploration blocks in Peru in the last quarter of 2006 under a license contract for the exploration and exploitation of hydrocarbons. Block 122 covers 1,217,651 gross acres and Block 128 covers 2,218,389 gross acres. In February 2011, we relinquished 20%, or 443,678 gross acres in Block 128. The blocks are located in the eastern flank of the Maranon Basin in northern Peru, on the crest of the Iquitos Arch. There is a financial commitment of $3.5 million over the seven years for each block which includes technical studies, seismic acquisition and the drilling of exploration wells. We are currently in the second phase of each of these block's contracts. In 2010, we received EIA approvals for seismic and drilling operations for these blocks and acquired 260 kilometers of 2D seismic on Block 128. At year end, the 290 kilometer 2D seismic acquisition was ongoing at Block 122. Exploration wells are planned for Block 128 (spud February 2011) and for Block 122 in the third quarter of 2011. Up to two more exploration wells are contingent upon the results of these wells.

Block 123, Block 124 and Block 129

In September 2010, we acquired a 20% working interest in Block 123, Block 124, and Block 129, subject to government approval. These three blocks have a total area of approximately 6.7 million acres and Burlington Resources Peru Limited (a wholly owned subsidiary of ConocoPhillips) is the operator of these blocks. We are currently in the second phase of each of the contracts which require seismic acquisition totaling 1,400 kilometers for all blocks prior to phase completion. In 2010, 747 kilometers of 2D seismic was acquired on these blocks. In 2011, we plan to complete the seismic commitments required under phase two for Blocks 123 and Block 129. We may request an extension of phase two in Block 124 to facilitate completion of the seismic commitment for that block.

Block 95

In December 2010, we acquired a 60% working interest in Block 95, subject to government approval. Block 95 has a total area of 1.3 million gross acres. We will be the operator of Block 95. We are currently in phase three of the contract which has been delayed as a result of force majeure. Once force majeure has ended, we plan to apply to extend the current phase to provide sufficient time to complete the well commitment. Block 95 contains a drill ready prospect which we plan to drill in 2011.

Oil and Gas Properties - Brazil

Gran Tierra 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 Reconcavo Basin, subject to government approval.

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 prolific Reconcavo Basin. This basin covers an area of approximately 10,000 square kilometers, contains 129 fields, and has produced over 1.5 billion barrels of oil to date (source: IHS Inc., 2010). Production from this basin is mainly light oil ranging between 35 and 40 API. These four blocks have a total area of 27,075 gross acres. Gran Tierra is awaiting regulatory approval from Brazil's ANP to recognize Gran Tierra as the operator of these exploration blocks. All of our blocks in Brazil are subject to an 11% royalty, which consists of a 10% crown royalty and a 1% landowner royalty which applies to onshore blocks. All four blocks are in phase one of the contracts which expire March 12, 2011. An application for a six month extension has been made for Blocks REC-T-129, REC-T-142, and REC-T-224. The first phase for each of Blocks REC-T-129 and REC-T-142 requires the drilling of an exploratory well and, for Block REC-T-224,14 requires the acquisition of 35 square kilometers of 3D seismic. There is no remaining phase one commitment for Block REC-T-155.

In the third and fourth quarters of 2010, 93 square kilometers of 3D seismic was acquired over Blocks REC-T-129, REC-T-142 and REC-T-155. An additional 35 square kilometers of 3D seismic survey is planned for the first quarter of 2011 for Block REC-T-224. The 1-ALV-2-BA well on Block REC T-155 is presently producing approximately 500 BOPD gross (350 BOPD net after royalties). We plan to dual complete this well in the first quarter of 2011 and plan to drill two appraisal wells to further develop this discovery. In 2011, we plan to drill four exploration wells on Blocks REC-T-129, REC-T-142 and REC-T-155. The drilling of these wells meets or exceeds each blocks' phase one commitments. Blocks REC-T-129, REC-T-142, and REC-T-224 will require an additional exploration well to satisfy the phase two commitments and these are planned for 2012. In January 2011, Gran Tierra opened an office in Salvador, Brazil to manage the field operations for the Reconcavo Basin blocks.

Reserves

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

The process of estimating oil and gas reserves is complex and requires significant judgment, as discussed in Item 1A. "Risk Factors". As a result we have developed internal policies for estimating and evaluating reserves, and 100% of our reserves are audited by an independent reservoir engineering firm, GLJ Petroleum Consultants Ltd., at least annually. 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.

The policies we have developed are applied company wide, and are comprehensive in nature. The result of the policies is SEC compliant reserve estimates and disclosures. The policy is 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.

The primary internal technical person in charge of overseeing the preparation of our reserve estimates is the Manager of Reservoir Engineering. He has a bachelor's degree of science in petroleum engineering and is a professional engineer and member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta. He is currently responsible for our engineering activities including reserves reporting, asset evaluation, field development and monitoring production operations. 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 Vice President, International 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.

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 that to decrease.

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

• 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 to the cost of a new well; and

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

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

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

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

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

The following table sets forth our oil reserves net of all royalties as of December 31, 2010 (all quantities in thousands of barrels of oil, “mbbls”, or millions of cubic feet of natural gas, “Mmcf”). 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. When deterministic methods are used, as they are in our case, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. 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.

	Reserves	
Reserves Category	Liquids* mbbls	Natural Gas Mmcf
PROVED		
Developed:		
Colombia	18,528	1,232
Argentina	940	-
Undeveloped		
Colombia	3957	-
Argentina	173	-
TOTAL PROVED	23,598	1,232
PROBABLE		
Developed		
Colombia	4,060	147
Argentina	534	-
Undeveloped		
Colombia	2,790	-
Argentina	35	-
TOTAL PROBABLE	7,419	147
POSSIBLE		
Developed		
Colombia	5,851	181
Argentina	427	-
Undeveloped		
Colombia	8,371	-
Argentina	1,657	41,880
TOTAL POSSIBLE	16,306	42,061

*Liquids include oil and Natural Gas Liquids. We have Natural Gas Liquids reserves in small amounts in Argentina only. Colombia Liquids reserves are 100% oil.

Proved Undeveloped Reserves

In Colombia, our proved undeveloped reserves increased to 4.0 million barrels (“Mmbbls”) at December 31, 2010 from 0.6 Mmbbls at December 31, 2009. Approximately 70% of these proved undeveloped reserves are located in our Costayaco field, under development in 2011. Approximately 30% of the proved undeveloped reserves are located in our Moqueta discovery, which will be developed in 2011. Our proved undeveloped reserves in Argentina decreased slightly from 211,000 barrels at December 31, 2009 to 173,000 barrels at December 31, 2010 due to a revision to forecast development activity. We expect to develop these reserves in 2011.

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

Price Case	Proved Reserves Liquids (mbbls)	Proved Reserves Natural Gas (Mmcf)	Probable Reserves Liquids (mbbls)	Probable Reserves Natural Gas (Mmcf)	Possible Reserves Liquids (mbbls)	Possible Reserves Natural Gas (Mmcf)
WTI +10%						
Colombia	22,185	1,232	6,670	148	14,113	180
Argentina	1,113	-	569	-	2,083	41,880
Total	23,298	1,232	7,239	148	16,196	42,060
WTI – 10%						
Colombia	22,709	1,232	6,889	148	14,472	180
Argentina	1,113	-	569	-	2,083	41,880
Total (1)	23,822	1,232	7,458	148	16,555	42,060

(1) The total proved Liquids is higher as a result of a 10% decrease in WTI as compared to a 10% increase in WTI. The lower price results in reduced additional government and third party royalties paid, increasing the net after royalty volumes.

The price cases presented involve changes to the WTI price – one 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 in Item "1 Business" under the caption "Markets and Customers". The price in Argentina is not sensitive to changes in the WTI price, 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.

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, 2010 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. 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, 2010.

	2010 Gross	2010 Net	2009 Gross	2009 Net	2008 Gross	2008 Net
Colombia						
Exploration						
Productive	4.00	3.50	-	-	1.00	0.40
Dry	1.00	1.00	2.00	0.70	1.00	0.40
In Progress	3.00	2.43	1.00	1.00	-	-
Development						
Productive	2.00	1.70	3.00	3.00	3.00	1.50
Dry	-	-	1.00	1.00	-	-
In Progress	2.00	2.00	1.00	0.70	1.00	1.00
Total Colombia	12.00	10.63	8.00	6.40	6.00	3.30
Argentina						

Exploration						
Productive	-	-	-	-	1.00	0.85
Dry	-	-	-	-	-	-
In Progress	1.00	0.93	-	-	-	-
Development						
Productive	-	-	-	-	-	-
Dry	-	-	-	-		
In Progress	-	-	-	-	-	-
Total Argentina	1.00	0.93	-	-	1.00	0.85
Peru						
Exploration						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	-	-	-	-	-	-
Development						
Productive	-	-	-	-	-	-
Dry	-	-	-	-	-	-
In Progress	-	-	-	-	-	-
Total Peru	-	-	-	-	-	-
Total	13.00	11.56	8.00	6.40	7.00	4.15

Following are the results as of February 18, 2011 of wells in progress at December 31, 2010:

	Productive		Dry		Still in Progress	
	Gross	Net	Gross	Net	Gross	Net
Colombia	-	-	-	-	5.00	4.43
Argentina	-	-	1.00	0.93	-	-
Peru	-	-	-	-	-	-
Total	-	-	1.00	0.93	5.00	4.43

Well Statistics

The following table sets forth our producing wells as of December 31, 2010.

	Oil Wells (1)		Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Colombia	26.00	15.70	1.00	0.42	27.00	16.12
Argentina	32.00	8.35	-	-	32.00	8.35
Peru	-	-	-	-	-	-
Total	58.00	24.05	1.00	0.42	59.00	24.47

(1) Includes 2.0 gross and net water injector wells in Colombia and 12.0 gross and 1.68 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, 2010.

	Developed		Undeveloped (1)		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia	230,310	163,929	936,961	654,594	1,167,271	818,523
Argentina	572,839	238,472	1,055,634	1,055,634	1,628,473	1,294,106
Peru	-	-	3,436,040	3,436,040	3,436,040	3,436,040
Brazil	-	-	-	-	-	-
Total	803,149	402,401	5,428,635	5,146,268	6,231,784	5,548,669

(1) Not included in undeveloped acreage is land acquired through agreements for which government approval is pending. This undeveloped land includes 1,470,645 gross and net acres in Colombia, 7,995,101 gross (5,544,820 net) in Peru, and 27,076 gross (18,953 net) acres in Brazil. Additionally, the undeveloped land acreage for Argentina includes 21,745 gross and net acres in the Ipaguazu Block for which application for relinquishment has been filed and we are awaiting government approval and 443,678 gross and net acres in Block 128 in Peru, which was relinquished in February 2011.

Our net developed acreage in Colombia includes acreage in the Santana Block (less than 1%); the Magangue Block (1%); the Guayuyaco Block (4%); the Garibay Block (5%); and the Chaza Block (10%). Our net undeveloped acreage in Colombia, not including acreage acquired through agreements still subject to government approval, is in the Putumayo 10, Cauca 6 and Cauca 7 blocks (less than 1% each); the Mecaya Block (1%); the Azar Block (2%); the Rio Magdalena Block (4%); the Catguas A Block (7%); the Putumayo 1 Block (8%); the Piedemonte Sur Block (9%); the Piedemonte Norte and Rumiyaco blocks (10% each); and the Catgua B Block (29%).

In Argentina, our net developed acreage includes acreage in the El Chivil Block (2.3%); the El Vinalar Block (2.4%); the Valle Morado Block (3.5%); the Palmar Largo Block (20%); and the Surubi Block (6.5%). Our net undeveloped acreage in Argentina is in the Santa Victoria Block (98%) the Ipaguazu Block (2%), which currently has an application to relinquish filed with the government.

In Peru, our net undeveloped acreage, not including that acquired through agreements for which government approval is pending or that which was relinquished after year-end, includes acreage in Block 122 (35%) and Block 128 (65%).

In Brazil all our net undeveloped acreage was acquired in an agreement still pending government approval.

Item 3. Legal Proceedings

Ecopetrol and 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 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. Closing arguments were presented by all parties during 2009. We are awaiting the Court's decision. 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. Ecopetrol is claiming damages of approximately $5.5 million.

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. Removed and reserved

End of Item 4

Executive Officers of the Registrant

Set forth below is information regarding our executive officers as of February 18, 2011.

Name	Age	Position
Dana Coffield	52	President and Chief Executive Officer; Director
Martin H. Eden	63	Chief Financial Officer
Shane O'Leary	54	Chief Operating Officer

David Hardy	56	General Counsel, Vice-President Legal, and Secretary
Rafael Orunesu	55	President and General Manager Gran Tierra Energy Argentina
Julian Garcia	52	President and General Manager Gran Tierra Energy Colombia
Julio Cesar Moreira	49	President and General Manager Gran Tierra Energy Brasil

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.

Martin H. Eden, Chief Financial Officer. Mr. Eden joined our company as Chief Financial Officer on January 2, 2007. 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 from Henley Management College/Brunel University, England, and is a member of the Institute of Chartered Accountants of Alberta and the Institute of Chartered Accountants in England and Wales.

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 4 of his 8 years in the Offshore and International Division of Encana, Mr. Hardy led the Legal and Commercial Negotiations Group. He has experience in new ventures activities and operations involving 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 Bachelor of Laws Degree from the University of Calgary 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, incorporating 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 Nuequén 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.

Julian Garcia, President and General Manager Gran Tierra Energy Colombia. Mr. Garcia joined our company as President and General Manager Gran Tierra Energy Colombia in December 2009. Mr. Garcia has more than 25 years of petroleum industry experience in Colombia and internationally. He has extensive experience in all aspects of the petroleum industry, including exploration and production operations, commercial, finance, project management and strategic leadership. He has held a range of progressively senior positions, technical and financial, at companies including Ecopetrol, BP, and the National Hydrocarbon Agency, where he was Technical Director. Most recently, Mr. Garcia was General Manager for Emerald Energy Plc Colombia, where the company grew reserves 10-fold in less than five years; he was responsible for all operations and businesses in Colombia and Peru with 11 blocks in 6 basins. Mr. Garcia holds a Bachelors of Civil Engineering and a Masters in Economics from Universidad de Los Andes, a Masters in Civil Engineering from Colorado State University USA, and a Masters of Business Administration from the University of Birmingham, UK.

Julio Cesar Moreira, President 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).

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 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 18, 2011 there were approximately: 51 holders of record of shares of our common stock and 240,857,632 shares outstanding with $0.001 par value; and one share of Special A Voting Stock, $0.001 par value representing approximately 9 holders of record of 7,811,112 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 10 holders of record of 9,539,042 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, 2009 through the end of the fourth quarter of 2010, 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 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
Fourth Quarter 2009	$	6.00	$	3.99
Third Quarter 2009	$	4.26	$	2.92
Second Quarter 2009	$	3.51	$	2.31
First Quarter 2009	$	3.50	$	2.06

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.

Unregistered Sales of Equity Securities

On 16 separate dates beginning on October 1, 2010 and ending on December 31, 2010, we sold an aggregate of 689,054 shares of our common stock for an aggregate purchase price of $764,582. These shares were issued to 29 holders of warrants to purchase shares of our common stock upon exercise of the warrants. The shares were issued to these holders in reliance on Section 4(2) under the Securities Act, in that they were issued to the purchasers of the warrants, who had represented that they were accredited investors as defined in Regulation D under the Securities Act. On October 14, 2010 we issued 158,730 shares of our common stock to one holder of exchangeable shares, which were issued by a subsidiary of Gran Tierra in a share exchange on November 10, 2005. The shares were issued to this holder in reliance on Regulation S promulgated by the SEC as the investor was not a resident of the United States.

Performance Graph

	12/05	12/06	12/07	12/08	12/09	12/10
Gran Tierra Energy Inc	100	43.12	94.93	101.45	207.61	291.67
Russell Small Cap Completeness	100	114.89	120.46	73.51	101.22	128.18
Dow Jones US Exploration & Production TSM	100	105.08	147.43	86.94	123.04	145.68

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

Item 6. Selected Financial Data

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

	Year Ended December 31, 2010	Year Ended December 31, 2009	Year Ended December 31, 2008	Year Ended December 31, 2007	Year Ended December 31, 2006
Statement of Operations Data					
Revenues and other income					
Oil and natural gas sales	$ 373,286	$ 262,629	$ 112,805	$ 31,853	$ 11,721
Interest	1,174	1,087	1,224	425	352
Total revenues and other income	374,460	263,716	114,029	32,278	12,073
Expenses					
Operating	59,446	40,784	19,218	10,474	4,233
Depletion, depreciation, accretion and impairment	163,573	135,863	25,737	9,415	4,088
General and administrative	40,241	28,787	18,593	10,232	6,999
Liquidated damages	-	-	-	7,367	1,528
Derivative financial instruments (gain) loss	(44)	190	(193)	3,040	-
Foreign exchange (gain) loss	16,838	19,797	6,235	(78)	371
Total expenses	280,054	225,421	69,590	40,450	17,219
Income (loss) before income taxes	94,406	38,295	44,439	(8,172)	(5,146)
Income tax expense	(57,234)	(24,354)	(20,944)	(295)	(678)
Net income (loss)	$ 37,172	$ 13,941	$ 23,495	$ (8,467)	$ (5,824)
Net income (loss) per common share — basic	$ 0.15	$ 0.06	$ 0.19	$ (0.09)	$ (0.08)
Net income (loss) per common share — diluted	$ 0.14	$ 0.05	$ 0.16	$ (0.09)	$ (0.08)

Balance Sheet Data	As at December 31, 2010	As at December 31, 2009	As at December 31, 2008	As at December 31, 2007	As at December 31, 2006
Cash and cash equivalents	$ 355,428	$ 270,786	$ 176,754	$ 18,189	$ 24,101
Working capital (including cash)	265,835	215,161	132,807	8,058	14,541
Oil and gas properties	721,157	709,568	765,050	63,202	56,093
Deferred tax asset - long term	-	7,218	10,131	1,839	444
Total assets	1,249,254	1,143,808	1,072,625	112,797	105,537
Deferred tax liability and deferred remittance tax - long term	205,606	217,528	214,210	10,567	9,876
Other long-term liabilities	4,469	4,258	4,251	1,986	634
Shareholders’ equity	$ 886,866	$ 816,426	$ 791,926	$ 76,792	$ 76,195

We made our initial acquisition of oil and gas producing and non-producing properties in Argentina in September 2005 for a total purchase price of approximately $7 million. Prior to that time we had no revenues. In June 2006, we acquired Argosy Energy International L.P.'s assets in Colombia for consideration of $37.5 million cash, 870,647 shares of our common stock and overriding and net profit interests in certain assets valued at $1 million. In November 2008, we acquired 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.

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 Part I 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. We are headquartered in Calgary, Alberta, Canada and operate in South America in Colombia, Argentina, Peru, and Brazil.

In September 2005, we acquired our initial oil and gas interests and properties, which were in Argentina. During 2006, we increased our oil and gas interests and property base through further acquisitions in Colombia, Argentina and Peru. We funded acquisitions of our properties in Colombia and Argentina through a series of private placements of our securities that occurred between September 2005 and June 2006.

In 2007, we made a new field discovery, Costayaco, in the Chaza Block of the Putumayo Basin in Colombia.

Effective November 14, 2008, we completed the acquisition of Solana Resources Limited ("Solana"), an international resource company engaged in the acquisition, exploration, development and production of oil and natural gas in Colombia and incorporated in Alberta, Canada. At the date of acquisition, Solana held various working interests in nine blocks in Colombia including a 50% working interest in the Chaza Block, which includes the Costayaco field, and a 35% working interest in the Guayuyaco Block, which includes the Juanambu field.

During the third quarter of 2009, we opened a business development office in Rio de Janeiro, Brazil.

In June 2010, we expanded our land position in the Putumayo Basin and added new frontier exploration acreage in Colombia through successful bids on three blocks in Colombia. In August and October 2010 respectively, we made new Colombian field discoveries in Moqueta in the Chaza Block (Putumayo Basin) and Jilguero in the Garibay Block. Also in August 2010, we finalized a farm-in agreement with Alvorada Petroleo S.A. relating to the on-shore Reconcavo Basin in Brazil, pending regulatory approval from Brazil's Agencia nacional de Petroleo Gas natural e Bioncombustiveis ("ANP"). In Peru in September 2010, we acquired a 20% working interest in three blocks and, in December 2010, we acquired a 60% interest in one block. Both transactions in Peru are subject to government approval.

On January 17, 2011, we announced that we had entered into an Arrangement Agreement to acquire Petrolifera Petroleum Ltd. ("Petrolifera"). Petrolifera is a Canadian based international oil and gas company listed on the Toronto Stock Exchange which owns working interests in 11 exploration and production blocks; three located in Colombia, three in Peru and five in Argentina. The Arrangement Agreement is subject to Petrolifera shareholder and regulatory, stock exchange and court approvals, and is expected to close in March 2011. See "Subsequent Events" below for further details of this transaction.

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.

Financial and Operational Highlights

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
Estimated Proved Oil and Gas Reserves, net of royalties - Millions of Barrels of Oil Equivalent (1) (“Mmboe”) at year end	23.8	6	22.4	15	19.4
Production - Barrels of Oil Equivalent (“boe”) per Day	14,448	14	12,684	249	3,635
Prices Realized - per boe	$70.79	25	$56.73	(33)	$84.78
Revenue and Other Income ($000s)	$374,460	42	$263,716	131	$114,029
Net Income ($000s)	$37,172	167	$13,941	(41)	$23,495
Net Income Per Share – Basic	$0.15	150	$0.06	(68)	$0.19
Net Income Per Share – Diluted	$0.14	180	$0.05	(69)	$0.16
Funds Flow From Operations ($000s) (2)	$203,422	28	$159,531	223	$49,437
Capital Expenditures ($000s)	$177,039	101	$88,124	89	$46,728

	As at December 31,				
	2010	% Change	2009	% Change	2008
Cash & Cash Equivalents ($000s)	$355,428	31	$270,786	53	$176,754
Working Capital (including cash & cash equivalents) ($000s)	$265,835	24	$215,161	62	$132,807
Property, Plant and Equipment ($000s)	$727,024	2	$712,743	(7)	$767,552

(1) Gas volumes are converted to boes at the rate of six thousand cubic feet (“mcf”) of gas per barrel of oil, based on the approximate relative energy content of gas and oil. The conversion ratio for natural gas to oil 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) Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under United States Generally Accepted Accounting Principles (“GAAP”). Management uses this financial measure to analyze operating performance and the income (loss) generated by Gran Tierra’s principal business activities prior to the consideration of how non-cash items affect that income (loss), and believes that this financial measure is also useful supplemental information for investors to analyze operating performance and Gran Tierra’s financial results. Investors should be cautioned that this measure should not be construed as an alternative to net income (loss) or other measures of financial performance as determined in accordance with GAAP. Gran Tierra’s 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 (loss) adjusted for depletion, depreciation, accretion and impairment, deferred taxes, stock based compensation, unrealized loss (gain) on financial instruments

and unrealized foreign exchange losses (gains). A reconciliation from funds flow from operations to net income is as follows:

Funds Flow From Operations - Non-GAAP Measure ($000s)	Year Ended December 31, 2010	2009	2008
Net income	$37,172	$13,941	$23,495
Adjustments to reconcile net income to funds flow from operations			
Depletion, depreciation, accretion and impairment	163,573	135,863	25,737
Deferred taxes	(20,090)	(15,355)	(6,418)
Stock-based compensation	8,025	5,309	2,520
Unrealized (gain) loss on financial instruments	(44)	277	(2,882)
Unrealized foreign exchange loss	14,786	19,496	6,985
Funds flows from operations	$203,422	$159,531	$49,437

Financial Highlights for the Year Ended December 31, 2010

In 2010, production of crude oil (net after royalty and inventory adjustments) averaged 14,325 barrels of oil per day ("BOPD"), an increase of 13% over 2009, due mainly to production from new development wells in the Costayaco field in the Chaza Block in Colombia where Gran Tierra has a 100% working interest. Production of natural gas averaged 123 barrels of oil equivalent per day ("BOEPD") from Colombia.

Revenue and other income increased by 42% from 2009 due to increased production and higher oil prices.

A foreign exchange loss of $16.8 million, of which $14.8 million is an unrealized non-cash foreign exchange loss, was recorded in 2010 primarily due to the translation of a deferred tax liability denominated in Colombian pesos. The devaluation of 6% in the U.S. dollar against the Colombian Peso in 2010 resulted in the foreign exchange loss. This represents a decrease from the foreign exchange loss recorded in 2009, of which $19.5 million was an unrealized non-cash foreign exchange loss related primarily to the same deferred tax liability.

Our net income grew by 167% from the prior year to $37.2 million, representing a basic net income per share of $0.15 compared with $0.06 in 2009.

Oil and gas property expenditures for 2010 were $177.0 million: $105.5 million in Colombia, $33.9 million in Argentina, $23.2 million in Peru, $12.4 million in Brazil, and $2.0 million of general corporate assets. Included in the capital expenditures were thirteen wells of which nine were exploration and four were development.

Our cash position of $355.4 million (excluding restricted cash) at December 31, 2010 increased from $270.8 million at December 31, 2009 as a result of increased cash provided by operating activities, partially offset by capital expenditures.

Funds flow from operations increased 28% to $203.4 million in 2010 from $159.5 million in 2009. The increase was primarily due to increased sales volumes and prices as compared to the prior year, only partially offset by increased operating and general and administrative ("G&A") expenses in 2010.

Working capital (including cash & cash equivalents) was $265.8 million at December 31, 2010, which is a $50.7 million increase from December 31, 2009, due mainly to increased cash as at December 31, 2010 compared to December 31, 2009.

Property, plant and equipment as at December 31, 2010 was $727.0 million, an increase of $14.3 million from December 31, 2009, primarily as a result of a 101% increase in capital additions, partially offset by depletion, depreciation, accretion and impairment ("DD&A").

Operational Highlights for the Year Ended December 31, 2010

Exploration and Development Activities in Colombia

Chaza Block

Costayaco Field Drilling, Water Injection and Workovers

In June 2010, we completed logging operations and initiated production testing of Costayaco–11. Costayaco-11 was tied-in and put on production in early July and will be used as a Caballos and T-sand producer and subsequently as a water-injector to provide pressure maintenance in the T-Sandstone reservoir. In the last half of 2010, a successful workover program enhanced the productivity of the Costayaco field. In September and October 2010, a planned water injection facility was completed and water injection commenced from Costayaco-5 and Costayaco-6 into the T-Sand for reservoir maintenance and maximization of oil recovery. Costayaco-12 and Costayaco-13 drilling commenced in December 2010.

Moqueta Field Exploration and Delineation

In June 2010, we completed initial testing on the Moqueta-1 exploration well in the Chaza Block in Colombia. The Moqueta-2 delineation well was drilled in July 2010 from the existing Moqueta-1 pad. The Moqueta-3 appraisal well was completed and tested in October, 2010 and confirmed oil bearing reservoirs in the Villeta U and T Sandstones and Caballos reservoir sandstones. The Moqueta-4 development well was in progress at December 31, 2010 and testing will be complete in March 2011. Additional seismic was also acquired during the year.

Construction of the Moqueta to Costayaco pipeline is expected to commence in the first quarter of 2011 and first oil production is anticipated in the second quarter of 2011.

Dantayaco Field Exploration

Testing of Dantayaco–1 was completed and the well plugged and abandoned in January 2010.

Pacayaco Field Exploration

Pacayaco-1 commenced drilling in November 2010 and was suspended pending acquisition and interpretation of seismic. The acquisition and interpretation is now complete and either a new well or a sidetrack of the existing well will be drilled late in the second quarter of 2011.

Rio Guineo Exploration

Seismic relating to this lead was acquired during the year.

Garibay Block

Testing of Jilguero–1 in the Garibay Block was completed in October 2010 and long-term production testing began in January 2011.

Rio Magdalena Block

Popa-3, an appraisal well in the Rio Magdalena Block, has been drilled and logged and gas bearing reservoirs identified. The well has been cased and suspended pending further evaluation.

Piedmonte Norte and Sur Blocks

Drilling preparations for Taruka-1, an exploration well in the Piedemonte Sur Block, began in late December 2010. Drilling began in January 2011 and the well was plugged and abandoned in February 2011.

Seismic was acquired in both the Piedmonte Norte and Piedmonte Sur blocks during the year.

New Colombian Exploration and Exploitation Contracts

In June 2010, we were awarded three blocks, Putumayo-10, Cauca-6, and Cauca-7, in the Colombia Bid Round administered by Colombia’s ANH. Bid contracts are expected to be finalized by March, 2011. We also completed and received government approval for a farm-in on Putumayo-1 Block.

Argentina Development and Exploration

In July 2010, re-entry and sidetrack operations began on the GTE.St.VMor-2001 well in Valle Morado and, in February 2011, these operations were suspended and the wellbore will be abandoned due to a number of operational challenges encountered. Gran Tierra Energy continues to review alternatives associated with the field development.

We acquired seismic in the Santa Victoria Block and have received a 90 day extension of the exploration period to March 29, 2011, to determine whether to proceed into the next phase of the contract.

Peru Exploration

Block 128

We received Environmental Impact Assessment approvals for seismic and drilling operations on Block 128 during 2010. We acquired seismic during 2010 and began drilling an exploration well in February 2011. Also in February 2011, we relinquished 20% of this Block.

Block 122

We received EIA approvals for seismic and drilling operations on Block 122 during 2010. Seismic acquisition was ongoing at December 31, 2010 and an exploration well is planned for the third quarter of 2011.

Blocks 123, 124, and 129

In September 2010, we acquired a 20% working interest in Block 123, Block 124, and Block 129, which is subject to government approval. These three blocks have a total area of approximately 6.7 million gross acres.

Block 95

In December 2010, we acquired a 60% working interest and the operatorship of Block 95, which is subject to government approval. Block 95 has a total area of 1.3 million gross acres.

Brazil Exploration

On August 29, 2010, we entered into an agreement with Alvorada Petroleo S.A. whereby we will fulfill certain commitments, including the drilling of two wells in 2011, and earn a 70 % working interest in four Blocks in the on-shore Reconcavo Basin, Brazil. The transaction is subject to government approval.

Consolidated Results of Operations (1)

	Year Ended December 31,				
Consolidated Results of Operations (Thousands of U.S. Dollars)	2010	% Change	2009	% Change	2008
Oil and natural gas sales	$ 373,286	42	$ 262,629	133	$ 112,805
Interest	1,174	8	1,087	(11)	1,224
	374,460	42	263,716	131	114,029
Operating expenses	59,446	46	40,784	112	19,218
Depletion, depreciation, accretion and impairment	163,573	20	135,863	428	25,737
General and administrative expenses	40,241	40	28,787	55	18,593
Foreign exchange loss	16,838	(15)	19,797	218	6,235
Other	(44)	123	190	(198)	(193)
	280,054	24	225,421	224	69,590
Income before income taxes	94,406	147	38,295	(14)	44,439
Income tax expense	(57,234)	135	(24,354)	16	(20,944)
Net income	$ 37,172	167	$ 13,941	(41)	$ 23,495
Production, Net of Royalties					
Oil and NGL's ("bbl") (2)	5,228,554	13	4,621,546	248	1,328,145
Natural gas ("mcf") (2)	268,776	448	49,028	237	14,559
Total production ("boe") (2) (3)	5,273,350	14	4,629,717	248	1,330,572
Average Prices					
Oil and NGL's ("per bbl")	$ 71.19	25	$ 56.79	(33)	$ 84.89
Natural gas ("per mcf")	$ 3.90	(1)	$ 3.93	(20)	$ 4.93
Consolidated Results of Operations ("per boe")					
Oil and natural gas sales	$ 70.79	25	$ 56.73	(33)	$ 84.78
Interest	0.22	(4)	0.23	(75)	0.92
	71.01	25	56.96	(34)	85.70
Operating expenses	11.27	28	8.81	(39)	14.44
Depletion, depreciation, accretion and impairment	31.02	6	29.35	52	19.34
General and administrative expenses	7.63	23	6.22	(55)	13.97
Foreign exchange loss	3.19	(25)	4.28	(9)	4.69
Other	(0.01)	125	0.04	(127)	(0.15)
	53.10	9	48.70	(7)	52.29

Income before income taxes	17.91	117	8.26	(75)	33.41
Income tax expenses	(10.85)	106	(5.26)	(67)	(15.74)
Net income	$ 7.06	135	$ 3.00	83	$ 17.67

(1) Consolidated results of operations include the operations of Solana subsequent to our acquisition of Solana on November 14, 2008.
(2) Gas volumes are converted to boes at the rate of six thousand cubic feet 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.
(3) Production represents production volumes adjusted for inventory changes.

Consolidated Results of Operations for the Year Ended December 31, 2010 Compared to 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 to $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 general and administrative 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 crude oil production combined with a 25% improvement in crude oil prices.

Crude oil and NGL production, net after royalties, in 2010 increased to 5.2 million barrels compared to 4.6 million barrels in 2009, due to increased production from our Colombia operations. Average realized crude oil prices for 2010 increased to $71.19 per barrel from $56.79 per barrel in 2009, reflecting higher West Texas Intermediate ("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 to only 328,000 BOE's in 2009. Since our production volumes are reported net after royalties 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, will not be readily comparable. For instance, the increase in the Costayaco field production will not appear as high in comparison with 2009 as it would appear without the additional royalty volumes deducted. Similarly, the per boe operating and general and administrative costs will 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 expense for 2010 increased to $163.6 million compared to $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 to 2009. DD&A expense in 2010 included a $23.6 million ceiling test impairment for our Argentina cost center, including $17.9 million relating to the abandonment of the GTE.St.VMor-2001 sidetrack operations, as compared to a $1.9 million charge in 2009. On a boe basis, DD&A in 2010 was $31.02 compared to $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 was 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 to $6.22 per boe for 2009. The increase in general and administrative costs 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 to $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.

Consolidated Results of Operations for the Year Ended December 31, 2009 Compared to the Results for the Year Ended December 31, 2008

As a result of the Solana acquisition, we increased our working interest to 100% in the Costayaco field and 70% in the Juanambu field, in Colombia, which resulted in increased production, revenue, operating costs, and DD&A in 2009.

Net income of $13.9 million, or $0.06 per share basic and $0.05 per share diluted, was recorded in 2009 compared to $23.5 million, or $0.19 per share basic and $0.16 per share diluted, in 2008. A foreign exchange loss of $19.8 million, of which $19.5 million is an unrealized non-cash foreign exchange loss, an increase of $110.1 million in DD&A to $135.9 million, higher operating and general and administrative expenses, and increased income tax expense, more than offset the higher oil revenues in 2009.

Revenue and interest increased 131% to $263.7 million in 2009 compared to $114.0 million in 2008. This was due to an increase of 248% in crude oil production partially offset by a 33% decrease in crude oil prices.

Crude oil and NGL production, net after royalties, in 2009 increased to 4.6 million barrels compared to 1.3 million barrels in 2008, due mainly to increased production from our Colombia operations. Average realized crude oil prices for 2009 decreased to $56.79 per barrel from $84.89 per barrel in 2008, reflecting lower WTI oil prices.

Operating expenses for 2009 amounted to $40.8 million, a 112% increase from the prior year. The increase in operating expenses is due to expanded operations and increased production levels in Colombia. However, operating expenses on a boe basis in 2009 were $8.81 per boe, a 39% decline from 2008 reflecting a reduction in fixed costs per barrel due to production increases at Costayaco.

DD&A expense for 2009 increased to $135.9 million compared to $25.7 million in 2008. Increased production levels, as well as amortization expense of $102.5 million in 2009 ($6.9 million in 2008) related to the fair value of property, plant and equipment recorded on the acquisition of Solana, accounted for the increases. On a boe basis, DD&A in 2009 was $29.35 compared to $19.34 for 2008. This 52% increase was primarily due to the significant additions to the proved depletable cost base resulting from the Solana acquisition partially offset by higher proved reserves in Colombia. DD&A for 2009 included a $1.9 million ceiling test impairment loss in our Argentina cost center. This impairment loss resulted from higher estimated future operating costs to produce remaining reserves.

G&A expenses of $28.8 million for 2009 were 55% higher than 2008 due to increased employee related costs reflecting the expanded operations in Colombia. However, due to higher production in 2009, G&A expenses per boe decreased 55% to $6.22 per boe compared to $13.97 per boe for 2008.

The foreign exchange loss of $19.8 million for 2009, of which $19.5 million is an unrealized non-cash foreign exchange loss, compares to $6.2 million recorded in 2008. These losses primarily represent foreign exchange losses that originate in Colombia from the translation of a deferred tax liability recorded on the purchase of Solana.

Income tax expense for 2009 amounted to $24.4 million compared to $20.9 million recorded in 2008. This represents an increase of 16% in annual income tax expense, primarily due to an increase in foreign currency translation losses that are neither taxable nor deductible for tax purposes in each of the respective jurisdictions. The increase in the 2009 effective tax rate to 64% from 47% in 2008 is primarily due to the increase in the valuation allowance associated with increased losses in our U.S., Canadian and Peru business units. The variance from the 35% U.S. statutory rate for 2009 results from an increase in the valuation allowances as described above, and the recapture of enhanced tax depreciation incentive in Colombia, due to a disposal of assets during the year, offset by enhanced tax depreciation taken on oil and gas capital expenditures. The variance from the 35% U.S. statutory rate for 2008 is primarily attributable to recognition of previously unrecognized foreign tax credits, foreign currency translation fluctuations that are not taxable or deductible in the related foreign jurisdictions, and valuation allowances taken on losses incurred in the U.S., Canada, and Peru.

Estimated Oil and Gas Reserves

Estimated proved oil reserves, net of royalties, as of December 31, 2010, were 23.6 million barrels, 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 natural gas liquids reserves, net of royalties, as of December 31, 2010 were 7.4 million barrels and 16.3 million barrels, respectively.

Estimated proved gas reserves, net of royalties, as of December 31, 2010, were 1.2 billion cubic feet ("bcf"), a 37 % decrease from the estimated proved reserves as at December 31, 2009. Estimated probable and possible gas reserves, net of royalties, as of December 31, 2010 were 0.1 bcf and 42.1 bcf, respectively.

Estimated proved oil reserves, net of royalties, as of December 31, 2009, were 22.1 million barrels, a 15% increase from the estimated proved reserves as at December 31, 2008. The increase resulted from our successful development drilling program in Colombia which more than offset 2009 production of oil. Estimated probable and possible oil reserves, net of royalties, as of December 31, 2009, were 5.8 million barrels and 11.5 million barrels, respectively.

Estimated proved gas reserves, net of royalties, as of December 31, 2009, were 1.9 bcf, a 61% increase from the estimated proved reserves as at December 31, 2008. Estimated probable and possible gas reserves, net of royalties, as of December 31, 2009, were 1.7 bcf and 34.5 bcf, respectively.

Segmented Results of Operations

Our operations are carried out in Colombia, Argentina, Peru, and Brazil, and we are headquartered in Calgary, Alberta, Canada. Our reportable segments include Colombia, Argentina and Corporate with the latter including the results of our initial activities in Peru and Brazil. In 2010, Colombia generated 96% of our revenue and other income.

Segmented Results – Colombia (1)

	Year Ended December 31,				
Segmented Results of Operations – Colombia	2010	% Change	2009	% Change	2008
(Thousands of U.S. Dollars)					
Oil and natural gas sales	$359,302	44	$248,834	141	$103,202
Interest	460	(1)	466	(53)	995
	359,762	44	249,300	139	104,197
Operating expenses	50,431	52	33,091	173	12,117
Depletion, depreciation and accretion	133,728	5	127,213	473	22,199
General and administrative expenses	15,216	17	13,011	173	4,769
Foreign exchange loss	17,901	(11)	20,158	204	6,622
	217,276	12	193,473	323	45,707
Segment income before income taxes	$142,486	155	$55,827	(5)	$58,490
Production, Net of Royalties					
Oil and NGL's ("bbl") (2)	4,944,510	15	4,284,230	295	1,085,198
Natural gas ("mcf") (2)	268,776	448	49,028	(237)	14,559
Total production ("boe") (2) (3)	4,989,306	16	4,292,401	295	1,087,625
Average Prices					
Oil and NGL's ("per bbl")	$72.45	25	$58.04	(39)	$95.04
Natural gas ("per mcf")	$3.90	(1)	$3.93	(20)	$4.93
Segmented Results of Operations ("per boe")					
Oil and natural gas sales	$72.01	24	$57.97	(39)	$94.89
Interest	0.09	(18)	0.11	(88)	0.91
	72.10	24	58.08	(39)	95.80
Operating expenses	10.11	31	7.71	(31)	11.14
Depletion, depreciation and accretion	26.80	(10)	29.64	45	20.41
General and administrative expenses	3.05	1	3.03	(31)	4.38
Foreign exchange loss	3.59	(24)	4.70	(23)	6.09
	43.55	(3)	45.08	7	42.02
Segment income before income taxes	$28.55	120	$13.00	(76)	$53.78

(1) Segmented results of operations for Colombia include the operations of Solana subsequent to our acquisition of Solana on November 14, 2008.

(2) Natural gas liquids ("NGL") volumes are converted to boe on a one-on-one basis with oil. Gas volumes are converted to boes 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.

(3) Production represents production volumes adjusted for inventory changes.

Segmented Results of Operations – Colombia for the Year Ended December 31, 2010 Compared to 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 to 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 crude oil and NGLs, net after royalties, increased by 15% to 4.9 million barrels compared to 4.3 million barrels 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 in "Consolidated Results of Operations") reduced the increase in total production from the Costayaco field as compared to the prior year.

Gran Tierra's 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 Ecopetrol operated Trans Andean Pipeline ("OTA") 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 to 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 crude oil prices in 2010 compared to 2009. The average net realized prices for crude oil, which are based on WTI prices, increased by 25% to $72.45 per barrel for the year ended December 31, 2010 compared to 2009. Increased production combined with the increased net realized crude 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, Gran Tierra 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 for Gran Tierra 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 to $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 to 2009 further increased the per boe operating cost amounts from 2009.

For 2010, DD&A expense increased to $133.7 million from $127.2 million in 2009. Increased production levels partially offset by higher crude oil reserve levels and a lower future development cost added to the depletable base, accounted for the increase in DD&A expense. On a per boe basis, the DD&A expense 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 expense 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 to 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. 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. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $104,000 for each one peso decrease in the exchange rate of the Colombian peso to one US dollar at December 31, 2010.

Segmented Results of Operations – Colombia for the Year Ended December 31, 2009 Compared to the Results for the Year Ended December 31, 2008

For the year ended December 31, 2009, income before income taxes from Colombia amounted to $55.8 million compared to income before taxes of $58.5 million recorded in 2008. An increase in production revenue was more than offset by increased expenses including a $13.5 million increase in foreign exchange loss to $20.2 million, of which $19.3 million is an unrealized non-cash foreign exchange loss, primarily due to the translation of deferred taxes. Also, a $105.0 million increase in DD&A, primarily a result of the amortization of the fair value of Solana's property, plant and equipment recorded upon our acquisition of Solana, partially offset the increase in production revenue. Higher operating expenses due to increased Colombian production and increased general and administrative expenses from expanded activities also contributed to a reduction in income before income taxes.

For the year ended December 31, 2009, production of crude oil and NGLs, net after royalties, increased by 295% to 4.3 million barrels compared to 1.1 million barrels in 2008. The incremental production volumes from Solana properties for the year ended December 31, 2009 were 2.2 million barrels of oil, compared to 69,747 barrels of oil subsequent to the acquisition of Solana on November 14, 2008. These production levels are after government royalties ranging from 8% to 22.5% and third party royalties of 2% to 10%.

Gran Tierra's Colombian operating results for the year ended December 31, 2009 are principally impacted by the inclusion of production from three new development wells in the Costayaco field, including Solana's 50% share of production from Costayaco, and Solana's 35% share of production from Juanambu – 1 in the Guayuyaco Block. In 2008, Colombia production included production from Costayaco – 1, 2, 3, 4, 5, and Juanambu – 1 along with production from the Santana Block.

Our production in 2009 and 2008 was impacted by political and economic factors in Colombia. In the second and third quarter of 2009, and the first and second quarter of 2008, sections of the Ecopetrol operated Trans Andean Pipeline were damaged, which temporarily reduced our deliveries to Ecopetrol. On November 24, 2008, we temporarily suspended production operations in the Costayaco and Juanambu oil fields. This was as a result of a declaration of a state of emergency and force majeure by Ecopetrol, due to a general strike in the region where our operations are located. On January 12, 2009, crude oil transportation resumed in southern Colombia as a result of the lifting of the strike at the Orito facilities operated by Ecopetrol.

As a result of these factors, deliveries to Ecopetrol in 2009 were reduced to approximately 3,800 BOPD, net after royalties, for 32 days between July and August 2009, and reduced to approximately 2,200 BOPD, net after royalties, for 14 days in June, and we were shut in for the first 10 days of January. During the first quarter of 2008, deliveries to Ecopetrol were reduced to approximately 1,900 BOPD, net after royalties, for 18 days and in the second quarter of 2008 deliveries were reduced to approximately 2,300 BOPD, net after royalties, for 14 days.

Revenue and interest were negatively impacted by a decline in net realized crude oil prices in 2009 compared to 2008. The average net realized prices for crude oil, which are based on WTI prices, decreased by 39% to $58.04 per barrel for the year ended December 31, 2009 compared to 2008. However, substantially increased production resulted in our revenue and interest from Colombia for the year ended December 31, 2009 increasing by 139% to $249.3 million from 2008.

As a result of achieving gross field production of five million barrels in our Costayaco field during the month of September 2009, Gran Tierra is now subject to an additional government royalty payable. This royalty is calculated on 30% of the field production revenue over an inflation adjusted trigger point. That trigger point for Gran Tierra was $30.22 for 2009. 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 19,000 BOPD and $70 WTI per barrel are approximately 24.8%, including the additional government royalty of approximately 17.0%. The National Hydrocarbons Agency sliding scale royalty at 19,000 BOPD is approximately 9.4% and this royalty is deductible prior to calculating the additional government royalty.

Operating expenses for the year ended December 31, 2009 increased to $33.1 million from $12.1 million in 2008. The increased operating expenses resulted from the increase in production and the inclusion of the Solana operations acquired on November 14, 2008. However, on a per boe basis, operating expenses for 2009 declined to $7.71 compared to $11.14 incurred in 2008, reflecting the reduction of fixed operating costs per barrel as total production increased.

For 2009, DD&A expense increased to $127.2 million from $22.2 million in 2008. Increased production levels coupled with a higher depletable cost base resulting from the Solana acquisition, partially offset by higher crude oil reserve levels, accounted for the increase in DD&A expense. The incremental DD&A expense recorded as a result of the Solana acquisition was $102.5 million for the year ended December 31, 2009 compared to $6.9 million recorded in 2008. On a per boe basis, the DD&A expense in Colombia increased by 45% to $29.64 for 2009, compared with $20.41 for 2008, due to the higher depletable cost base reflecting the Solana properties recorded at fair value upon acquisition, partially offset by increased proved reserves.

Higher G&A expenses incurred to manage the increased level of development and operating activities, the Solana acquired properties, and increased stock-based compensation expense resulted in G&A expense increasing to $13.0 million for the year ended December 31, 2009 from $4.8 million incurred in 2008. On a per boe basis, G&A expense in 2009 decreased by 31% to $3.03 from $4.38 in 2008, due to higher production.

The foreign exchange loss of $20.2 million for the year ended December 31, 2009 includes an unrealized non-cash foreign exchange loss of $19.3 million which resulted primarily from the translation of a deferred tax liability denominated in Colombian Pesos recognized on the purchase of Solana. A strengthening in the Colombian peso against the U.S. dollar results in foreign exchange losses, estimated at $104,000 for each one peso decrease in the exchange rate of the Colombian peso to one US dollar.

Capital Program - Colombia

Gran Tierra's focus for 2010 was to continue with the development of the Costayaco field to increase our production and reserves, in addition to undertaking additional oil exploration efforts to further define the potential of our acreage in Colombia. In support of this strategy, our capital expenditures in Colombia amounted to $105.5 million for the year ended December 31, 2010.

Segmented Capital Expenditures – Colombia Block and Activity (Millions of U.S. Dollars)			Year Ended December 31, 2010
Chaza	Costayaco facilities and site preparation and drilling for Costayaco -11, -12, -13, Moqueta -1, -2, -3, -4, Pacayaco-1, Canangucho -1	$	75.0
Rio Magdalena	Popa-3 drilling		1.6
Guayuyaco	Juanambu -2 drilling and facilities		6.3
Garibay	Completion of 3D seismic program and Jilguero -1 drilling		1.0
Rumiyaco	Commencement of 3D seismic		5.1
Piedemonte Sur	Taruka -1 well		5.9
Azar	2D and 3D seismic programs		1.5
Piedemonte Norte	Commencement of 3D seismic		2.4
Magangue	Guepaje facilities		0.6
Capitalized G&A, $5.0 property acquisition and other			6.1
Segmented Capital Expenditures – Colombia		$	105.5

For comparison, for the year ended December 31, 2009, we spent $81.4 million on capital projects.

Segmented Capital Expenditures – Colombia Block and Activity (Millions of U.S. Dollars)			Year Ended December 31, 2009
Chaza	Drilled and tested Costayaco -6, -7, -8, -9, commenced drilling of Costayaco -10, drilled Dantayaco-1, commenced 2D seismic program, installed facilities and equipment	$	53.6
Rio Magdalena			3.4

	Completion and long term testing of Popa-2 well and 3D 75 kilometers ("km") seismic program		
Guachiria	Completed acquisition of 115 square kilometers ("km2") of 3D seismic		1.0
Guachiria Norte	Drilling of the Puinaves -2 exploration well, which was dry		5.8
Guachiria Sur	Completed acquisition of 115 km2 of 3D seismic		3.7
Garibay	Completed acquisition of 110 km2 of 3D seismic		3.4
Azar	Commencement of 2D and 3D seismic programs		2.3
Guayayaco	Juanambu production separator		2.0
Leasehold improvements			1.8
Capitalized G&A and other			4.4
Segmented Capital Expenditures – Colombia		$	81.4

For comparison, for the year ended December 31, 2008, we spent $31.7 million on capital projects. Included in this amount was $6.8 million in capital expenditures related to the Solana properties subsequent to the acquisition.

Segmented Capital Expenditures - Colombia Block and Activity (Millions of U.S. Dollars)		Year Ended December 31, 2008	
Chaza	Drilled and tested Costayaco -2, -3, -4, -5, commenced drilling of Costayaco -6, and facilities and equipment	$	17.8
Costayaco pipeline	15 km 8-inch pipeline to connect Costayaco field to existing pipeline infrastructure		4.0
Azar	Acquired 40 km2 of 3D seismic and we performed one well re-entry on the Palmera 1 well, encountering oil		1.3
Guachiria	Drilling Los Aceites-1 and Primavera-1		1.1
Guachiria Norte	Drilled an exploration well, Zafiro-1, in November 2008, which was dry		3.4
Capitalized G&A and other			4.1
Segmented Capital Expenditures – Colombia		$	31.7

In October 2010, we sold a 3% overriding interest in Jilguero-1 and a 1% overriding interest in the Garibay Block for $6.4 million.

Due to the high cost to transport oil produced from the Guachiria Blocks in the Llanos Basin in Colombia, production was shut in February 2009. In April 2009, Gran Tierra signed an asset purchase and sale agreement with a third party for Gran Tierra's interests in the Guachiria Norte, Guachiria, and Guachiria Sur blocks. Principal terms included consideration of $7.0 million from the third party, comprising an initial cash payment of $4.0 million at closing, followed by 15 monthly installments of $200,000 each beginning June 1, 2009 and extending through August 3, 2010, less settlement of outstanding amounts. The sale closed on April 16, 2009 and Gran Tierra recorded net proceeds of $6.3 million. 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 our costs for previously acquired seismic data.

Segmented Results – Argentina

	Year Ended December 31,				
Segmented Results of Operations - Argentina (Thousands of U.S. Dollars)	2010	% Change	2009	% Change	2008
Oil and natural gas sales	$13,984	1	$13,795	44	$9,603
Interest	26	(80)	127	452	23
	14,010	1	13,922	45	9,626
Operating expenses	8,808	17	7,537	7	7,027
Depletion, depreciation, accretion and impairment	29,416	253	8,339	146	3,390
General and administrative expenses	2,868	24	2,318	13	2,055
Foreign exchange loss (gain)	165	493	(42)	(114)	311
	41,257	127	18,152	42	12,783

Segment loss before income taxes	$(27,247)	544	$(4,230)	34	$(3,157)
Production, Net of Royalties					
Oil and NGL's ("bbl") (1) (2)	284,044	(16)	337,316	39	242,947
Average Prices					
Oil and NGL's ("per bbl")	$49.23	20	$40.90	3	$39.53
Segmented Results of Operations ("per boe")					
Oil and NGL sales	$49.23	20	$40.90	3	$39.53
Interest	0.09	(76)	0.38	322	0.09
	49.32	19	41.28	4	39.62
Operating expenses	31.01	39	22.34	(23)	28.92
Depletion, depreciation, accretion and impairment	103.56	319	24.72	77	13.95
General and administrative expenses	10.10	47	6.87	(19)	8.46
Foreign exchange loss (gain)	0.58	583	(0.12)	(110)	1.28
	145.25	170	53.81	2	52.61
Segment loss before income taxes	$(95.93)	666	$(12.53)	(4)	$(12.99)

(1) NGL volumes are converted to boe on a one-to-one basis with oil.

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

Segmented Results of Operations – Argentina for the Year Ended December 31, 2010 Compared to the Results for the Years Ended December 31, 2009 and December 31, 2008

For the 2010 fiscal year, the pre-tax loss from Argentina was $27.3 million compared to pre-tax losses of $4.2 million and $3.2 million recorded in fiscal years 2009 and 2008, respectively, due to lower production levels and increased operating and G&A expenses as well as DD&A in 2010, 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. The impairment loss in 2010 included $17.9 million relating to the abandonment of the sidetrack operations at the GTE.St.VMor-2001 well. The remaining $5.2 million impairment loss resulted from an increase in estimated future operating costs to produce remaining proved reserves and a reduction in reserves. 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 284,044 barrels in 2010 compared to 337,316 barrels in 2009 and 242,947 barrels in 2008. The decrease resulted from general production declines. The increase in production levels in 2009 in comparison with 2008 resulted from the successful completion and testing of the Proa-1 exploration well in the Surubi Block in the third quarter of 2008 with sales commencing in the fourth quarter of that year.

Due to the local regulatory regimes, the price we currently receive for production from our blocks is approximately $53.50 per barrel. Furthermore, currently all oil and gas producers in Argentina are operating without sales contracts. A new withholding tax regime was introduced in Argentina with Resolution 394/2007 . Producers and refiners of oil in Argentina have been unable to determine an agreed sales price for oil deliveries to refineries since the mentioned resolution; however, we are continuing sales of our oil under monthly agreements with Refinor S.A. We are working with other oil and gas producers in the area, as well as Refinor S.A., to lobby the federal government for change.

Capital Program - Argentina

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 the acquisition of seismic.

Capital expenditures for the year ended December 31, 2008, amounted to $11.7 million and included drilling of the Proa-1 discovery well on the Surubi Block for a net cost of $9.5 million. Proa-1 commenced production in September 2008. The provincial oil company REFSA farmed-in to the block for a 15% working interest, and are paying their share of well costs from their share of production from Proa-1. In 2008, other costs of $1.2 million were incurred primarily on capitalized well workovers, well re-entries, seismic acquisition, and equipment upgrades.

Segmented Results – Corporate

	Year Ended December 31,				
	2010	% Change	2009	% Change	2008
Segmented Results of Operations - Corporate (Thousands of U.S. Dollars)					
Interest	$688	39	$494	140	$206
Operating expenses	207	33	156	111	74
Depletion, depreciation and accretion	429	38	311	110	148
General and administrative expenses	22,157	65	13,458	14	11,769
Derivative financial instruments (gain) loss	(44)	123	190	(198)	(193)
Foreign exchange gain	(1,228)	285	(319)	(54)	(698)
	21,521	56	13,796	24	11,100
Segment loss before income taxes	$(20,833)	57	$(13,302)	22	$(10,894)

Segmented Results of Operations - Corporate

In addition to the expenditures associated with the maintenance of Gran Tierra's headquarters in Calgary, Alberta, Canada, cost of compliance and reporting under the securities regulations, business development and technical oversight and support for our operations, the results of the Corporate Segment include the results of our initial operations in Peru and Brazil.

G&A Expenses

Increased staffing levels to support business development activities and expanded operations in Peru and Brazil as well as higher stock based compensation expense due to increased stock option grants were the contributing factors to the three-year increase in Corporate G&A.

Derivative Financial Instruments (Gain) Loss

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2010	2009	2008
Realized financial derivative (gain) loss	$-	$(87)	$2,689
Unrealized financial derivative (gain) loss	(44)	277	(2,882)
Derivative financial instruments (gain) loss	$(44)	$190	$(193)

	As at December 31,	
Assets (Liabilities)	2010	2009

Derivative financial instruments	$ -	$ (44)

In accordance with the terms of the credit facility with Standard Bank Plc, in February of 2007 we entered into a costless collar financial derivative contract for crude oil based on WTI price, with a floor of $48.00 and a ceiling of $80.00, for a three year period, for 400 barrels per day from March 2007 to December 2007, 300 barrels per day from January 2008 to December 2008, and 200 barrels per day from January 2009 to February 2010. We had no derivative contracts outstanding at December 31, 2010.

For the year ended December 31, 2010, we recorded a gain of $44,000. This compares to a loss of $0.2 million and gain of a $0.2 million, for the years ended December 31, 2009, and 2008, respectively. These gains and losses are based on the effects of changing WTI crude oil price, and forward price curves used to fair value the costless collar at the respective year ends.

Foreign Exchange Loss (Gain)

The foreign exchange loss (gain) results from the translation of foreign currency denominated transactions to U.S. Dollars.

Capital Program – Corporate

The capital expenditures for the Corporate Segment during the year ended December 31, 2010 were $37.6 million. These expenditures included $21.2 for seismic acquisition in Peru on our exploration blocks 122 and 128, a $2.0 million deposit on the farm-in of Block 95 in Peru, an $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.

The capital expenditures for the Corporate Segment during the year ended December 31, 2009 were $2.2 million. These expenditures included $1.8 million for Peru on our exploration blocks 122 and 128 for drilling feasibility and geological studies.

The 2008 capital expenditures of $3.3 million for the Corporate Segment included expenditures of $2.8 million for Peru on our exploration blocks 122 and 128. Acquisition of technical data through aeromagnetic-gravity studies began in 2007, and was completed in the first half of 2008, with a total of 20,000 kilometers of data acquired over both blocks. In 2008, we started Environmental Impact Assessments and the community consultation process on both blocks. These projects were completed in 2009, along with drilling feasibility and geological studies.

Fourth Quarter Results

The following table provides an analysis of quarterly financial information (in thousands of dollars except production, per share and per BOE amounts) for the three months ended December 31, 2010 compared to the same period in 2009:

	Three Months Ended December 31,	
Selected Quarterly Financial Information	2010	2009
Production - barrels of oil equivalent per day	15,928	14,714
Per BOE prices realized	$ 76.79	$ 70.93
Revenue and other income	$ 112,667	$ 96,286
Expenses	72,244	53,106
Income before income tax	40,423	43,180
Income tax expense	27,305	12,355
Net income	13,118	30,825
Basic earnings per share	$ 0.05	$ 0.13
Diluted earnings per share	$ 0.04	$ 0.12

The fourth quarter 2010 net income was positively impacted by the increase in production and higher crude oil prices, partially offset by the increase in expenses related to expanded operations.

Revenue and other income for the fourth quarter of 2010 amounted to $112.7 million, an increase of 17% from the same quarter last year. Higher production levels and improved crude oil prices contributed to this significant increase. Production of crude oil and natural gas increased by 8% to 15,928 BOEPD from 14,714 BOEPD in the last quarter of 2009. The positive effect of this increase in production was complemented by the increase in crude oil prices. Average prices per boe increased by 8% to $76.79 in the fourth quarter of 2010 from $70.93 realized in the same quarter last year.

Operating expenses increased $4.7 million in the fourth quarter of 2010 as compared to the fourth quarter of 2009 due primarily to the workover program in Costayaco and increased transportation costs related to higher production and pipeline maintenance in 2010. G&A expenses increased $2.8 million in the fourth quarter of 2010 as compared to the fourth quarter of 2009 due to increased activity. DD&A expense between the two quarters increased $15.9 million to $56.3 million in 2010 mainly due to the Argentina cost center ceiling test impairment of which $17.9 million related to the abandonment of the GTE.St.VMor-2001 sidetrack operations offset by a higher reserve base in 2010. The comparative results between the two quarters were also affected by a foreign exchange gain of $16.9 million recorded in the three months ended December 31, 2010 compared to a foreign exchange gain of $12.6 million recorded in the same quarter of the previous year, as previously discussed.

Liquidity and Capital Resources

At December 31, 2010, we had cash and cash equivalents of $355.4 million compared to $270.8 million at December 31, 2009, and $176.8 million at December 31, 2008. We believe that our cash position, together with positive cash flow from operations and no debt, will provide us with sufficient liquidity to meet our strategic objectives and fund our planned capital program for at least the next twelve months. In accordance with our investment policy, cash balances are invested only in United States 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.

Gran Tierra believes that it has sufficient available cash and cash flow from operations to cover its expected funding needs on both a short-term and long-term basis. If the need were to arise, Gran Tierra believes that it could access short-term debt markets, to fund its short-term requirements and to ensure near-term liquidity. Gran Tierra regularly monitors the credit and financial markets and, in the future, may take advantage of what it believes are favorable market conditions to issue long-term debt to further improve its liquidity and capital resources. Gran Tierra's long-term financing strategy is to maintain continuous access to the debt markets to accommodate its long term growth strategy.

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 our two 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 USD LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.50% per annum is charged on the unutilized balance of the committed borrowing base and is included in general and administrative expense. Under the terms of the facility, we are required to maintain and were in compliance with certain financial and operating covenants. As at December 31, 2010, we had not drawn down any amounts under this facility.

Cash Flows

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 from financing activities of $24.7 million more than offset net cash outflows for investing activities of $143.9 million.

Net cash provided by operating activities in 2010 was positively affected by the increases in crude oil production and realized oil price over the prior year. The positive affect of the higher production and pricing levels was partially offset by increases in operating and G&A expenses and cash taxes as well as an increase in accounts receivable associated with the higher oil revenue and a reduction of accounts payable related to operating activities.

As previously discussed, the oil and gas property expenditures in 2010 primarily related to continued development of our Costayaco field in Colombia and the identification of new exploration prospects in all business units resulting in the increase in cash used for investing activities. Cash provided by financing activities in 2010 related to the exercise of outstanding warrants and employee stock options.

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 from financing activities of $4.9 million more than offset cash outflows for investing activities of $76.4 million.

Net cash provided by operating activities in 2009 was affected by the significant increase in crude oil production partially offset by the decrease in oil prices and increase in receivables related to oil sales. The acquisition of Solana along with the additional production from three new development wells in Colombia contributed to the increased production. This increased oil revenue from higher production volumes and a higher fourth quarter 2009 average oil price received, as compared to the same quarter of the prior year, resulted in our accounts receivable increasing from the 2008 year end. This was more than offset by an increase in our accounts payable and accrued liabilities associated with operating activities at year end. In addition, in December 2008, our operations in Colombia were significantly restricted due to a general strike which reduced our year end accounts receivable. The 2009 oil and gas property expenditures primarily related to continued development of our Costayaco field in Colombia and the identification fo new exploration prospects in all business units resulting in the increase in cash used for investing activities. Cash provided by financing activities related to the exercise of outstanding warrants and employee stock options.

For the year ended December 31, 2008, our cash and cash equivalents increased by $158.6 million due to positive cash inflows from operations of $109.7 million, from investing activities of $27.1 million and from financing activities of $21.7 million. Net cash provided by operating activities was positively affected by the significant increases in crude oil production and prices as well as collection of receivables obtained as part of the Solana acquisition and an increase in current income taxes payable related to Gran Tierra's taxable position in Colombia. Cash inflows from investing activities included $81.9 million assumed on the purchase of Solana, net of acquisition costs, offset by $55.2 million in capital expenditures related to our exploration and development and other oilfield related activities net of the change in non-cash working capital. Cash inflows from financing activities of $21.7 million related to the proceeds from the exercise of warrants and stock options.

As previously discussed, the increase in oil and gas property expenditures primarily relate to continued development of our Costayaco field in Colombia and the identification of new exploration prospects in all business units resulting in the increase in cash used for investing activities. Cash provided by financing activities relates to the exercise of outstanding warrants and employee stock options.

Off-Balance Sheet Arrangements

As at December 31, 2010, 2009 and 2008 we had no off-balance sheet arrangements.

Contractual Obligations

Gran Tierra holds three categories of operating leases, namely office, vehicle and housing. We pay monthly costs of $0.2 million for office leases, $11,000 for vehicle leases and $5,000 for certain employee accommodation leases in Colombia, Argentina and Peru.

Future lease payments and other contractual obligations at December 31, 2010 are as follows:

		As at December 31, 2010 Payments Due in Period			
Contractual Obligations (Thousands of U.S. Dollars)	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
Operating leases	$5,444	$2,476	$2,068	$900	$ -
Software and telecommunication	1,456	1,137	319	-	-
Drilling, completion, facility construction and oil transportation services	71,412	62,754	8,658	-	-
Consulting	393	393	-	-	-
Total	$78,705	$66,760	$11,045	$900	$ -

Contractual commitments have increased $45.4 million from December 31, 2010 as a result of increased operating leases primarily due to entering into more third party facility construction, oil transportation and drilling rig commitment contracts ($46.4 million), in Colombia, Argentina, and Peru.

The acquisition of Petrolifera, announced January 2011 and expected to close in March 2011, will be achieved through a share exchange; however, we expect to retire Petrolifera's bank debt after closing, which would result in a cash outflow of approximately $60 million.

Related Party Transactions

On August 3, 2010, Gran Tierra entered into a contract related to the drilling program in Peru with a company for which one of Gran Tierra's directors is a shareholder and director. At December 31, 2010, $0.8 million has been capitalized and accrued in relation to this contract, the terms of which, are consistent with market conditions.

In connection with the Solana acquisition, we acquired additional office space of 4,441 square feet used by Solana as its headquarters in Calgary. On February 1, 2009, we entered into a sublease for that office space with a company, of which one of Gran Tierra's directors is a shareholder and director. The term of the sublease runs from February 1, 2009 to August 31, 2011 and the sublease payment is $7,800 per month plus approximately $4,000 for operating and other expenses. The terms of the sublease were consistent with market conditions in the Calgary real estate market.

Subsequent Events

On January 17, 2011, we entered into an Agreement to acquire all the issued and outstanding shares and warrants of Petrolifera Petroleum Limited (“Petrolifera”). Petrolifera is a Canadian based international oil and gas company that trades on the Toronto Stock Exchange and has oil and gas assets in Argentina, Colombia, and Peru. Under the terms of the Agreement, Petrolifera shareholders will receive 0.1241 of a share of Gran Tierra Energy, for every Petrolifera share held. In addition, we will issue replacement warrants for the outstanding warrants to purchase Petrolifera common shares, in the amount of 0.1241 of a Gran Tierra warrant for each Petrolifera warrant. A total of approximately 19 million of Gran Tierra’s shares are expected to be issued in the transaction, which represents approximately an 8% increase in shares outstanding. Total consideration for the transaction will be approximately $195 million, including the assumption of Petrolifera’s debt, working capital and investments as of September 30, 2010. The Agreement is subject to regulatory, court, stock exchange, and Petrolifera securityholder approvals and is scheduled to close in March 2011.

On January 12, 2011, we entered into an agreement to sublease office space to a company for 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, at $4,444 per month, the terms are consistent with market conditions in the Calgary, Alberta, Canada real estate market.

Outlook

Business Environment

Our revenues have been positively impacted by the increase in crude oil prices from the prior year. Crude oil prices are volatile and unpredictable and are influenced by concerns about financial markets and the impact of the downturn in the worldwide economy on oil demand growth. Further, following the acquisition of Petrolifera through a share exchange, announced January 2011 and expected to close in March 2011, we expect to retire Petrolifera’s bank debt, which will reduce our cash by approximately $60 million. However, based on projected production, prices, costs and our current liquidity position, we believe that our current operations and 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.

Our future growth and acquisitions may depend on our ability to raise additional funds through equity and debt markets. Determination of the borrowing base under our credit facility will most likely be dependent on our success in maintaining or increasing oil and gas reserves and on future oil prices. 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 stockholders, 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 pledging of some or all of our assets. Volatility in the credit markets may increase costs associated with renewing or issuing debt, or affect our, or third parties we seek to do business with, ability to access those markets.

2011 Work Program and Capital Expenditure Program

In December 2010, prior to the finalization and announcement of the Petrolifera acquisition, we announced the details of Gran Tierra’s 2011 work program. Gran Tierra’s 2011 work program is intended to create both growth and value in our existing assets through increasing our reserves and production from exploration financed by cash flow, 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 acquisition opportunities. However, actual capital expenditures may vary significantly from our 2011 work program if unexpected events or circumstances occur, such as new opportunities present themselves, or anticipated opportunities do not come to fruition, which may therefore either increase or decrease the amount of capital expenditures we incur in 2011. Capital commitments and other exploration and development opportunities arising from the Petrolifera acquisition were not contemplated in the original capital program and may have a significant impact on the amount and allocation of capital expenditures for each country. The effect of the acquisition on the capital program will be assessed on an ongoing basis.

Excluding potential exploration success, production in 2011 is expected to range between 16,000 and 18,000 BOEPD net after royalty.

Gran Tierra has planned a 2011 capital spending program of $299 million for exploration and development activities in Colombia, Peru, Argentina and Brazil. Planned capital expenditures are $148 million in Colombia, $56 million in Peru, $39 million in Argentina, and $55 million in Brazil.

We expect that our committed and discretionary 2011 capital program can be funded from cash flow from operations and cash on hand. The details of the capital programs planned for each country do not contemplate any effect of the Petrolifera acquisition and the portfolio of prospects and commitments that the acquisition includes. The following outlook represents the capital program based upon the current portfolio of Gran Tierra properties.

Outlook – Colombia

The 2011 capital program in Colombia is $148 million. Facility construction associated with ongoing development of the Moqueta field and further facility work at Costayaco is expected to be $30 million. $53 million is budgeted for seismic and $65 million for exploration and development drilling. The drilling program includes four gross development wells and a six well exploration program that comprises four gross exploration wells and two stratigraphic test wells.

The 2011 exploration drilling program in Colombia includes 4 exploration wells, 2 stratigraphic test wells and seismic acquisitions including 440 km2 of 3D seismic and 370 km2 of 2D seismic.

In addition to the above exploration activity we plan to spend approximately $30 million on infrastructure, which includes flow lines, gas reinjection facilities, road access construction and full field development planning.

Outlook – Argentina

The 2011 capital program in Argentina is $40 million. Gran Tierra's planned work program for 2011 includes costs related to the re-entry and sidetrack of the GTE.St.VMor-2001 well and related facilities upgrades, as well as the drilling of a development well in Palmar Largo, workovers in El Vinalar, facility construction, and geophysical work. In February 2011, the sidetrack and re-entry operations at the GTE.St.VMor-2001 well were suspended and the well bore will be abandoned while Gran Tierra evaluates other options associated with field development. The capital budget may be revised based on the results of the evaluation.

Outlook - Peru

The 2011 capital program in Peru is $56 million, including $34 million related to drilling exploration wells and an additional $19 million related to seismic.

Gran Tierra began drilling the first exploration well in Block 128 in February 2011 and plans to drill the second exploration well on Block 122 in the third quarter of 2011. 20% of Block 128 was also relinquished in February 2011.

Seismic activity is planned to continue in blocks 123, 124, and 129 with exploration drilling environmental impact assessments to be conducted concurrently in blocks 123 and 129.

Upon approval of assignment of interests to Gran Tierra by Perupetro S.A., Gran Tierra plans to drill one exploration well on Block 95 in the fourth quarter of 2011.

Outlook - Brazil

The 2011 capital program in Brazil is $55 million and includes $17 million budgeted for drilling and completions and the remainder relates to acquisition costs of the working interest ownership as described below.

Upon the anticipated regulatory approval from Brazil's Agencia Nacional de Petroleo, Gas Natural e Biocombustiveis ("ANP"), Gran Tierra will hold a 70% working interest in Blocks REC-T-129, -142, -155, and -224 in the onshore Reconcavo Basin. The first exploration well in Block 129 is planned for the second quarter of 2011 and will be followed by up to three additional exploration wells including two wells on Block 142 and one well on Block 155. Additionally, two appraisal wells on Block 155 are planned to further develop the existing 1-ALV-2-BA well discovery on the Block.

Critical Accounting Policies and Estimates

The preparation of financial statements under generally accepted accounting principles (“GAAP”) in the United States requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The critical accounting policies used by management in the preparation of our consolidated financial statements are those that are important both to the presentation of our financial condition and results of operations and require significant judgments by management with regards to estimates used. We believe that the assumptions, judgments and estimates involved in oil and gas accounting and reserves determination, establishment of fair values of assets and liabilities acquired as part of acquisitions, impairment, asset retirement obligations, goodwill impairment, deferred income taxes, share-based payment arrangements, and warrants have the greatest potential impact on our consolidated financial statements. These areas are key components of our results of operations and are based on complex rules which require us to make judgments and estimates, so we consider these to be our critical accounting estimates. Our critical accounting policies and significant judgments and estimates related to those policies are discussed below.

Actual results could differ from these estimates, however, historically, our assumptions, judgments and estimates relative to our critical accounting estimates have not differed materially from actual results.

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

Oil and Gas Accounting-Reserves Determination

We follow the full cost method of accounting for our investment in oil and natural gas properties, as defined by the U.S. Securities and Exchange Commission ("SEC"), as described in note 2 to our annual consolidated financial statements. Full cost accounting depends on the estimated reserves we believe are recoverable from our oil and gas reserves. The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering and economic data.

To estimate the economically recoverable oil and natural gas reserves and related future net cash flows, we incorporate many factors and assumptions including:

- Expected reservoir characteristics based on geological, geophysical and engineering assessments
- Future production rates based on historical performance and expected future operating and investment activities
- Future commodity prices
- Future oil and gas quality differentials
- Assumed effects of regulation by governmental agencies
- Future development and operating costs

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

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

Our Board of Directors 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.

Reserves estimates are critical to many of our accounting estimates, including:

- Determining whether or not an exploratory well has found economically producible reserves
- Calculating our unit-of-production depletion rates. Proved reserves estimates are used to determine rates that are applied to each unit-of-production in calculating our depletion expense.
- Assessing, when necessary, our oil and gas assets for impairment. Estimated future cash flows are determined using proved reserves.

The critical estimates used to assess impairment, including the impact of changes in reserves estimates, are discussed below:

Oil and Gas Accounting and Impairment

The accounting for and disclosure of oil and gas producing activities requires that we choose between GAAP alternatives. We use the full cost method of accounting for our oil and natural gas operations. Under this method, separate cost centers are maintained for each country in which we incur costs. All costs incurred in the acquisition, exploration and development of properties (including costs of surrendered and abandoned leaseholds, delay lease rentals, dry holes and overhead related to exploration and development activities) are capitalized. The sum of net capitalized costs and estimated future development costs of oil and natural gas properties for each full cost center are depleted using the unit-of-production method. Changes in estimates of proved reserves, future development costs or asset retirement obligations are accounted for prospectively in our depletion calculation.

Investments in unproved properties are not depleted pending the determination of the existence of proved reserves. Unproved properties are assessed periodically to ascertain whether impairment has occurred. Unproved properties, the costs of which are individually significant, are assessed individually by considering the primary lease terms of the properties, the holding period of the properties, and geographic and geologic data obtained relating to the properties. 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. The amount of impairment assessed is added to the costs to be amortized in the appropriate full cost pool.

The acquisition of Solana was accounted for using the purchase method, with Gran Tierra being the acquirer, whereby the Solana assets acquired and liabilities assumed were recorded at their fair values at the acquisition date with the excess of the purchase price over the fair values of the tangible and intangible net assets acquired recorded as goodwill. Calculation of fair values of assets and liabilities, which was done with the assistance of independent advisors, is subject to estimates which include various assumptions including the extent of proved and unproved reserves of the acquired company as well as the future production and development costs and the 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 depreciation, depletion and accretion expense. 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 our price forecast that we used to originally determine fair value.

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 on a country-by-country basis. The ceiling limits these pooled costs to the aggregate of the after-tax, present value, discounted at 10%, of future cash flows attributable to proved reserves, known as the standardized measure, plus the lower of cost or market value of unproved properties less any associated tax effects. Cash flow estimates for our impairment assessments require assumptions about two primary elements — constant prices and reserves. It is difficult to determine and assess the impact of a decrease in our proved reserves on our impairment tests. The relationship between the reserves estimate and the estimated discounted cash flows is complex because of the necessary assumptions that need to be made regarding period end production rates, twelve month unweighted average prices and costs. If these capitalized costs exceed the ceiling, we will record a write-down to the extent of such excess as a non-cash charge to earnings. Any such write-down will reduce earnings in the period of occurrence and result in lower DD&A expense 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. Due to the complexity of the calculation, we are unable to provide a reasonable sensitivity analysis of the impact that a reserves estimate decrease would have on our assessment of impairment. A reduction in oil and natural gas prices and/or estimated quantities of oil and natural gas reserves would reduce the ceiling limitation and could result in a ceiling test write-down.

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. As a result of assessing our oil and gas property impairment for our Argentina cost center, a ceiling test impairment loss of $23.6 million was recorded 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 2008 and found that an impairment write-down of $1.9 million was required in 2009 for our Argentina cost center and that no impairment write-downs were required in 2008 based on our assumptions. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2010 ceiling tests were based on realized crude oil prices of $78.23 and $3.84 per mcf in Colombia and $50.18 for oil production in Argentina.

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 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 asset retirement obligations 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 ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and expected changes in legal, regulatory, environmental and political environments. The asset retirement obligations result in an increase to the carrying cost of our property, plant and equipment. The obligations are accreted with the passage of time. A change in any one of our assumptions could impact our asset retirement obligations, our property, plant and equipment and our net income.

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.

Goodwill

Goodwill represents the excess of purchase price of business combinations over the fair value of net assets acquired and we test for impairment at least annually. The impairment test requires allocating goodwill and certain other assets and liabilities to reporting units. We estimate the fair value of each reporting unit and compare it 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 write down the goodwill to the implied fair value of the goodwill through a charge to expense. Because quoted market prices are not available for our reporting units, we estimate the fair values of the reporting units based upon estimated future cash flows of the reporting unit. The goodwill on our financial statements was a result of the Solana and Argosy acquisitions, and relates entirely to the Colombia reporting segment. This reporting segment is not at risk of failing the “Step 1” goodwill impairment test under Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 350, Intangibles – Goodwill and Others. The calculated fair value of the Colombian business unit was significantly in excess of its book values.

Differences in the our actual future cash flows, operating results, growth rates, capital expenditures, cost of capital and discount rates as compared to 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 based on temporary differences in reported amounts for financial statement and tax purposes. 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.

Share-Based Payment Arrangements

We record share-based payment arrangements in accordance with the ASC 718, Compensation – Stock Compensation, which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors including employee stock options based on estimated fair values.

ASC 718 requires companies to estimate the fair value of share-based payment awards on the date of grant using an option-pricing model. The value of the portion of the award that is ultimately expected to vest is recognized as expense over the requisite service periods in our Consolidated Statement of Operations.

Under ASC 718, share-based compensation expense recognized during the period is based on the value of the portion of share-based payment awards that is ultimately expected to vest during the period. Compensation expense is recognized using the accelerated method. As share-based compensation expense recognized in the Consolidated Statements of Operations is based on awards ultimately expected to vest, it has been reduced for estimated forfeitures. ASC 718 requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

Under ASC 718, we utilize a Black-Scholes option pricing model to measure the fair value of stock options granted to employees. Our determination of fair value of share-based payment awards on the date of grant using an option-pricing model is affected by our stock price as well as assumptions regarding a number of highly complex and subjective variables. These variables include, but are not limited to, our expected stock price volatility over the term of the awards, and actual and projected employee stock option exercise behaviors. We are responsible for determining the assumptions used in estimating the fair value of our share-based payment awards.

Warrants

We follow the fair-value method of accounting for warrants issued to purchase our common stock.

New Accounting Pronouncements

Variable Interest Entities

In June 2009, the FASB issued revised accounting standards to improve financial reporting by enterprises involved with variable interest entities. The standards replace the quantitative-based risks and rewards calculation for determining which enterprise, if any, has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance and: (1) the obligation to absorb losses of the entity; or, (2) the right to receive benefits from the entity. The standards was implemented prospectively on January 1, 2010 and did not materially impact Gran Tierra's consolidated financial position, operating results or cash flows.

Fair Value Measurements

In January 2010, the FASB issued Accounting Standards Update ("ASU"), "Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements". This ASU amends existing disclosure requirements about fair value measurements by adding required disclosures about items transferred into and out of levels 1 and 2 in the fair value hierarchy; adding separate disclosures about purchases, sales, issuances, and settlements relative to level 3 measurements; and clarifying, among other things, the existing fair value disclosures about the level of disaggregation. This is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The implementation of this update on January 1, 2010 did not materially impact Gran Tierra's disclosures.

Subsequent Events

In February 2010, the FASB issued ASU, "Subsequent Events (Topic 855)." The amendments remove the requirements for an SEC filer to disclose a date, in both issued and revised financial statements, through which subsequent events have been reviewed. This ASU was effective upon issuance. The implementation of this update did not materially impact Gran Tierra's disclosures.

Stock Compensation

In April 2010, the FASB issued ASU, "Compensation–Stock Compensation (Topic 718)." The amendments clarify 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 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2010. The implementation of this update is not expected to materially impact Gran Tierra's consolidated financial position, operating results or cash flows.

Receivables

In July 2010, the FASB issued ASU, "Receivables (Topic 310)." The update is intended to provide financial statement users with greater transparency about an entity's allowance for credit losses and the credit quality of its financing receivables. The disclosures as of the end of a reporting period are effective for interim and annual reporting periods ending on or after December 15, 2010. The implementation of this update did not materially impact Gran Tierra's disclosures.

Business Combinations

In December 2010, the FASB issued ASU, "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 date 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 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The implementation of this update is not expected to materially impact Gran Tierra's disclosures.

Gran Tierra has reviewed all other recently issued, but not yet adopted, accounting standard updates in order to determine their effects, if any, on its consolidated financial statements. Based on that review, Gran Tierra believes that the implementation of these standards will not materially impact Gran Tierra's consolidated financial position, operating results, cash flows, or disclosure requirments.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Our principal market risk relates to oil prices. Essentially 100% of our revenues are from oil sales at prices which are defined by contract relative to WTI and adjusted for transportation and quality, for 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.

We consider our exposure to interest rate risk to be immaterial as we hold only cash and cash equivalents. Interest rate exposures relate entirely to our investment portfolio, as we do not have short term or long term debt. 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 issuers at overnight rates, or government securities of the United States or Canadian federal governments such as Guaranteed Investment Certificates or Treasury Bills. We do not hold any of these investments for trading purposes. We do not hold equity investments.

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 West Texas intermediate oil. In Colombia, we receive 100% of our revenues in U.S. dollars. The majority of our capital expenditures in Colombia are in U.S. dollars and the majority of local office costs are in local currency. In Argentina, reference prices for oil are in U.S. dollars and revenues are received in Argentine pesos according to current exchange rates. The majority of capital expenditures within Argentina have been in U.S. dollars with local office costs generally in pesos. While we operate in South America exclusively, the majority of our acquisition expenditures have been valued and paid in U.S. dollars.

Additionally, foreign exchange gains/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/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 $104,000 for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

Item 8. Financial Statements and Supplementary Data.

Report of Independent Registered Chartered Accountants

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

We have audited the accompanying consolidated financial statements of Gran Tierra Energy Inc. and its subsidiaries, which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of operations and retained earnings (accumulated deficit), shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2010, 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, 2010 and 2009, and the results of its operations and its cash flows for each of three years in the period ended December 31, 2010 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, 2010, 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 24, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 24, 2011

Gran Tierra Energy Inc.
Consolidated Statements of Operations and Retained Earnings (Accumulated Deficit)
For the Years Ended December 31, 2010, 2009 and 2008
(Thousands of U.S. Dollars, Except Share and Per Share Amounts)

	Year Ended December 31,		
	2010	2009	2008
REVENUE AND OTHER INCOME			
Oil and natural gas sales	$ 373,286	$ 262,629	$ 112,805
Interest	1,174	1,087	1,224
	374,460	263,716	114,029
EXPENSES			
Operating	59,446	40,784	19,218
Depletion, depreciation, accretion and impairment (Note 5)	163,573	135,863	25,737
General and administrative	40,241	28,787	18,593
Derivative financial instruments (gain) loss (Note 11)	(44)	190	(193)
Foreign exchange loss	16,838	19,797	6,235
	280,054	225,421	69,590
INCOME BEFORE INCOME TAXES	94,406	38,295	44,439
Income tax expense (Note 8)	(57,234)	(24,354)	(20,944)
NET INCOME AND COMPREHENSIVE INCOME	37,172	13,941	23,495
RETAINED EARNINGS (ACCUMULATED DEFICIT), BEGINNING OF YEAR	20,925	6,984	(16,511)
RETAINED EARNINGS, END OF YEAR	$ 58,097	$ 20,925	$ 6,984
NET INCOME PER SHARE — BASIC	$ 0.15	$ 0.06	$ 0.19
NET INCOME PER SHARE — DILUTED	$ 0.14	$ 0.05	$ 0.16
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 6)	253,697,076	241,258,568	123,421,898
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 6)	264,304,831	253,590,103	143,194,590

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Consolidated Balance Sheets
As at December 31, 2010 and 2009
(Thousands of U.S. Dollars)

	As at December 31, 2010	2009
ASSETS		
Current Assets		
Cash and cash equivalents	$ 355,428	$ 270,786
Restricted cash	250	1,630
Accounts receivable	43,035	35,639
Inventory (Note 2)	5,669	4,879
Taxes receivable	6,974	1,751
Prepaids	1,940	1,820
Deferred tax assets (Note 8)	4,852	4,252
Total Current Assets	418,148	320,757
Oil and Gas Properties (using the full cost method of accounting)		
Proved	442,404	474,679
Unproved	278,753	234,889
Total Oil and Gas Properties	721,157	709,568
Other capital assets	5,867	3,175
Total Property, Plant and Equipment (Note 5)	727,024	712,743
Other Long Term Assets		
Restricted cash	1,190	162
Deferred tax assets (Note 8)	-	7,218
Other long term assets	311	347
Goodwill (Note 3)	102,581	102,581
Total Other Long Term Assets	104,082	110,308
Total Assets	$ 1,249,254	$ 1,143,808
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current Liabilities		
Accounts payable (Note 9)	$ 76,023	$ 36,786
Accrued liabilities (Note 9)	32,120	40,229
Derivative financial instruments (Note 11)	-	44
Taxes payable	43,832	28,087
Asset retirement obligation (Note 7)	338	450
Total Current Liabilities	152,313	105,596

Long Term Liabilities				
Deferred tax liability (Note 8)		204,570		216,625
Deferred remittance tax and other		1,036		903
Asset retirement obligation (Note 7)		4,469		4,258
Total Long Term Liabilities		210,075		221,786
Commitments and Contingencies (Note 10)				
Subsequent Events (Note 14)				
Shareholders' Equity				
Common shares (Note 6)		4,797		1,431
(240,440,830 and 219,459,361 common shares and 17,681,123 and 24,639,513 exchangeable shares, par value $0.001 per share, issued and outstanding as at December 31, 2010 and 2009 respectively)				
Additional paid in capital		821,781		766,963
Warrants		2,191		27,107
Retained earnings		58,097		20,925
Total Shareholders' Equity		886,866		816,426
Total Liabilities and Shareholders' Equity	$	1,249,254	$	1,143,808

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Consolidated Statements of Cash Flows
For the Years Ended December 31, 2010, 2009 and 2008
(Thousands of U.S. Dollars)

	Year Ended December 31, 2010	2009	2008
Operating Activities			
Net income	$ 37,172	$ 13,941	$ 23,495
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, accretion and impairment (Note 5)	163,573	135,863	25,737
Deferred taxes	(20,090)	(15,355)	(6,418)
Stock based compensation	8,025	5,309	2,520
Unrealized (gain) loss on financial instruments (Note 11)	(44)	277	(2,882)
Unrealized foreign exchange loss	14,786	19,496	6,985
Settlement of asset retirement obligations (Note 7)	(286)	(52)	(334)
Net changes in non-cash working capital			
Accounts receivable	(5,323)	(27,926)	34,943
Inventory	(1,221)	(1,849)	(107)
Prepaids	(120)	(717)	261
Accounts payable and accrued liabilities	(3,212)	36,875	10,697
Taxes receivable and payable	10,522	(409)	14,840
Net cash provided by operating activities	203,782	165,453	109,737
Investing Activities			
Restricted cash	352	(1,792)	-
Additions to property, plant and equipment	(152,299)	(80,932)	(55,217)
Proceeds from disposition of oil and gas properties (Note 5)	7,986	5,400	-
Cash acquired on acquisition net of acquisition costs (Note 3)	-	-	81,912
Long term assets and liabilities	36	968	446
Net cash provided by (used in) investing activities	(143,925)	(76,356)	27,141
Financing Activities			
Proceeds from issuance of common stock	24,785	4,935	21,687
Net cash provided by financing activities	24,785	4,935	21,687
Net increase in cash and cash equivalents	84,642	94,032	158,565
Cash and cash equivalents, beginning of year	270,786	176,754	18,189
Cash and cash equivalents, end of year	$ 355,428	$ 270,786	$ 176,754

Cash	$	272,151	$	182,197	$	110,688
Term deposits		83,277		88,589		66,066
Cash and cash equivalents, end of year	$	355,428	$	270,786	$	176,754
Supplemental cash flow disclosures:						
Cash paid for taxes	$	49,088	$	31,527	$	11,587
Non-cash investing activities:						
Non-cash working capital related to property, plant and equipment	$	48,640	$	17,972	$	11,096

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Consolidated Statements of Shareholders' Equity
For the Years Ended December 31, 2010, 2009 and 2008
(Thousands of U.S. Dollars)

	Year Ended December 31, 2010	2009	2008
Share Capital			
Balance, beginning of year	$ 1,431	$ 226	$ 95
Issue of common shares	3,366	1,205	131
Balance, end of year	4,797	1,431	226
Additional Paid in Capital			
Balance, beginning of year	766,963	754,832	76,805
Issue of common shares	19,119	2,650	663,405
Issue of stock options in a business combination (Note 3)	-	-	1,345
Exercise of warrants (Note 6)	24,916	2,777	10,113
Exercise of stock options	2,300	1,080	72
Stock based compensation expense	8,483	5,624	3,092
Balance, end of year	821,781	766,963	754,832
Warrants			
Balance, beginning of year	27,107	29,884	16,403
Issue of warrants (Note 3 and 6)	-	-	23,594
Exercise of warrants (Note 6)	(24,916)	(2,777)	(10,113)
Balance, end of year	2,191	27,107	29,884
Retained Earnings (Accumulated Deficit)			
Balance, beginning of year	20,925	6,984	(16,511)
Net income	37,172	13,941	23,495
Balance, end of year	58,097	20,925	6,984
Total Shareholders' Equity	$ 886,866	$ 816,426	$ 791,926

(See notes to the consolidated financial statements)

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
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 preparation of financial statements in accordance with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the consolidated financial statements, and revenues and expenses during the reporting period. 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 financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates and changes from those estimates are recorded when known. Oil and natural gas reserves and related present value of future cash flows, impairment assessments of oil and gas properties and goodwill, stock option expense, income taxes, asset retirement obligation, derivative financial instrument valuation, legal and environmental risks and exposures and any assumptions associated with valuation of oil and gas properties are all subject to estimation in the Company's financial results.

Foreign currency translation

The functional currency of the Company, including its subsidiaries in Colombia, Argentina, Peru and Brazil, 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 included in the consolidated statement of operations and retained earnings (accumulated deficit).

Fair value of financial instruments

The Company’s financial instruments are cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities and derivatives. The fair values of these financial instruments approximate their carrying values due to their immediate or short-term nature

Cash and cash equivalents

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

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

Restricted cash

Restricted cash relates to cash resources pledged to secure letters of credit. All letters of credit currently secured by cash relate to requirements for work commitment guarantees contained in exploration contracts.

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 and $0.3 million at December 31, 2010 and 2009, respectively.

Inventory

Inventory consists of crude oil in tanks and supplies. Crude oil in tanks is valued at the lower of cost or market value. Supplies are valued at lower of cost or market value. The cost of inventory is determined using the weighted average method. Crude oil inventories include expenditures incurred to produce, upgrade and transport the product to the storage facilities. Crude oil inventories at December 31, 2010 and 2009 are $3.6 million and $3.8 million, respectively. Supplies at December 31, 2010 and 2009 are $2.1 and $1.1 million, respectively.

Oil and gas properties

The Company uses the full cost method of accounting for its investment in oil and natural gas properties. Separate cost centers are maintained for each country in which the Company incurs costs. 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 in the period incurred. Interest costs related to unproved properties and properties under development are also capitalized to oil and natural gas properties. Unless a significant portion of the Company’s proved reserve quantities in a particular country are sold (25% or greater), proceeds from the sale of oil and natural gas properties are accounted for as a reduction to capitalized costs, and gains and losses are not recognized.

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. Unproved properties are excluded from the amortizable base until 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. Future development costs are added to the amortizable base.

Unproved properties are evaluated quarterly for possible impairments. If impairment has occurred, the impairment is transferred to proved properties and thus subject to amortization immediately. For prospects where a reserve base has not yet been established, the impairment is charged to earnings. This evaluation considers among other factors, seismic data, requirements to relinquish acreage, drilling results, remaining time in the commitment period, remaining capital plans, and political, economic, and market conditions.

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.

The Company performs a ceiling test calculation each quarter in accordance with the U.S. Securities and Exchange Commission ("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 ten percent, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the costs being amortized. If capitalized costs exceed this limit, the excess is charged as additional depletion expense. As a result of implementing SEC Final Rule, "Modernization of Oil and Gas Reporting" which revised the existing Regulation S-K and Regulation S-X reporting requirements to align with current industry practices and technological advances as at December 31, 2009, the Company calculates future net cash flows 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. In prior years, the Company determined future net cash flows by applying those prices in effect for each country at the end of the reporting period.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

Asset retirement obligations

The Company provides for future asset retirement obligations on its oil and natural gas properties based on estimates established by current legislation. The asset retirement obligation is initially measured at fair value and capitalized to capital assets as an asset retirement cost, using the credit adjusted interest rate to discount the obligation. The asset retirement obligation accretes until the time the asset retirement obligation is expected to settle while the asset retirement cost is amortized over the useful life of the underlying capital assets.

The amortization of the asset retirement cost and the accretion of the asset retirement obligation are included in depletion, depreciation, accretion and impairment (“DD&A”). Actual asset retirement costs are recorded against the obligation when incurred. Any difference between the recorded asset retirement obligations and the actual retirement costs incurred is recorded as a gain or loss in the period of settlement.

Other assets

Other assets, including additions and replacements, are recorded at cost upon acquisition and include furniture and fixtures, computer equipment, automobiles and assets under capital leases. The cost of repairs and maintenance is charged to expense as incurred. Depreciation related to assets under capital leases is recorded as part of DD&A in the consolidated statement of operations. Depreciation is provided using the declining-balance-basis at a 30% annual rate for computer equipment, furniture and fixtures and automobiles. Leasehold improvements are depreciated on a straight-line basis over the term of the related lease.

Revenue recognition

Revenue from the production of crude 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 crude oil is transferred to their pipeline. In Argentina, Gran Tierra transports product from the field to the customer’s refinery 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.

Goodwill

Goodwill represents the excess of the purchase price of business combinations over the fair value of net assets acquired and is tested for impairment at least annually unless business events indicate an impairment test is required. 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 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, 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 goodwill on the Company’s financial statements was a result of the acquisitions of Solana Resources Limited (“Solana”) and Argosy Energy International L.P. (“Argosy”), and relates entirely to the Colombia reporting segment. The Company performed annual impairment tests of goodwill at December 31, 2010 and 2009. Based on these assessments, no impairment of goodwill was identified.

Income taxes

Deferred 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 evaluation of an uncertain tax position is a two-step process. The first step is recognition: The Company determines whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. 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 second step is measurement: A tax position that meets the more-likely-than-not recognition threshold is measured to determine the amount of benefit to recognize in the financial statements. The tax position is measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company recognizes potential accrued interest and penalties related to unrecognized tax benefits as a component of income tax expense in the consolidated statement of operations. This is an accounting policy election made by the Company that is a continuation of the Company's historical policy and will continue to be consistently applied in the future.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

Income per share

Basic income per share calculations are based on the net income attributable to common shareholders for the period divided by the weighted average number of common shares issued and outstanding during the period. The diluted income per share calculation is based on the weighted average number of common shares outstanding during the period, plus the effects of dilutive common share equivalents. This method requires that the dilutive effect of outstanding options and warrants issued should be calculated using the treasury stock method. 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.

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 is recognized over the requisite service period of the option. Stock based compensation expense is included as part of oil and natural gas properties, operating expenses, and general and administrative expenses with a corresponding increase to contributed surplus and recognized using the accelerated method.

Accounting for oil and gas derivative instruments

The Company recognizes all derivative instruments as either assets or liabilities at fair value in its financial statements. The Company may or may not elect to designate a derivative instrument as a hedge against changes in the fair value of an asset or a liability (a “fair value hedge”) or against exposure to variability in expected future cash flows (a “cash flow hedge”). The accounting treatment for the changes in fair value of a derivative instrument is dependent upon whether or not a derivative instrument is a cash flow hedge or a fair value hedge, and upon whether or not the derivative is designated as a hedge as noted above. Changes in fair value of a derivative instrument designated as a cash flow hedge are recognized, to the extent the hedge is effective, in other comprehensive income until the hedged item is recognized in earnings. Changes in the fair value of a derivative instrument designated as a fair value hedge are recognized in the consolidated statement of operations along with the changes in fair value of the hedged item attributable to the hedged risk. Where hedge accounting is not elected or if a derivative instrument does not qualify as either a fair value hedge or a cash flow hedge, changes in fair value are recognized in earnings as a derivative financial instrument gain or loss. The Company’s derivative instruments, outstanding until February 2010, did not qualify as either a fair value hedge or a cash flow hedge and, at December 31, 2010, the Company has no derivative instruments outstanding.

Warrants

Upon issuance, the Company records warrants issued to purchase its common stock at fair-value; subsequently, the warrants are carried at amortized cost. The Company determines the fair value of warrants issued by using the Black-Scholes option pricing model. Warrants were assumed on the acquisition of Solana and their fair value of $23.6 million was recorded as part of the consideration paid for the acquisition (Note 3).

New accounting pronouncements

Variable Interest Entities

In June 2009, the Financial Accounting Standards Board (the “FASB”) issued revised accounting standards to improve financial reporting by enterprises involved with variable interest entities. The standards replace the quantitative-based risks and rewards calculation for determining which enterprise, if any, has a controlling financial interest in a variable interest entity with an approach focused on identifying which enterprise has the power to direct the activities of a variable interest entity that most significantly impact the entity’s economic performance and: (1) the obligation to absorb losses of the entity; or, (2) the right to receive benefits from the entity. This standard was effective for interim and annual reporting periods beginning after November 15, 2009. The implementation of this standard did not materially impact the Company’s consolidated financial position, operating results or cash flows.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

Fair Value Measurements
In January 2010, the FASB issued Accounting Standards Update (“ASU”), “Fair Value Measurements and Disclosures (Topic 820): Improving Disclosures about Fair Value Measurements”. This ASU amends existing disclosure requirements about fair value measurements by adding required disclosures about items transferred into and out of levels 1 and 2 in the fair value hierarchy; adding separate disclosures about purchases, sales, issuances, and settlements relative to level 3 measurements; and clarifying, among other things, the existing fair value disclosures about the level of disaggregation. This is effective for interim and annual reporting periods beginning after December 15, 2009, except for the disclosures about purchases, sales, issuances, and settlements in the roll forward of activity in Level 3 fair value measurements. Those disclosures are effective for fiscal years beginning after December 15, 2010, and for interim periods within those fiscal years. The implementation of this update on January 1, 2010 did not materially impact the Company’s disclosures.

Subsequent Events
In February 2010, the FASB issued ASU, "Subsequent Events (Topic 855)." The amendments remove the requirements for an SEC filer to disclose a date, in both issued and revised financial statements, through which subsequent events have been reviewed. This ASU was effective upon issuance. The implementation of this update did not materially impact the Company’s disclosures.

Stock Compensation
In April 2010, the FASB issued ASU, "Compensation–Stock Compensation (Topic 718)." The amendments clarify 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 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2010. The implementation of this update is not expected to materially impact the Company’s consolidated financial position, operating results or cash flows.

Receivables
In July 2010, the FASB issued ASU, "Receivables (Topic 310)." The update is intended to provide financial statement users with greater transparency about an entity’s allowance for credit losses and the credit quality of its financing receivables. The disclosures as of the end of a reporting period are effective for interim and annual reporting periods ending on or after December 15, 2010. The implementation of this update did not materially impact the Company’s disclosures.

Business Combinations
In December 2010, the FASB issued ASU, "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 date 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 is effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2010. The implementation of this

update is not expected to materially impact the Company’s disclosures.

3. Business Combinations

Solana Resources Limited (“Solana”)

On July 29, 2008, Gran Tierra announced that it had entered into an agreement providing for the business combination of Gran Tierra and Solana, an international resource company engaged in the acquisition, exploration, development and production of oil and natural gas in Colombia with its head office located in Calgary, Alberta, Canada. Under the terms of the agreement with Solana, each Solana shareholder received, for each Solana common share held, either: (1) 0.9527918 of a share of Gran Tierra common stock; or (2) 0.9527918 of a common share of a Canadian subsidiary of Gran Tierra (the “exchangeable shares”). The exchangeable shares: (a) have the same voting rights, dividend entitlements and other attributes as Gran Tierra common stock; (b) are exchangeable, at each stockholder's option, on a one-for-one basis into Gran Tierra common stock. Exchangeable shares, issued upon the acquisition, are listed on the Toronto Stock Exchange under the symbol GTX and will automatically be exchanged for Gran Tierra common stock five years from closing, and in certain other events. In addition, certain Solana stock options were exchanged for stock options of Gran Tierra based on the above exchange ratio, and holders of Solana warrants elected to continue to hold their warrants, which are exercisable into shares of common stock of Gran Tierra pursuant to the terms of such warrants and based on the above exchange ratio.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

The transaction was completed November 14, 2008 pursuant to a plan of arrangement in accordance with the Business Corporations Act (Alberta). Upon completion of the transaction, Solana became an indirect wholly-owned subsidiary of Gran Tierra. On a diluted basis, upon the closing of the plan of arrangement, Solana security holders owned approximately 49% of the combined company and Gran Tierra security holders owned approximately 51% of the combined company.

The acquisition was accounted for using the purchase method, with Gran Tierra being the acquirer, whereby the Solana assets acquired and liabilities assumed are recorded at their fair values at the acquisition date of November 14, 2008 and the results of Solana have been consolidated with those of Gran Tierra from that date. The fair value of Gran Tierra's shares was determined as the weighted average closing price of the common shares of Gran Tierra for the five-day period around the announcement date of July 29, 2008, being two days prior to and after the acquisition was agreed to and announced, and the announcement date. The fair value of each exchangeable share issued is equal to the fair value of a common share of Gran Tierra.

Under the terms of the acquisition, Gran Tierra acquired all of the issued and outstanding common shares of Solana in exchange for 120,620,967 shares comprised of 51,516,332 Gran Tierra common shares and 69,104,635 exchangeable shares of Gran Tierra Exchange Co, a wholly-owned subsidiary of Gran Tierra. In accordance with the provisions of the agreement, 490,001 Solana stock options were exchanged for 466,869 Gran Tierra stock options. Also, 7,500,000 Solana warrants were assumed on the date of the acquisition and were exchangeable for 7,145,938 Gran Tierra common shares. The fair value of the options and warrants was included as part of the consideration for this acquisition and was determined based on market price over a five day period before and after the announcement date using the Black-Scholes option pricing model with the following assumptions:

Warrants:

Exercise price (Canadian dollars per warrant)	$	2.00	
Risk-free interest rate		2.28	%
Expected life			1.7 years
Volatility		75	%
Expected annual dividend per share			Nil
Fair value per warrant	$	3.39	

Stock Options:

Exercise price (Canadian dollars per stock option)	$	2.36-$4.33	
Risk-free interest rate		2.28	%
Expected life			1.3-4.8 years
Volatility		71% - 75	%
Expected annual dividend per share			Nil
Weighted average fair value per option	$	2.75	

Based on the conditions existing at the completion date, November 14, 2008, the fair value of the Solana warrants, as determined by Gran Tierra, exceeded the fair value of the Solana warrants, as determined by Solana, by approximately $0.6 million, and was recorded by Gran Tierra immediately as compensation expense and reported as part of general and administrative expenses.

On November 14, 2008 and prior to the November 15, 2008 deadline, as contractually agreed, Gran Tierra issued 2 million common shares to acquire the participating interest in Solana's properties that, under the Colombian Participation Agreement entered into in 2006 with Crosby Capital LLC ("Crosby") as part of the acquisition of Argosy, would otherwise accrue to the former owners of Argosy. The ascribed value of common shares issued has been included in the purchase consideration for the acquisition as the completion of the acquisition was dependent on the successful acquisition of this participating interest. The shares were issued in a private placement, subject to a registration rights agreement, and were registered with the SEC in February 2009.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

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

(Thousands of U.S. Dollars)

Purchase Price:		
Common Shares/Exchangeable Shares issued net of share issue costs	$	631,451
Warrants		23,594
Stock options		1,345
Two million common shares issued under Colombian Participation Agreement		10,470
Transaction costs		4,938
	$	671,798
Purchase Price Allocated:		
Oil and Gas Properties		
Proved	$	320,773
Unproved		360,493
Other assets		1,113
Other long-term assets		1,329
Goodwill (1)(2)		87,576
Net working capital (including cash acquired)(2)		95,356
Asset retirement obligations		(3,148)
Deferred income taxes		(191,694)
	$	671,798

(1) Goodwill is not deductible for tax purposes and is subject to annual impairment test.
(2) Due to new information received during 2009, the Company reclassified $4.4 million from taxes payable to goodwill in the purchase price allocation relating to the Solana acquisition.

The unaudited pro forma results for the year ended December 31, 2008 is shown below, as if the acquisition had occurred on January 1, 2008. Pro forma results are not indicative of actual results or future performance.

(Unaudited) (Thousands of U.S. Dollars Except Per Share Amounts)		Year Ended December 31, 2008
Oil and natural gas sales and interest	$	221,043
Net income	$	66,886
Net income per share -basic	$	0.29
Net income per share - diluted	$	0.26

Argosy Energy International L.P. (“Argosy”)

In 2006, the Company recorded $15.0 million of goodwill in relation to the Argosy acquisition. This $15.0 million combined with the $87.6 recorded in relation to the Solana acquisition, totals the goodwill balance of $102.6 million at December 31, 2010 and 2009.

4. Segment and Geographic Reporting

The Company's reportable operating segments are Colombia and Argentina based on a geographic organization. The Company is primarily engaged in the exploration and production of oil and natural gas. Peru and Brazil are not reportable segments because the level of activity on these land holdings is not significant at this time and are included as part of the Corporate segment. The accounting policies of the reportable operating segments are the same as those described in the summary of significant accounting policies. The Company evaluates performance based on profit or loss from oil and natural gas operations before income taxes.

The results of Colombia and Corporate segments include the operations of Solana subsequent to the Company's acquisition of Solana (Note 3) on November 14, 2008.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

The following tables present information on the Company's reportable geographic segments:

	Year Ended December 31, 2010			
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Corporate	Total
Revenues	$ 359,302	$ 13,984	$ -	$ 373,286
Interest income	460	26	688	1,174
Depreciation, depletion, accretion and impairment	133,728	29,416	429	163,573
Depreciation, depletion, accretion and impairment - per unit of production	26.80	103.56	-	31.02
Segment income (loss) before income taxes	142,486	(27,247)	(20,833)	94,406
Segment capital expenditures (1)	$ 105,482	$ 33,930	$ 37,627	$ 177,039

	Year Ended December 31, 2009			
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Corporate	Total
Revenues	$ 248,834	$ 13,795	$ -	$ 262,629
Interest income	466	127	494	1,087
Depreciation, depletion, accretion and impairment	127,213	8,339	311	135,863
Depreciation, depletion, accretion and impairment - per unit of production	29.64	24.72	-	29.35
Segment income (loss) before income taxes	55,827	(4,230)	(13,302)	38,295
Segment capital expenditures	$ 81,364	$ 4,532	$ 2,228	$ 88,124

	Year Ended December 31, 2008			
(Thousands of U.S. Dollars except per unit of production amounts)	Colombia	Argentina	Corporate	Total
Revenues	$ 103,202	$ 9,603	$ -	$ 112,805
Interest income	995	23	206	1,224
Depreciation, depletion and accretion	22,199	3,390	148	25,737
Depreciation, depletion and accretion - per unit of production	20.41	13.95	-	19.34
Segment income (loss) before income taxes	58,490	(3,157)	(10,894)	44,439
Segment capital expenditures	$ 31,725	$ 11,690	$ 3,313	$ 46,728

	As at December 31, 2010			
(Thousands of U.S. Dollars)	Colombia	Argentina	Corporate	Total
Property, plant and equipment	$ 654,416	$ 29,031	$ 43,577	$ 727,024
Goodwill	102,581	-	-	102,581

Other assets		155,798		15,220		248,631		419,649
Total Assets	$	912,795	$	44,251	$	292,208	$	1,249,254

	As at December 31, 2009			
(Thousands of U.S. Dollars)	Colombia	Argentina	Corporate	Total
Property, plant and equipment	$ 681,854	$ 24,510	$ 6,379	$ 712,743
Goodwill	102,581	-	-	102,581
Other assets	123,380	12,574	192,530	328,484
Total Assets	$ 907,815	$ 37,084	$ 198,909	$ 1,143,808

(1) Net of net proceeds from the disposition of the Garibay overriding royalty in 2010 (see Note 5) and the Guachiria Blocks in 2009 (see Note 5).

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 2010, the Company had one significant customer for its Colombian crude oil, Ecopetrol S.A. ("Ecopetrol"), a Colombian majority state owned agency. Sales to Ecopetrol accounted for 96% of the Company's revenues in 2010, 94% in 2009, and 89% in 2008. In Argentina, the Company had one significant customer, Refineria del Norte S.A. ("Refinor"). Sales to Refinor accounted for 4% of the Company's revenues in 2010, 6% in 2009, and 9% in 2008.

5. Property, Plant and Equipment

	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

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

	As at December 31, 2009		
(Thousands of U.S. Dollars)	Cost	Accumulated DD&A	Net book value
Oil and natural gas properties			
Proved	$ 648,061	$ (173,382)	$ 474,679
Unproved	234,889	-	234,889
	882,950	(173,382)	709,568
Furniture and fixtures and leasehold improvements	3,843	(2,185)	1,658
Computer equipment	3,148	(1,907)	1,241
Automobiles	513	(237)	276
Total Property, Plant and Equipment	$ 890,454	$ (177,711)	$ 712,743

DD&A for 2010 included a $23.6 million ceiling test impairment loss in the Company's Argentina cost center as compared to 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.

The Company capitalized $4.1 million (2009 - $1.6 million; 2008 - $1.9 million) of general and administrative expenses related to the Colombian full cost center, including $0.3 million (2009 - $0.2 million; 2008 - $0.4 million) of stock based compensation expense, and $1.2 million (2008 - $0.6 million; 2007 - $0.8 million) of general and administrative expenses in the Argentina full cost center, including $0.2 million (2009 - $0.1 million; 2008 - $0.1 million) of stock based compensation.

The unproved oil and natural gas properties consist of exploration lands held in Colombia, Argentina and Peru. The Company had $228.8 million (December 31, 2009 - $229.1 million) in unproved assets in Colombia, $9.4 million (December 31, 2009 - $0.4 million) of unproved assets in Argentina and $28.2 million (December 31, 2009 - $5.4 million) of unproved assets in Peru, and $12.4 million (December 31, 2009 – nil) of unproved assets in Brazil for a total of $278.8 million (December 31, 2009 - $234.9 million). These properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration dictates whether or not future areas will be developed.

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 net proceeds of $6.3 million in 2009. 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.

In October 2010, the Company recorded proceeds of $6.4 million for the sale of an overriding interest in the Garibay Block in Colombia.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2010:

	Costs Incurred in					
(Thousands of U.S. Dollars)	2010	2009	2008	2007	2006	Total
Acquisition costs - Colombia	$ 5,000	$ -	$ 188,001	$ -	$ 1,637	$ 194,638
Acquisition costs - Peru	2,000	-	-	-	-	2,000
Acquisition costs - Brazil	12,395	-	-	-	-	12,395
Exploration costs - Argentina	3,933	163	229	-	-	4,325
Exploration costs - Colombia	27,812	3,376	487	-	-	31,675
Exploration costs - Peru	20,847	1,969	2,767	656	-	26,239
Development costs - Argentina	5,021	-	-	-	-	5,021
Development costs - Colombia	2,460	-	-	-	-	2,460
Total oil and natural gas properties not subject to depletion	$ 79,468	$ 5,508	$ 191,484	$ 656	$ 1,637	$ 278,753

6. Share Capital

The Company's authorized share capital consists of 595,000,002 shares of capital stock, of which 570 million are designated as common stock, par value $0.001 per share, 25 million are designated as preferred stock, par value $0.001 per share (collectively, "common stock"), and two shares are designated as special voting stock, par value $0.001 per share. On June 16, 2009, the shareholders of Gran Tierra approved an amendment to the Articles of Incorporation to increase the authorized number of shares of common stock from 300,000,000 to 570,000,000 shares. As at December 31, 2010, outstanding share capital consists of 240,440,830 common voting shares of the Company, 9,870,011 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, 2010, the Company had 7,769,864 warrants outstanding to purchase 3,884,932 common shares for $1.05 per share, expiring between June 20, 2012 and June 30, 2012. For the year ended December 31, 2010, 11,127,527 common shares were issued upon the exercise of 15,109,116 warrants (year ended December 31, 2009, 4,221,193 common shares were issued upon the exercise of 10,913,660 warrants; year ended December 31, 2008, 20,479,546 common shares were issued upon the exercise of 41,138,370 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.

Stock Options

As at December 31, 2010, the Company has 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 November 14, 2008, 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 9,000,000 shares to 18,000,000 shares. On June 16, 2010, another amendment to the Company’s 2007 Equity Incentive plan was approved by shareholders, which increased the number of shares of common stock available for issuance thereunder from 18,000,000 shares to 23,306,100 shares.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

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 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, 2010, 2,895,553 common shares were issued upon the exercise of 2,895,553 stock options (year ended December 31, 2009 – 1,391,028; year ended December 31, 2008 – 209,164). The following options are outstanding as of December 31, 2010:

	Number of Outstanding Options	Weighted Average Exercise Price $/Option	Number of Nonvested Options	Weighted Average Grant-Date Fair Value $/Option
Balance, December 31, 2009	11,088,616	$ 2.43	5,959,212	$ 1.74
Granted in 2010	3,045,000	5.97	3,045,000	3.36
Exercised in 2010	(2,895,553)	(1.95)	-	-
Vested in 2010	-	-	(3,192,516)	1.61
Forfeited in 2010	(295,005)	(4.09)	(295,005)	1.69
Balance, December 31, 2010	10,943,058	$ 3.49	5,516,691	$ 2.68

The weighted average grant date fair value for options granted in 2010 was $3.36 (2009 - $2.43; 2008 - $1.55). The intrinsic value of options exercised in 2010 was $12.8 million (2009 - $2.9 million; 2008 – $0.8 million). The total fair value of shares vested during 2010 was $5.1 million (2009 - $4.7 million; 2008 - $2.0 million).

The table below summarizes stock options outstanding at December 31, 2010:

Range of Exercise Prices ($/option)	Number of Outstanding Options	Weighted Average Exercise Price $/Option	Weighted Average Expiry Years
0.50 to 1.30	1,280,836	$ 1.10	5.5
1.31 to 2.00	88,334	1.72	6.9
2.01 to 3.50	5,675,555	2.45	7.8
3.51 to 5.50	478,333	4.45	8.8
5.51 to 7.75	3,420,000	6.02	9.1
Total	10,943,058	$ 3.49	8.0

The aggregate intrinsic value of options outstanding at December 31, 2010 is $49.9 million (2009 - $39.0 million) based on the Company's closing stock price of $8.05 (2009 - $5.73) for that date. At December 31, 2010, there was $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.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the years ended December 31, 2010, 2009, and 2008
Expressed in U.S. Dollars, unless otherwise stated

The table below summarizes exercisable stock options at December 31, 2010:

Range of Exercise Prices ($/option)	Number of Exercisable Options	Weighted Average Exercise Price $/Option		Weighted Average Expiry Years
0.50 to 1.30	1,280,836	$	1.1	5.5
1.31 to 2.00	88,334	$	1.72	6.9
2.01 to 3.50	3,747,200	$	2.42	7.7
3.51 to 5.50	111,665	$	4.77	8.8
5.51 to 7.75	198,332	$	6.54	8.4
Total	5,426,367	$	2.30	7.2

The weighted average grant date fair value for options vested in 2010 was $1.61 (2009 - $1.38). The aggregate intrinsic value of options exercisable at December 31, 2010 is $49.9 million (2009 - $19.8 million) based on the Company's closing stock price of $8.05 for that date.

In 2010, the stock based compensation expense was $8.5 million (2009 - $5.6 million; 2008 - $3.1 million) of which $7.2 million (2009 - $4.5 million; 2008 - $2.3 million) was recorded in general and administrative expense and $0.8 million (2009 - $0.8 million; 2008 - $0.2 million) was recorded in operating expense in the consolidated statement of operations. In 2010, $0.5 million (2009 - $0.3 million; 2008 - $0.6 million) of stock based compensation was capitalized as part of exploration and development costs.

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. 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 contractual term of the stock options is based on the U.S. Treasury yield curve in effect at the time of grant.

	Year Ended December 31,					
	2010		2009		2008	
Dividend yield (per share)	$	nil	$	nil	$	nil
Volatility	84% to 90%		94% to 98%		75% to 103%	
Risk-free interest rate	0.2% to 0.5%		0.4% to 0.6%		1.1% to 2.1%	
Expected term	3 years		3 years		3 years	
Estimated forfeiture percentage (per year)	10	%	10	%	10	%

Weighted average shares outstanding

	Year Ended December 31,		
	2010	2009	2008
Weighted average number of common and exchangeable shares outstanding	253,697,076	241,258,568	123,421,898
Shares issuable pursuant to warrants	3,750,781	9,503,818	14,663,885
Shares issuable pursuant to stock options	7,402,966	5,797,322	6,020,738

Shares to be purchased from proceeds of stock options	(545,992)	(2,969,605)	(911,931)
Weighted average number of diluted common and exchangeable shares outstanding	264,304,831	253,590,103	143,194,590
Income (loss) per share			

At December 31, 2010, 2009 and 2008, 290,000, 1,080,000 and 100,000 options to purchase common shares were excluded from the diluted income per share calculation as the instruments were anti-dilutive.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

7. Asset Retirement Obligation

As at December 31, 2010 the Company's asset retirement obligation was comprised of a Colombian obligation in the amount of $3.7 million (December 31, 2009 - $3.5 million) and an Argentine obligation in the amount of $1.1 million (December 31, 2009 - $1.2 million). The undiscounted asset retirement obligation is $8.7 million. 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)	2010	2009
Balance, beginning of year	$ 4,708	$ 4,251
Settlements	(286)	(52)
Disposal	(720)	(734)
Liability incurred	719	921
Foreign exchange	58	24
Accretion	328	298
Balance, end of year	$ 4,807	$ 4,708
Asset retirement obligation - current	$ 338	$ 450
Asset retirement obligation - long term	4,469	4,258
Balance, end of year	$ 4,807	$ 4,708

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

8. 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)	2010	2009	2008
Income before income taxes	$ 94,406	$ 38,295	44,439
	35 %	35 %	35 %
Income tax expense (benefit) expected	33,042	13,403	15,554
Foreign currency translation adjustments	6,409	1,099	4,636
Impact of foreign taxes	(3,094)	(1,565)	(1,337)
Enhanced tax depreciation incentive	(7,971)	(3,380)	(4,560)
Stock based compensation	2,381	1,814	707
Non-deductible royalty	5,506	3,532	3,129
Increase in valuation allowance	19,991	16,199	8,537
Partnership and branch (loss) income pick-up in the United States and Canada	(3,957)	(5,931)	21,673
Utilization of foreign tax credits	-	71	(26,989)
Other permanent differences	4,927	(888)	(406)
Total income tax expense	$ 57,234	$ 24,354	$ 20,944
Current income tax	76,913	38,795	25,256
Deferred tax recovery	(19,679)	(14,441)	(4,312)
Total income tax expense	$ 57,234	$ 24,354	$ 20,944

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

	As at December 31,	
(Thousands of U.S. Dollars)	2010	2009
Deferred Tax Assets		
Tax benefit of loss carryforwards	$ 27,527	$ 22,318
Tax basis in excess of book basis	7,975	1,691
Foreign tax credits and other accruals	16,895	15,508
Capital losses	1,413	1,481
Deferred tax assets before valuation allowance	53,810	40,998
Valuation allowance	(48,958)	(29,528)
	$ 4,852	$ 11,470
Deferred tax assets - current	$ 4,852	$ 4,252
Deferred tax assets - long-term	-	7,218
	4,852	11,470
Deferred Tax Liabilities		
Long-term - book value in excess of tax basis	(204,570)	(216,625)
	(204,570)	(216,625)
Net Deferred Tax Liabilities	$ (199,718)	$ (205,155)

The Company was required to calculate a deferred remittance tax in Colombia based on 7% of profits which are not reinvested in the business on the presumption that such profits would be transferred to the foreign owners up to December 31, 2006. As of January 1, 2007, the Colombian government rescinded this law; therefore, no further remittance tax liabilities will be accrued. The historical balance which was included in the Company's financial statements as of December 31, 2010 was $0.5 million (December 31, 2008 - $0.9 million).

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 2004 through 2010 in most jurisdictions.

As at December 31, 2010, the Company has deferred tax assets relating to net operating loss carryforwards of $27.5 million (December 31, 2009 - $22.3 million) and capital losses of $1.4 million (December 31, 2009 – $1.5 million) before valuation allowances. Of these losses, $20.5 million (December 31, 2009 - $18.2 million) are losses generated by the foreign subsidiaries of the Company. Of the total losses nil (December 31, 2009 - $0.1 million) will begin to expire by 2011 and $28.9 million of net operating losses (December 31, 2009 - $23.7 million) will begin to expire thereafter.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

9. Accounts Payable and Accrued Liabilities

The balances in accounts payable and accrued liabilities are comprised of the following:

	As at December 31, 2010			
(Thousands of U.S. Dollars)	Colombia	Argentina	Corporate	Total
Property, plant and equipment	$ 32,854	$ 10,452	$ 9,815	$ 53,121
Payroll	3,256	186	2,300	5,742
Audit, legal, consultants	-	140	1,692	1,832
General and administrative	1,039	590	433	2,062
Operating	43,037	2,141	208	45,386
Total	$ 80,186	$ 13,509	$ 14,448	$ 108,143

	As at December 31, 2009			
(Thousands of U.S. Dollars)	Colombia	Argentina	Corporate	Total
Property, plant and equipment	$ 17,723	$ 844	$ 213	$ 18,780
Payroll	1,792	339	1,052	3,183
Audit, legal, consultants	-	137	1,472	1,609
General and administrative	2,542	284	213	3,039
Operating	48,756	1,648	-	50,404
Total	$ 70,813	$ 3,252	$ 2,950	$ 77,015

10. Commitments and Contingencies

Leases

Gran Tierra holds three categories of operating leases: office, vehicle and housing. The Company pays monthly amounts of $0.2 million for office leases, $11,000 for vehicle leases and $5,000 for certain employee accommodation leases in Colombia, Argentina and Peru. Future lease payments as at December 31, 2010 are as follows:

		As at December 31, 2010 Payments Due in Period			
Contractual Obligations (Thousands of U.S. Dollars)	Total	Less than 1 Year	1 to 3 years	3 to 5 years	More than 5 years
Operating leases	$5,444	$2,476	$2,068	$900	$ -
Software and telecommunication	1,456	1,137	319	-	-
Drilling, completion, facility Construction and oil transportation services	71,412	62,754	8,658	-	-
Consulting	393	393	-	-	-
Total	$78,705	$66,760	$11,045	$900	$ -

Total rent expense for 2010 was $2.3 million (2008 - $2.1 million; 2008 - $0.9 million).

Guarantees

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 liquidity, consolidated financial position or results of operations.

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 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 Bogotá. 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 $5.5 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 determinable. Gran Tierra believes the resolution of these matters would not have a material adverse effect on the Company's consolidated financial position or results of operations.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

11. Financial Instruments, Fair Value Measurements and Credit Risk

The Company’s financial instruments recognized in the balance sheet consist of cash and cash equivalents, restricted cash, accounts receivable, accounts payable, accrued liabilities, and derivative financial instruments. The estimated fair values of the financial instruments have been determined based on the Company’s assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction. As at December 31, 2010, the fair values of financial instruments approximate their book amounts due to the short term maturity of these instruments. Most of the Company’s accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. 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. The book value of the accounts receivable reflects management’s assessment of the associated credit risks. The Company holds no derivative instruments at December 31, 2010.

Additionally, foreign exchange gains/losses result from the 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, a foreign exchange gain/loss 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 $104,000) for each one peso decrease in the exchange rate of the Colombian peso to one U.S. dollar.

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 2010, the Company had one significant customer for its Colombian crude oil, Ecopetrol. In Argentina, the Company had one significant customer, Refinor.

The Company recognizes the fair value of its derivative instruments as assets or liabilities on the balance sheet. None of the Company's derivative instruments, which expired in February 2010, qualified as fair value hedges or cash flow hedges, and accordingly, changes in fair value of the derivative instruments were recognized as income or expense in the consolidated statement of operations and retained earnings (accumulated deficit) with a corresponding adjustment to the fair value of derivative instruments recorded on the balance sheet. Under the terms of the Credit Facility with Standard Bank (Note 12), the Company was required to enter into a derivative instrument for the purpose of obtaining protection against fluctuations in the price of oil in respect of at least 50% of the June 30, 2006 Independent Reserve Evaluation Report projected aggregate net share of Colombian production after royalties for the three year term of the Facility. In accordance with the terms of the Facility, the Company entered into a costless collar derivative instrument for crude oil based on West Texas Intermediate (“WTI”) price, with a floor of $48.00 and a ceiling of $80.00, for a three year period ending February 2010, for 400 barrels per day from March 2007 to December 2007, 300 barrels per day from January 2008 to December 2008, and 200 barrels per day from January 2009 to February 2010. The company had no derivative contracts outstanding at December 31, 2010.

	Year Ended December 31,		
(Thousands of U.S. Dollars)	2010	2009	2008
Realized financial derivative (gain) loss	$ -	$ (87)	$ 2,689
Unrealized financial derivative (gain) loss	(44)	277	(2,882)

Derivative financial instruments (gain) loss	$	(44)	$	190	$	(193)

	As at December 31,			
Assets (Liabilities)	2010		2009	
Derivative financial instruments	$	-	$	(44)

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

Certain of Gran Tierra's assets and liabilities are reported at fair value in the accompanying consolidated balance sheets. The following tables provide fair value measurement information for such assets and liabilities as at December 31, 2010 and December 31, 2009.

The carrying values of cash and cash equivalents, restricted cash, accounts receivable and accounts payable (including accrued liabilities) included in the accompanying consolidated balance sheets approximated fair value at December 31, 2010 and December 31, 2009. These assets and liabilities are not presented in the following tables.

	As at December 31, 2010				
			Fair Value Measurements Using:		
Financial Assets (Liabilities) (Thousands of U.S. Dollars)	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Crude oil collar	$ -	$ -	$ -	$ -	$ -

	As at December 31, 2009				
			Fair Value Measurements Using:		
Financial Assets (Liabilities) (Thousands of U.S. Dollars)	Carrying Amount	Total Fair Value	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Crude oil collar	$ (44)	$ (44)	$ -	$ (44)	$ -

GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. As presented in the table above, this hierarchy consists of three broad levels. Level 1 inputs on the hierarchy consist of unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 and 3 inputs have lower priorities. The Company uses appropriate valuation techniques based on the available inputs to measure the fair values of assets and liabilities. When available, Gran Tierra measures fair value using Level 1 inputs because they generally provide the most reliable evidence of fair value.

The Company uses a Level 2 method to measure the fair value of its crude oil collars. The fair values of the crude oil are estimated using internal discounted cash flow calculations based upon forward commodity price curves, non-binding quotes obtained from brokers for contracts with similar terms which can be substantially observed or corroborated in the marketplace, or quotes obtained from counterparties to the agreements. The Company does not have any other assets or liabilities whose fair value is measured using Level 1 or 3 methods.

The following methods and assumptions were used to estimate the fair values of the assets and liabilities in the table above.

Level 1 Fair Value Measurements
The Company does not have any assets or liabilities whose fair value is measured using this method.

Level 2 Fair Value Measurements
Crude oil collars - The fair values of the crude collars were estimated using internal discounted cash flow calculations based upon forward commodity price curves, non-binding quotes obtained from brokers for contracts with similar terms which could be substantially observed or corroborate in the marketplace, or quotes obtained from counterparties to the agreements.

Gran Tierra Energy Inc.
Notes to the Consolidated Financial Statements
For the Years Ended December 31, 2010, 2009 and 2008
Expressed in U.S. Dollars, unless otherwise stated

Level 3 Fair Value Measurements
The Company does not have any financial assets or financial liabilities whose fair value is measured using this method.

12. Credit Facilities

Effective February 28, 2007, the Company entered into a credit facility with Standard Bank Plc. 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. As at December 31, 2009, no amount was drawn-down under this facility. This facility expired February 22, 2010.

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 the Company’s two 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 USD LIBOR rate plus 3.5%. In addition, a stand-by fee of 1.50% per annum is charged on the unutilized balance of the committed borrowing base and is included in general and administrative 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, 2010, the Company had not drawn down any amounts under this facility.

13. Related Party Transactions

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 runs from February 1, 2009 to August 31, 2011 and the sublease payment is $7,800 per month plus approximately $4,000 for operating and other expenses. The terms of the sublease were consistent with market conditions in the Calgary, Alberta, Canada real estate market.

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. At December 31, 2010, $0.8 million was capitalized and included in accounts payable related to this contract, the terms of which are consistent with market conditions.

14. Subsequent Events

On January 12, 2011, the Company entered into an agreement to sublease office space to a company for 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, at $4,444 per month, the terms are consistent with market conditions in the Calgary, Alberta, Canada real estate market.

On January 17, 2011, the Company entered into an Arrangement Agreement (the "Agreement") to acquire all the issued and outstanding shares and warrants of Petrolifera Petroleum Limited ("Petrolifera"). Petrolifera is a Canadian based international oil and gas company that trades on the Toronto Stock Exchange and has oil and gas assets in Argentina, Colombia, and Peru. Under the terms of the Agreement, Petrolifera shareholders will receive 0.1241 of a share of Gran Tierra Energy, for every Petrolifera share held. In addition, we will issue replacement warrants for the outstanding warrants to purchase Petrolifera common shares, in the amount of 0.1241 of a Gran Tierra warrant for each Petrolifera warrant. A total of approximately 19 million of Gran Tierra's shares are expected to be issued, which represents approximately an 8% increase in shares outstanding. Total consideration for the transaction will be approximately $195 million, including the assumption of Petrolifera's debt, working capital and investments as of September 30, 2010. The Agreement is subject to regulatory, court, stock exchange, and Petrolifera securityholder approvals and is scheduled to close in March 2011.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

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. See Critical Accounting Estimates in Item 7 for a description of Gran Tierra's reserves estimation process.

PROVED RESERVES NET OF ROYALTIES (1)

Crude oil is in barrels and natural gas is in million cubic feet	Colombia		Argentina		Total	
	Oil	Gas	Oil	Gas	Oil	Gas
Proved Developed and Undeveloped Reserves, December 31, 2007	4,383,000	-	2,035,000	-	6,418,000	-
Extensions and Discoveries	5,344,202	-	377,300	-	5,721,502	-
Purchases of Reserves in Place	9,016,148	1,179	-	-	9,016,148	1,179
Production	(1,085,198)	(15)	(242,947)	-	(1,328,145)	(15)
Revisions of Previous Estimates	22,848	(2)	(612,353)	-	(589,505)	(2)
Proved Developed and Undeveloped reserves, December 31, 2008	17,681,000	1,162	1,557,000	-	19,238,000	1,162
Extensions and Discoveries	2,025,000	-	-	-	2,025,000	-
Purchases of Reserves in Place	(113,000)	-	-	-	(113,000)	-
Production	(4,284,230)	(49)	(337,316)	-	(4,621,546)	(49)
Revisions of Previous Estimates	5,482,230	-	71,316	756	5,553,546	756
Proved Developed and Undeveloped Reserves, December 31, 2009	20,791,000	1,113	1,291,000	756	22,082,000	1,869
Extensions and Discoveries	3,107,400	-	43,300	-	3,150,700	-
Purchases of Reserves in Place	-	-	-	-	-	-
Production	(4,877,600)	(277)	(296,800)	-	(5,174,400)	(277)
Revisions of Previous Estimates	3,464,400	396	75,200	(756)	3,539,600	(360)
Proved Developed and Undeveloped Reserves, December 31, 2010	22,485,200	1,232	1,112,700	-	23,597,900	1,232
Proved Developed Reserves, December 31, 2008 (2)	7,832,000	-	1,134,000	-	8,966,000	-
Proved Developed Reserves, December 31, 2009 (2)	20,194,000	1,113	1,080,000	756	21,274,000	1,869
Proved Developed Reserves, December 31, 2010 (2)	18,528,000	1,232	940,000	-	19,468,000	1,232

(1) Proved oil and gas reserves are the estimated quantities of natural gas, crude oil, condensate and natural gas liquids 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.

B. Capitalized Costs

	Proved Properties	Unproved Properties	Accumulated DD&A	Capitalized Costs
Capitalized Costs, December 31, 2009	$ 648,061	$ 229,497	$ (173,382)	$ 704,176
Colombia	104,504	(332)	(132,050)	(27,878)
Argentina	24,697	8,954	(29,426)	4,225
Capitalized Costs, December 31, 2010	$ 777,262	$ 238,119	$ (334,858)	$ 680,523

C. Costs Incurred

		Oil and Gas	
	Colombia	Argentina	Total
Total Costs Incurred before DD&A			
As at December 31, 2007	$ 52,726	$ 23,360	$ 76,086
Property Acquisition Costs			
Proved	$ 320,773	$ -	$ 320,773
Unproved	360,493	-	360,493
Exploration Costs	3,443	7,990	11,433
Development Costs	27,597	3,874	31,471
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

D. Results of Operations for Producing Activities

	Colombia	Argentina	Total
Year ended December 31, 2008			
Net Sales	$ 103,202	$ 9,603	$ 112,805
Production Costs	(12,117)	(7,027)	(19,144)
Exploration Expense	-	-	-
DD&A	(22,183)	(3,355)	(25,538)
Income Tax (Expense) Recovery	(22,063)	1,122	(20,941)
Results of Operations	$ 46,839	$ 343	$ 47,182
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	(24,354)
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) Recovery	(51,047)	(5,687)	(56,734)
Results of Operations	$ 125,774	$ (29,937)	$ 95,837

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 for 2010 and 2009 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. Future cash inflows for 2008 are computed by applying year end prices to Gran Tierra's after royalty share of estimated annual future production from proved oil and gas reserves. The 2010 twelve month period unweighted arithmetic average of the price as of the first day of each month within that twelve month period was $78.23 (2009 - $61.04) for Colombia and $50.18 (2009 – $40.98) for Argentina. The period end oil prices at December 31, 2008 were $44.60 for Colombia and $33.94 for Argentina. The calculated weighted average production costs at December 31, 2010 were $10.48 (2009 - $14.92; 2008 – $12.21) for Colombia and $18.87 (2009 - $20.73; 2008 – $13.05) for Argentina. Future development and production costs to be incurred in producing and further developing the proved reserves are based on year end cost indicators. Future income taxes are computed by applying year end statutory tax rates. These rates reflect allowable deductions and tax credits, and are applied to the estimated pre-tax future net cash flows.

Discounted future net cash flows are calculated using 10% mid-year discount factors. The calculations assume the continuation of existing economic, operating and contractual conditions. However, such arbitrary assumptions have not proved to be the case in the past. Other assumptions could give rise to substantially different results.

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

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

	Colombia	Argentina	Total
December 31, 2008			
Future Cash Inflows	$ 734,727	$ 52,856	$ 787,583
Future Production Costs	(131,317)	(19,154)	(150,471)
Future Development Costs	(159,219)	(4,279)	(163,498)
Future Site Restoration Costs	(1,738)	(226)	(1,964)
Future Income Tax	(123,634)	(8,588)	(132,222)
Future Net Cash Flows	318,819	20,609	339,428
10% Discount Factor	(60,180)	(4,126)	(64,306)
Standardized Measure	$ 258,639	$ 16,483	$ 275,122
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

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:

	2010	2009	2008
Beginning of Year	$ 406,384	$ 275,122	$ 196,284
Sales and Transfers of Oil and Gas Produced, Net of Production Costs	(313,840)	(222,479)	(94,598)
Net Changes in Prices and Production Costs Related to Future Production	208,649	147,810	(109,116)
Extensions, Discoveries and Improved Recovery, Less Related Costs	32,194	54,388	115,089
Development Costs Incurred during the Period	107,856	59,024	28,084
Revisions of Previous Quantity Estimates	140,893	149,597	(28,716)
Accretion of Discount	58,043	38,934	28,970
Purchases of Reserves in Place	-	-	184,470
Sales of Reserves in Place	-	3,035	-
Net change in Income Taxes	(39,180)	(99,047)	(45,345)
End of Year	$ 600,999	$ 406,384	$ 275,122

2) Summarized Quarterly Financial Information

	Revenue and other Income	Expenses	Income (Loss) Before Income Taxes	Income Taxes	Net Income (Loss)	Basic Earnings Net Income (Loss) Per Share - Basic	Diluted Net Income (Loss) Per Share - Diluted
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
2009							
First Quarter	$ 33,565	$ 19,518	$ 14,047	$ (85)	$ 14,132	$ 0.06	$ 0.06
Second Quarter	58,511	82,586	(24,075)	4,125	(28,200)	(0.12)	(0.12)
Third Quarter	75,354	70,211	5,143	7,959	(2,816)	(0.01)	(0.01)
Fourth Quarter	96,286	53,106	43,180	12,355	30,825	0.13	0.12
	$ 263,716	$ 225,421	$ 38,295	$ 24,354	$ 13,941	$ 0.06	$ 0.05

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

None.

Item 9A. Controls and Procedures

Disclosure Controls and Procedures

We have established disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, or Exchange Act. Our management, including our Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of the end of the period covered by this report, as required by Rule l3a-15(e) of the Exchange Act. Based on their evaluation, our principal executive and principal financial officers have concluded that Gran Tierra's disclosure controls and procedures were effective as of December 31, 2010 to provide reasonable assurance that the information required to be disclosed by Gran Tierra in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC rules and forms and that such information is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting

Gran Tierra’s management is responsible for establishing and maintaining adequate internal control over financial reporting for Gran Tierra, as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Under the supervision and with the participation of Gran Tierra’s management, including our principal executive and principal financial officers, Gran Tierra conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (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, 2010.

The effectiveness of Gran Tierra’s internal control over financial reporting as of December 31, 2010 has been audited by Deloitte & Touche LLP, independent registered chartered accountants.

Changes in Internal Control Over Financial Reporting

During the quarter ended December 31, 2010, 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.

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, 2010, 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, 2010, 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 accepting auditing standards and the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as at and for the year ended December 31, 2010 of the Company and our report dated February 24, 2011 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Independent Registered Chartered Accountants
Calgary, Canada
February 24, 2011

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 2011 Annual Meeting of Stockholders (our "Proxy Statement"), a copy of which will be filed with the Securities and Exchange Commission on or before April 30, 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 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 2010.

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," 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, 2010:

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	10,943,058	$ 3.49	7,867,297
Equity compensation plans not approved by security holders	-	-	-
Total	10,943,058	$ 3.49	7,867,297

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

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

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

Item 14. Principal Accounting Fees and Services

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

PART IV

Item 15. Exhibits, Financial Statement Schedules

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

(1) Financial Statements

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

(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 25, 2011 By: /s/ Dana Coffield
Dana Coffield
Chief Executive Officer and President
(Principal Executive Officer)

Date: February 25, 2011 By: /s/ Martin Eden
Martin Eden
Chief Financial Officer
(Principal Financial and Accounting Officer)

POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS, that each person whose signature appears below constitutes and appoints Dana Coffield and Martin Eden, 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 25, 2011
/s/ Martin Eden Martin Eden	Chief Financial Officer (Principal Financial and Accounting Officer)	February 25, 2011
/s/ Jeffrey Scott Jeffrey Scott	Chairman of the Board, Director	February 25, 2011
/s/ Verne Johnson Verne Johnson	Director	February 25, 2011
/s/ Nicholas G. Kirton Nicholas G. Kirton	Director	February 25, 2011
/s/ J. Scott Price J. Scott Price	Director	February 25, 2011
/s/ Ray Antony Ray Antony	Director	February 25, 2011
/s/ Gerry Macey Gerry Macey	Director	February 25, 2011

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.	
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	2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on August 6, 2010 (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	2008 Executive Officer Cash Bonus Compensation and 2009 Cash Compensation*	Incorporated by reference to Item 5.02 of the Current Report on Form 8-K, filed with the SEC on December 17, 2008 (File No. 001-34018).
10.19	2009 Executive Officer Cash Bonus Compensation and 2010 Cash Compensation*	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).
10.20	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).
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	Assignment and Assumption Agreement, dated as of August 24, 2009, by and among Gran Tierra Energy Inc., Gran Tierra Energy Cayman Islands Inc., and Standard Bank PLC.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.34	Amended and Restated Credit Agreement, dated as of August 24, 2009, by and among Gran Tierra Energy Inc., Gran Tierra Energy Colombia, Ltd., Argosy Energy, LLC, Solana Petroleum Exploration (Colombia) Limited, Solana Resources Limited, and Standard Bank PLC.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.35	First Priority Open Pledge Agreement over Credit Rights Derived from Hydrocarbon Commercial Sales Agreements, dated as of August 24, 2009, by and between Solana Petroleum Exploration (Colombia) Limited and Standard Bank PLC.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.36	First Priority Open Pledge Agreement over a Commercial Establishment, dated as of August 24, 2009, by and between Solana Petroleum Exploration (Colombia) Limited and Standard Bank PLC.	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.37	Amended and Restated First Priority Open Pledge Agreement over Credit Rights Derived from Crude Oil Commercial Sales Agreements, dated as of August 24, 2009, by and between Gran Tierra Energy Colombia, Ltd., and Standard Bank PLC.	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.38	Cancellation of BNP Pledge over Credit Rights, dated as of August 20, 2009, by BNP Paribas.	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.39	Cancellation of BNP Pledge over Commercial Establishment, dated as of August 21, 2009, by BNP Paribas.	Incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.40		

	Collection Account Pledge Agreement, dated as of August 24, 2009, by and between Solana Petroleum Exploration (Colombia) Limited and Standard Bank PLC.	Incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.41	Deposit Account Control Agreement, dated as of August 24, 2009, by and among Solana Petroleum Exploration (Colombia) Limited, BNP Paribas, and Standard Bank PLC.	Incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.42	Letter regarding Pledge Agreements, dated as of August 24, 2009, by and among the Gran Tierra Energy Cayman Islands Inc, Gran Tierra Energy Colombia, Ltd., Argosy Energy, LLC, GTE Colombia Holdings LLC, and Standard Bank PLC.	Incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).
10.43	Release of Share Pledge Agreement, dated as of August 24, 2009, by and between Gran Tierra Energy Inc. and Standard Bank PLC.	Incorporated by reference to Exhibit 10.11 to the Quarterly Report on Form 10-Q/A, filed with the SEC on January 6, 2010 (File No. 001-34018).

10.44	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).
10.45	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).
10.46	Second Amendment to Credit Agreement, dated as of November 5, 2010, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders	Filed herewith.
10.47	Third Amendment to Credit Agreement, dated as of January 20, 2011, among Solana Resources Limited, Gran Tierra Energy Inc., BNP Paribas and Other Lenders	Filed herewith.
10.48	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).
10.49	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).
10.50	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.	Filed herewith.
10.51	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.	Filed herewith.
10.52	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	Filed herewith.

	Block	
10.53	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.	Filed herewith.
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 Argentine and Colombian Oil and Gas Properties Corporate Summary, effective December 31, 2010	Filed herewith.

* Management contract or compensatory plan or arrangement.