GRAN TIERRA ENERGY | 2021 Annual Report

GranTierra Energy

MESSAGE FROM THE PRESIDENT & CEO

After the many challenges in 2020 that the world faced, 2021 was a year of strong recovery for the energy industry and Gran Tierra. Our top tier, low-decline, onshore, conventional asset base continued to prove its high quality as the Company returned to strong growth in 2021 in terms of production, reserves, funds flow from operations, free cash flow and after-tax net asset value per share. We achieved strong oil reserve replacement ratios on both a Proved Developed Producing and Total Proved basis driven by our successful, on-budget development programs and waterflood initiatives.

Our teams' excellent work throughout 2021 has strongly positioned Gran Tierra for the continued development and enhanced oil recovery activities in 2022, to optimize value from each of our assets. We see material potential in our exploration portfolio located in highly prospective geological trends in Colombia and Ecuador. Looking to 2022, we are very excited for our planned development drilling programs in the Middle Magdalena Valley and Putumayo Basins in Colombia, and the restart of our exploration drilling program, which we expect to include our first exploration wells in the Oriente basin in Ecuador. In addition to growth through our existing assets in Colombia and Ecuador, we continue to look at opportunities in other select basins to diversify and enhance the Company's future potential for the coming decades. These activities, combined with a more constructive oil price environment, are expected to allow Gran Tierra to continue to resume growth through ongoing development of our existing assets and potential exploration discoveries. Furthermore, in the Company's 2022 guidance, which assumes a Brent oil price of $70-80/bbl, we forecast that Gran Tierra could generate significant 2022 free cash flow, which would allow us to completely pay down our bank credit facility before the end of the first half of 2022.

Finally, our Environmental, Social and Governance ("ESG") focus continues which we achieve through our "Beyond Compliance" philosophy. Where Gran Tierra identifies significant opportunities and benefits to the environment and communities, we voluntarily strive to go beyond what is legally required to protect the environment and provide social benefits, because it is the right thing to do. In 2021, for the first time Gran Tierra reported Scope 2 greenhouse gas ("GHG") emissions (indirect operations from external power sources), in addition to Scope 1 GHG emissions, in the Company's yearly GHG emissions report. Our 2020 results saw an overall GHG emissions reduction in excess of 60% relative to 2019 and which was achieved via the Company's gas-to-power projects and additional operational efficiencies. Gran Tierra is also focused on nature-based solutions to emissions and has planted a total of 1,193,321 trees and has conserved, preserved or reforested 2,805 hectares of land through all our environmental efforts since 2018.

Gary Guidry
President and Chief Executive Officer

*For important definitions, disclaimers and advisories please refer to the 2021 Fourth Quarter and Full Year Results Press Release issued on February 22, 2022.

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

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2021

or

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

For the transition period from __________ to __________

Commission file number **001-34018**

GRAN TIERRA ENERGY INC.

(Exact name of registrant as specified in its charter)

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

900, 520 - 3 Avenue SW

Calgary, Alberta Canada T2P 0R3

(Address of principal executive offices, including zip code)

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

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

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, par value $0.001 per share	GTE	NYSE American
		Toronto Stock Exchange
		London Stock Exchange

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

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

Yes ☐ No ☒

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

Yes ☐ No ☒

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

Indicate by check mark whether the registrant submitted electronically every Interactive Data File required to be submitted 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 such files).

Yes ☒ No ☐

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

Large accelerated filer	☐	Accelerated filer	☒
Non-accelerated filer	☐	Smaller reporting company	☐
		Emerging growth company	☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management’s assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2021, the last business day of the registrant’s most recently completed second fiscal quarter, was approximately $265.4 million.

On February 18, 2022, 367,144,500 shares of the registrant’s Common Stock with $0.001 par value were outstanding.

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 2022 annual meeting of stockholders, which definitive proxy statement will be filed with the Securities and Exchange Commission within 120 days after December 31, 2021.

Auditor Name: KPMG LLP Auditor Location: Calgary, Canada Auditor Firm ID: 85

Gran Tierra Energy Inc.

Annual Report on Form 10-K

Year Ended December 31, 2021

Table of Contents

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts included in this Annual Report on Form 10-K regarding our financial position, estimated quantities and net present values of reserves, business strategy, plans and objectives of our management for future operations, covenant compliance, capital spending plans and benefits of the changes in our capital program or expenditures, our liquidity and financial condition, the impacts of the novel coronavirus (COVID-19) pandemic and those statements preceded by, followed by or that otherwise include the words "believe", "expect", "anticipate", "intend", "estimate", "project", "target", "goal", "plan", "budget", "objective", "should", or similar expressions or variations on these expressions are forward-looking statements. We can give no assurances that the assumptions upon which the forward-looking statements are based will prove to be correct or that, even if correct, intervening circumstances will not occur to cause actual results to be different than expected. Because forward-looking statements are subject to risks and uncertainties, actual results may differ materially from those expressed or implied by the forward-looking statements. There are a number of risks, uncertainties and other important factors that could cause our actual results to differ materially from the forward-looking statements, including, but not limited to, our ability to comply with covenants in our credit agreement and indentures and make borrowings under our credit agreement; a reduction in our borrowing base and our ability to repay any excess borrowings; our ability to extend our revolving credit facility or replace it; sustained or future declines in commodity prices and the demand for oil; continued or future excess supply of oil and natural gas; potential future impairments and reductions in proved reserve quantities and value; continued spread of the COVID-19 virus and extensions of previously announced lockdowns and possible future restrictions against oil and gas activity in Colombia and Ecuador; our operations are located in South America, and unexpected problems can arise due to guerilla activity and other local conditions; technical difficulties and operational difficulties may arise which impact the production, transport or sale of our products; geographic, political and weather conditions can impact the production, transport or sale of our products; our ability to raise capital; our ability to identify and complete successful acquisitions; our ability to execute business plans; unexpected delays and difficulties in developing currently owned properties may occur; the timely receipt of regulatory or other required approvals for our operating activities; the failure of exploratory drilling to result in commercial wells; unexpected delays due to the limited availability of drilling equipment and personnel; current global economic and credit market conditions may impact oil prices and oil consumption differently than we currently predict, which could cause us to further modify our strategy and capital spending program; volatility or declines in the trading price of our common stock and the continued listing of our shares on a national stock exchange; and those factors set out in Part I, Item 1A "Risk Factors" in this Annual Report on Form 10-K. The unprecedented nature of the current pandemic and downturn in the worldwide economy and oil and gas industry makes, including the unpredictable nature of the resurgence of cases and governmental responses, make it more difficult to predict the accuracy of the forward-looking statements. The information included herein is given as of the filing date of this Annual Report on Form 10-K with the Securities and Exchange Commission ("SEC") and, except as otherwise required by the federal securities laws, we disclaim any obligation or undertaking to publicly release any updates or revisions to, or to withdraw, any forward-looking statement contained in this Annual Report on Form 10-K to reflect any change in our expectations with regard thereto or any change in events, conditions or circumstances on which any forward-looking statement is based.

GLOSSARY OF OIL AND GAS TERMS

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

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

Sales volumes represent production NAR adjusted for inventory changes and losses. Our oil and gas reserves are reported NAR. Our production is also reported NAR, except as otherwise specifically noted as *"working interest production before royalties"*. Gas volumes are converted to BOE at the rate of 6 Mcf of gas per bbl of oil, based upon the approximate relative energy content of gas and oil. The rate is not necessarily indicative of the relationship between oil and gas prices. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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

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

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

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

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

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

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

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

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

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

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

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

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

Proved reserves. Those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:
  - (A) The area identified by drilling and limited by fluid contacts, if any, and
  - (B) Adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.

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

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

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

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

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

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

Proved undeveloped reserves. In general, reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. The SEC provides a complete definition of undeveloped oil and gas reserves in Rule 4-10(a)(31) of Regulation S-X.

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

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

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

PART I

Items 1 and 2. *Business and Properties*

General

Gran Tierra Energy Inc., together with its subsidiaries ("Gran Tierra", "the Company", "us", "our", or "we"), is a company focused on international oil and gas exploration and production with assets currently in Colombia and Ecuador. Our Colombian properties represented 98% of our proved reserves NAR at December 31, 2021. For the year ended December 31, 2021, 100% (2020 - 100%) of our revenue was generated in Colombia.

We were incorporated under the laws of the State of Nevada in June 2008 and changed our state of incorporation to the State of Delaware in October 2016.

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

2021 Operational Highlights

During the year ended December 31, 2021, we incurred capital expenditures of $149.9 million, the majority of which were incurred in Colombia. In 2021, we drilled 19 development wells and three water injectors, 19 of which were drilled in the Midas Block and three in the Chaza Block. As at December 31, 2021, 18 of the development wells were producing, and one was in-progress.

One well in-progress in Colombia as at December 31, 2020, was put on production during the first half of 2021.

2022 Outlook

Our Colombian operation represents 100% of our production and approximately 90% of our 2022 capital budget, with the remainder allocated to exploration activities in Ecuador.

The table below shows the break-down of our 2022 capital program:

	Number of Wells (Gross and Net)	2022 Capital Budget ($ million)
Colombia		
Development	20 - 25	160 - 170
Exploration	4	40 -50
Ecuador		
Exploration	2 - 3	20
	26 - 32	220 - 240

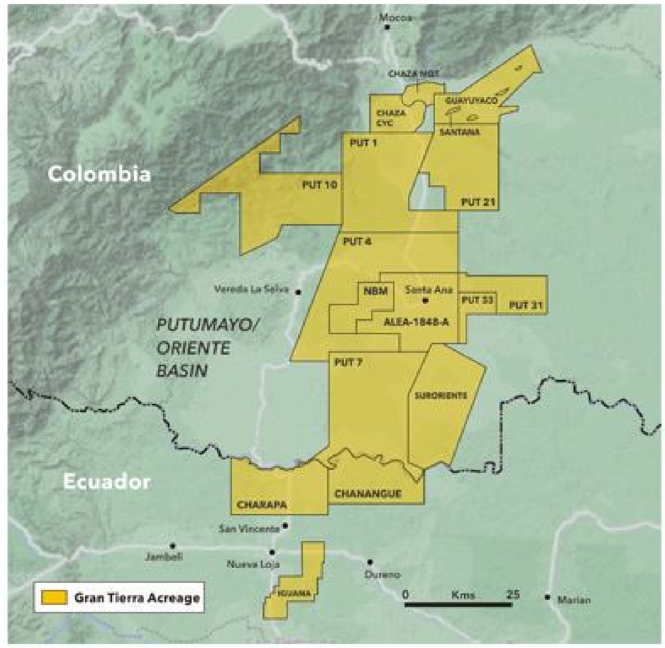
Our base capital program for 2022 is $220 million to $240 million for exploration and development activities. Based on the mid-point of the 2022 guidance, the capital budget is forecasted to be approximately 70% directed to the development and 30% to exploration activities. Approximately 15% of the development activities included in the 2022 capital program are expected to be directed to facilities.

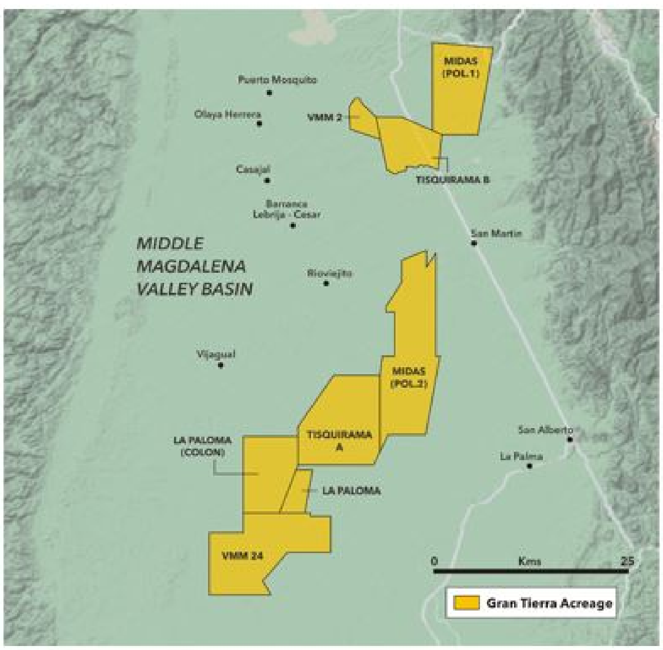
We expect our 2022 capital program to be fully funded by cash flows from operations. Funding this program from cash flow from operations relies in part on Brent oil prices being at least $60 per bbl for 2022.

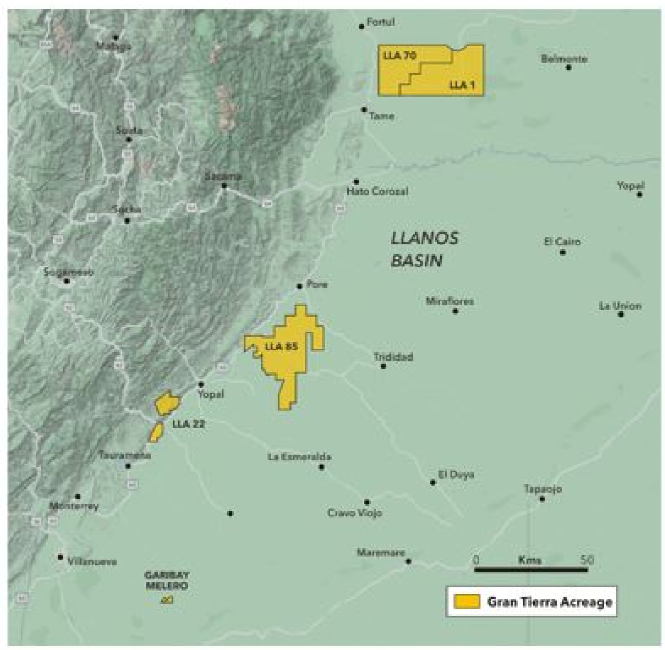
Business Strategy

We are an international exploration and production company focused on hydrocarbon development in proven, under-explored conventional basins which have access to established infrastructure and competitive fiscal regimes. Our mandate is to develop high-value resource opportunities to deliver top-quartile returns. We intend to continue to high-grade our portfolio, with a continued focus on operational excellence, safety, and stakeholder returns. The senior management team has a proven track record in developing technically difficult reservoirs, enhanced oil recovery, and operating in remote locations in demanding jurisdictions. We aim to have a meaningful and sustainable impact through social investments within the communities we operate. Our “Beyond Compliance Policy” focuses on our commitments to environmental, social, and governance excellence.

Oil and Gas Properties - Colombia and Ecuador







As of December 31, 2021, excluding blocks subject to relinquishment, we had interests in 23 blocks in Colombia, three blocks in Ecuador and are the operator of 24 of the blocks.

Exploration Blocks & Commitments

The following table provides a summary of our exploration commitments for certain blocks as of December 31, 2021:

Basin	Block	Current Phase	Remaining Commitments, Current Phase
Colombia			
Putumayo	Alea 1848-A	3 & 4	one exploration well
Putumayo	PUT-1	2*	two exploration wells
Putumayo	PUT-2	2***	three exploration wells
Putumayo	PUT-4	1*	one exploration well
Putumayo	PUT-7	2	two exploration wells
Putumayo	PUT-10	1*	73 km 2D seismic, two exploration wells
Putumayo	PUT-31	1	202 km 2D seismic, one exploration well
Putumayo	NBM	N/A**	two exploration wells
Llanos	LLA-1	1*	98 km^2 3D seismic, one exploration well
Llanos	LLA-22	1 & 2*	85 km^2 3D seismic, one exploration well
Llanos	LLA-70	1*	163 km^2 3D seismic, one exploration well
Llanos	LLA-85	1	50 km^2 3D seismic, 451 km^2 3D seismic reprocessing
MMV	Midas	N/A**	one exploration well
MMV	VMM-24	1	109 km^2 3D seismic, 100 km 2D seismic reprocessing, 100 km aerogeophysics, 100 km^2 remote sensing, 80 km^2 surface geochemistry, one exploration well
Ecuador			
Oriente	Charapa	1	50 km 2D seismic, seven exploration wells
Oriente	Chanangue	1	five exploration wells
Oriente	Iguana	1	two exploration wells

* As of December 31, 2021, exploration has been suspended due to licensing restrictions, security issues or social reasons
** Exploration commitments in exploitation block are not subject to phasing
*** As of December 31, 2021, PUT-2 Block was awaiting approval for relinquishment, at which time the remaining exploration commitments will be transferred to other blocks

Royalties

Colombian royalties are regulated under Colombia Law 756 of 2002, as modified by Law 1530 of 2012. All discoveries made subsequent to the enactment of Law 756 of 2002 have the sliding scale royalty described below. Discoveries made before the enactment of Law 756 of 2002 have a royalty of 20% and in the case of such discoveries under association contracts reverted to the national government, an additional 12% applies for a total royalty of 32%.

The Agencia Nacional de Hidrocarburos (National Hydrocarbons Agency) ("ANH") contracts have royalties that are based on a sliding scale described in Law 756 of 2002. These royalties work on an individual oil Field basis starting with a base royalty rate of 8% for gross production of less than 5,000 bopd, increasing in a linear fashion from 8% to 20% for gross production between 5,000 and 125,000 bopd and is fixed at 20% for gross production between 125,000 and 400,000 bopd. For gross production between 400,000 and 600,000 bopd the rate increases in a linear fashion from 20% to 25%. For gross production in excess of 600,000 bopd the royalty rate is fixed at 25%. The Santana and Nancy-Burdine-Maxine Blocks have a fixed rate for existing production of 32% and 20%, respectively. The sliding scale for new discoveries or incremental production is duly approved by ANH. In addition to the sliding scale royalty, there are additional x-factor economic rights of 1% for Llanos-22, Putumayo-2, Putumayo-4, Putumayo-7, Putumayo-21 and VMM-24; 2% for Llanos-85, 5% for Putumayo-1; 12% for Putumayo-31; 31% for Llanos-1 and Llanos -70.

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

Additional high price rights ("HPR") are applicable to exploration and production contracts signed under the new ANH oil regulatory regime in 2004 and onwards when cumulative gross production (net of royalty) from an Exploitation Area is greater than 5 MMbbls of oil and WTI reference price exceeds the trigger price defined in the contract. The HPR is calculated using the associated production multiplied by the Q factor, which is calculated as follows:

Q factor = (WTI price - Base Price[(1)])/WTI Price * 30%

(1)Base Price is determined annually by the ANH, based on a formula defined in the contract. For 2021 and 2020, the base price was set as follows:

	Year Ended December 31,	
	2021	**2020**
Quality (Oil API)	**(1)Base Price ($/bbl)**	
< 10 º	Nil	Nil
10º to 15º	58.18	57.2
15º to 22º	40.73	40.04
22º to 29º	39.27	38.61
> 29º	37.8	37.16

At December 31, 2021, HPR was applicable to our production from the Costayaco and Moqueta Exploitation Areas in the Chaza Block and the Acordionero Exploitation Area in the Midas Block.

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

The Putumayo-7 and Putumayo-1 Blocks are also subject to a third party royalty in addition to the government royalties and rights. Pursuant to the terms of the agreement by which the interests in the Putumayo-7 Block were acquired, a 10% royalty on production from the Putumayo-7 Block is payable to a third party. The terms of the royalty allow for transportation costs, marketing and handling fees, government royalties (including royalties payable to the ANH pursuant to Section 39 of the contract for the Putumayo-7 Block - the "Rights Due to High Prices") and taxes, other than taxes measured by the income of any party, and other than value-added tax ("VAT") or any equivalent, to be paid in cash or kind to the Government of Colombia (or any federal, state, regional or local government agency) and ANH, and a 1% 'X' factor payment to be deducted from production revenue prior to the royalty being paid to a third party. Pursuant to the terms of the agreement by which the interests in the Putumayo-1 Block were acquired, a 3% royalty on production from the Putumayo-1 Block is payable to a third party. The terms of the royalty do not allow for any costs, royalties, and taxes to be deducted from production revenue.

Administrative Facilities

Our principal executive office is located in Calgary, Alberta, Canada. The Calgary office lease will expire on November 29, 2022. Subsequent to year-end, we signed a six-year agreement for a new Calgary office lease commencing June 1, 2022. Office leases in Colombia and Ecuador will expire on August 31, 2023, and June 30, 2025, respectively.

Estimated Reserves

Our 2021 reserves were independently prepared by McDaniel & Associates ("McDaniel"). McDaniel & Associates was established in 1955 as an independent Canadian consulting firm and has been providing oil and gas reserves evaluation services to the world's petroleum industry for the past 60 years. They have internationally recognized expertise in reserves evaluations, resource assessments, geological studies, and acquisition and disposition advisory services. McDaniel's office is located in Calgary, Canada. The technical person primarily responsible for the preparation of our reserves estimates at McDaniel meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

The primary internal technical person in charge of overseeing the preparation of our reserve estimates is the Vice President, Asset Management. He has a Bachelor of Geological Engineering, graduating with Great Distinction, and a Masters of Chemical Engineering (petroleum). He is responsible for our engineering activities, including reserves reporting, asset evaluation, reservoir management, and Field development. He has over 30 years of experience in the oil and gas industry with extensive experience in reservoir management, production, and operations.

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

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

Proved reserves are reserves which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed technologies that have been demonstrated to yield results with consistency and repeatability. Estimates of proved reserves are generated through the integration of relevant geological, engineering, and production data, utilizing technologies that have been demonstrated in the Field to yield repeatable and consistent results as defined in the SEC regulations. Data used in these integrated assessments included information obtained directly from the subsurface through wellbores, such as well logs, reservoir core samples, fluid samples, static and dynamic pressure information, production test data, and surveillance and performance information. The data utilized also included subsurface information obtained through indirect measurements, such as seismic data. The tools used to interpret the data included proprietary and commercially available seismic processing software and commercially available reservoir modeling and simulation software. Reservoir parameters from analogous reservoirs were used to increase the quality of and confidence in the reserves estimates when available. The method or combination of methods used to estimate the reserves of each reservoir was based on the unique circumstances of each reservoir and the dataset available at the time of the estimate. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. The probable reserves that have been assigned as of December 31, 2021, were based on both the greater percentage of recovery of the hydrocarbons in place than assumed for proved reserves, as well as the areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain.

Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes, and other factors. The possible reserves that have been assigned as of December 31, 2021, were based on both the greater percentage of recovery of the hydrocarbons in place than assumed for probable reserves as well as to areas of a reservoir adjacent to probable reserves where data control or interpretations of available data are less certain.

The following table sets forth our estimated reserves NAR as of December 31, 2021:

Reserves Category	Oil (Mbbl)	Natural Gas (MMcf)	Oil and Natural Gas (MBOE)
Proved			
Total proved developed reserves	41,869	880	42,016
Total proved undeveloped reserves[2]	24,696	789	24,828
Total proved reserves	66,565	1,669	66,844
Probable [1]			
Total probable developed reserves	12,984	133	13,006
Total probable undeveloped reserves	23,359	637	23,465
Total probable reserves	36,343	770	36,471
Possible [1]			
Total possible developed reserves	12,578	94	12,594
Total possible undeveloped reserves	18,057	565	18,151
Total possible reserves	30,635	659	30,745

[1] Estimates of probable and possible reserves are more uncertain than proved reserves, but have not been adjusted for risk due to that uncertainty. Accordingly, estimates of probable and possible reserves are not comparable and have not been, or should not be, summed arithmetically with each other or with estimates of proved reserves.
[2] Total proved undeveloped, probable undeveloped and possible undeveloped reserves include 0.5, 0.9 and 2.3 MMbbl, respectively, of oil reserves related to Ecuador.

Product Prices Used In Reserves Estimates

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

Oil ($/bbl) - Colombia	$	58.07
Natural Gas ($/Mcf) - Colombia	$	3.67
Oil ($/bbl) - Ecuador	$	62.42
ICE Brent - average of the first day of each month price for the 12-month period	$	68.92

These prices should not be interpreted as a prediction of future prices. We do not represent that this data is the fair value of our oil and gas properties or a fair estimate of the present value of cash flows to be obtained from their development and production.

Proved Undeveloped Reserves

At December 31, 2021, we had total proved undeveloped reserves NAR of 24.8 MMBOE (December 31, 2020 - 26.2 MMBOE), which were 98% in Colombia, with the remainder in Ecuador (December 31, 2020 – 100% in Colombia). Approximately 48%, 12%, 15%, and 5% for a total of 80% of proved undeveloped reserves are located in our Acordionero, Costayaco, Moqueta, and Cohembi Fields, respectively, in Colombia. None of our proved undeveloped reserves at

December 31, 2021 have remained undeveloped for five years or more since initial disclosure as proved reserves, and we have adopted a development plan which indicates that the proved undeveloped reserves are scheduled to be drilled within five years of initial disclosure as proved reserves.

Changes in proved undeveloped reserves during the year ended December 31, 2021 are shown in the table below:

	Total Company - Oil Equivalent (MMBOE)
Balance, December 31, 2020	26.2
Converted to proved producing	(7.2)
Technical revisions	(3.8)
Discoveries and extensions	7.5
Improved recovery	2.1
Balance, December 31, 2021	24.8

Changes in proved undeveloped reserves during the year ended December 31, 2021 shown in the table above primarily resulted from the following significant factors:

Converted to Proved Producing. In 2021, we converted 7.2 MMBOE, or 27% of 2020 proved undeveloped reserves to developed status (6.0 MMBOE in Acordionero and 1.2 MMBOE in Costayaco). In 2021, we made investments consisting solely of capital expenditures of $49.2 million in Colombia associated with drilling 22 wells, 19 of which were drilled in the Midas Block and three in the Chaza Block.

Technical and Economic Revisions. During the year ended December 31, 2021, we revised down 3.8 MMBOE of proved undeveloped reserves in Colombia due to halting the planned drilling of undeveloped locations in the Suroriente block prior to the expiration of the lease, along with converting lower than forecasted volumes from the undeveloped pool for Acordionero Field.

Discoveries and Extensions. We added 7.5 MMBOE to proved undeveloped reserves during the year ended December 31, 2021, which were attributed to extensions of 3.7 MMBOE in the Acordionero Field, 2.1 MMBOE in the Costayaco Field, 1.2 MMBOE in the Moqueta Field and 0.5 MMBOE in the Charapa Field in Ecuador.

Improved Recoveries. We added 2.1 MMBOE to proved undeveloped reserves during the year ended December 31, 2021, which were attributed to better recoveries of heavy oil in the Acordionero Field.

Production, Revenue and Price History

Certain information concerning production, prices, revenues, and operating expenses for the years ended December 31, 2021, 2020, and 2019 is set forth in Item 7 “Management's Discussion and Analysis of Financial Condition and Results of Operations” and in the “Supplementary Data (Unaudited)” provided following our Financial Statements in Item 8, which information is incorporated by reference here.

The following table presents NAR oil production, average sales prices, and operating expenses per NAR oil production from our major Fields Acordionero, Costayaco, Moqueta, Cohembi and from all of our properties for the three years ended December 31, 2021, 2020, and 2019, respectively:

	Acordionero [(1)]		Costayaco [(1)]		Moqueta [(1)]		Cohembi [(1)]		Total for all properties [(2)]	
Year Ended December 31, 2021										
Oil production NAR bbl		**4,183,773**		**1,435,434**		**605,926**		**797,196**		**7,879,794**
Average sales price of oil per bbl	**$**	**62.17**	**$**	**59.93**	**$**	**58.80**	**$**	**55.01**	**$**	**60.12**
Operating expenses of oil per bbl [(3)]	**$**	**12.95**	**$**	**19.60**	**$**	**24.50**	**$**	**19.59**	**$**	**18.23**
Year Ended December 31, 2020										
Oil production NAR bbl		3,612,338		1,773,723		792,011		438,799		7,346,200
Average sales price of oil per bbl	$	32.45	$	32.07	$	31.52	$	32.32	$	32.38
Operating expenses of oil per bbl [(3)]	$	12.19	$	17.63	$	17.71	$	15.60	$	16.67
Year Ended December 31, 2019										
Oil production NAR bbl		5,166,430		1,966,585		1,022,391		675,086		10,590,137
Average sales price of oil per bbl	$	54.17	$	56.38	$	55.93	$	54.35	$	53.92
Operating expenses of oil per bbl [(3)]	$	14.60	$	18.95	$	18.88	$	23.94	$	19.23

(1) 100% of product sales were oil
(2) Includes de minimis natural gas production from non-core properties from Colombia of 119,046 Mcf (19,841 boe), 214,719 Mcf (35,787 boe) and 361,065 Mcf (60,178 boe) for each of the years ended December 31, 2021, 2020, and 2019, respectively
(3) Operating expenses include operating and transportation expenses

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

Drilling Activities

The following table summarizes the results of our exploration and development drilling activity for the past three years. Wells labeled as "In Progress" for a year were in progress as of December 31, 2021, 2020, or 2019. This information should not be considered indicative of future performance, nor should it be assumed that there was any correlation between the number of productive wells drilled and the oil and gas reserves generated thereby or the costs to Gran Tierra of productive wells compared to the costs of dry holes.

	2021	2020	2019	
	Gross and Net	Gross and Net	Gross	Net
Exploration				
Productive	**—**	—	3.00	2.50
Dry	**—**	—	1.00	1.00
In progress	**—**	—	2.00	2.00
Development				
Productive	**18.00**	6.00	22.00	22.00
Dry	**—**	—	2.00	2.00
In progress	**1.00**	1.00	1.00	1.00
Service				
Water injectors	**3.00**	1.00	5.00	5.00
Total Colombia	**22.00**	8.00	36.00	35.50

One well in-progress in Colombia as at December 31, 2020, was put on production during the first half of 2021. In 2021, we continued work on power reliability and expansion infrastructure in the Acordionero and Cohembi Fields.

Well Statistics

The following table sets forth our productive wells as of December 31, 2021:

	Oil Wells	
	Gross	Net
Colombia [1]	246.0	208.5
	246.0	208.5

[1] Includes 48.0 gross and 43.0 net water and gas injector wells and 86.0 gross and 83.1 net wells with multiple completions.

We commenced the execution of our 2022 capital program, as planned, and as of February 18, 2022, have commenced drilling a development well in Acordionero.

Developed and Undeveloped Acreage

At December 31, 2021, our acreage was located 91% in Colombia and 9% in Ecuador. The following table sets forth our developed and undeveloped oil and gas lease and mineral acreage as of December 31, 2021:

	Developed		Undeveloped [2]		Total	
	Gross	Net	Gross	Net	Gross	Net
Colombia [1]	312,909	220,520	1,155,538	1,145,993	1,468,447	1,366,513
Ecuador	—	—	138,239	138,239	138,239	138,239
Total	312,909	220,520	1,293,777	1,284,232	1,606,686	1,504,752

[1] Excludes our interest in five blocks with a total of 0.5 million net acres for which government approval of relinquishment or sale was pending at December 31, 2021.
[2] As of December 31, 2021, the exploration phase for 0.2 million gross and net undeveloped acres expires within the next three years, with an option to extend the exploration phase for 50% of the expired area.

Marketing and Major Customers

Colombia represents 100% of our production with oil reserves and production mainly located in the Middle Magdalena Valley ("MMV") and Putumayo Basin. In MMV, our largest Field is the Acordionero Field, where we produce approximately 17° API oil, which represented 53% of total Company production in 2021. The Putumayo production is approximately 27° API for Chaza Block and 18° API for Suoriente Block, representing 37% of total Company production in 2021.

We have entered into numerous sales agreements for our production from MMV and the Putumayo Basin with domestic and international customers. These agreements are subject to renegotiation terms between three and twelve months and generally contain mutual termination provisions with 90 days' notice. The volume of crude oil contemplated in these sales agreements does not include the volume of oil corresponding to royalties taken in kind but does include volumes relating to HPR royalties.

The majority of our Putumayo production is sold at the wellhead. The oil is picked up by customers at Company-operated truck loading stations located at our Costayaco battery or Santana station facilities in Putumayo North and at our Cohembi and Cumplidor Fields in Putumayo South. Production from the Acordionero Field in MMV is trucked and sold at various terminals or pipeline inlets and various distances from the Acordionero Field, depending on the applicable sales agreement. Production from MMV minor Fields is sold at wellhead.

In 2021, approximately 71% of our Putumayo production and 100% of our MMV production was sold to two international marketers. The sales agreements for Putumayo production expire on December 31, 2021 and June 30, 2023. The sales agreement for MMV production expires June 30, 2022. The loss of each individual sales customer will not have a material adverse impact on our Company as customers can be substituted.

We receive revenues for our Colombian oil sales in U.S. dollars. Oil prices for sales of our crude oil are defined by agreements with the purchasers of the oil. They are based generally on an average price for crude oil, referenced to ICE Brent, with adjustments for differences in quality, specified fees, transportation fees, and transportation tax. Pipeline tariffs are denominated in U.S. dollars, and trucking costs are in Colombian Pesos.

Competition

The oil and gas industry is highly competitive. We face competition from both local and multinational companies. This competition impacts our ability to acquire properties, contract drilling and other oil Field equipment, and secure trained personnel. Many competitors, such as Colombia's and Ecuador's national oil companies, have greater financial and technical resources. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which could adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. There is substantial competition for land contracts, prospects, and resources in the oil and natural gas industry, and we compete to develop and produce those reserves cost-effectively. In addition, we compete to monetize our oil production: for transportation capacity and infrastructure to deliver our products, maintain a skilled workforce, and obtain quality services and materials.

Geographic Information

Based on the geographic organization, Colombia is the only reportable segment. During 2019, we signed participation contracts for three blocks in Ecuador. As at and for the years ended December 31, 2021, and 2020, the Ecuador business unit was not significant and was included in our Colombia reportable segment. Long-lived assets are Property, Plant and Equipment, which include all oil and gas assets, furniture and fixtures, automobiles, computer equipment, and capitalized leases. No long-lived assets are held in our country of domicile, which is the United States of America. Assets held by our corporate head office in Calgary, Alberta, Canada, were not significant as of December 31, 2021, and 2020 and were included in the Colombia reportable segment under "other" category. Because all of our exploration and development operations are in Colombia and Ecuador, we face many risks associated with these operations. See Item 1A "Risk Factors" for risks associated with our foreign operations.

Regulation

The oil and gas industry in both Colombia and Ecuador is heavily regulated. Rights and obligations with regard to exploration, development, and production activities are explicit for each project; economics is 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 an opportunity for extension.

Colombia Administration

We operate in Colombia through Colombian branches of the following entities: Gran Tierra Energy Colombia LLC, Gran Tierra Colombia Inc. and Gran Tierra Energy Resources Inc. Gran Tierra Energy Colombia LLC, and Gran Tierra Colombia Inc. are currently qualified as operators of oil and gas properties by the ANH. The entities operate under a special regime for hydrocarbon companies in Colombia that entitle them to collect proceeds from oil sales abroad in US dollars.

In Colombia, the ANH is the administrator of the hydrocarbons in the country and therefore is responsible for the administration of Colombian oil and gas contracts and managing all exploration lands. Ecopetrol, the Colombian national oil company, is a public company listed in the Colombian and United States stock markets, owned in majority by the state with the main purpose of exploring and producing hydrocarbons similar to any other integrated oil company. In addition, Ecopetrol is a major purchaser and marketer of oil in Colombia and directly or through its subsidiaries operates most of the oil transportation and refining infrastructure in the country. Ecopetrol Group also owns a majority stake in the Colombian energy transmission sector.

The ANH uses various forms of contracts, which provide full risk/reward benefits for the contractor. Under the terms of these contracts, the operator retains the right to produce all reserves, production, and income from any new exploration and evaluation block, subject to existing royalty and tax regulations. Each contract contains an exploration period and a production period. The exploration period contains a number of exploration phases, and each phase has an associated work commitment. The production period lasts a number of years (usually 24) from the declaration of a commercial hydrocarbon discovery. Such contracts may be terminated at election of the ANH on the failure of the contract holder to comply with certain material terms of the contract, such as failure to perform committed exploration operations or investments in accordance with the contract. Ecopetrol uses various forms of contracts, which contain exploration and development phases. Duration of contracts can be life of Field or up to a specific date and the terms of such contracts vary depending on the type of contract. Under an Ecopetrol contract, the partner retains its working interest rights to produce all reserves, production and income from any new exploration and evaluation block, subject to existing royalty and tax regulations during the duration of such contracts.

When operating under an ANH contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, except for royalty volumes which are collected by the ANH (or its designee). 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. Under an Ecopetrol contract, each party owns its working interest of the hydrocarbons extracted.

The contracts in place with ANH and Ecopetrol are agreements among both parties duly protected by regulation and therefore cannot be at election of Government, unilaterally adjusted. Contracts include the instances for remediation, arbitration and other protection measures. In addition, investment protection treaties and Colombia regulation protect the sanctity of existing contracts.

Ecuador Administration

We operate in Ecuador through the Ecuadorian branch of Gran Tierra Energy Colombia, LLC.

In Ecuador, the Ministry of Energy and Non-Renewable Natural Resources ("MERNNR", for its acronym in Spanish) is responsible for signing the oil and gas contracts and regulating the Ecuadorian oil and gas industry through the Agency for Regulation and Control of Energy and Non-Renewable Natural Resources.

The MERNNR uses service and participation contracts for the exploration and/or exploitation of hydrocarbons ("Participation Contracts"). We currently hold three Participation Contracts which provide for full risk for the contractor and production sharing with the MERNNR and contain an exploration period and an exploitation period. The exploration period has an associated work commitment and lasts typically 4 years. The Participation Contracts include a provision to extend the exploration period for up to two years, on the grounds of, among others, delays caused by the Ecuadorian government in the environmental licensing procedures. In the second quarter of 2021, we received a two-year extension of the exploration period for all three Participation Contracts, under the aforementioned provision. The exploitation period lasts usually 20 years from the approval of the development plan for one of several commercial hydrocarbon discoveries. Such contracts may be terminated at the election of the MERNNR on the failure of the contract holder to comply with certain material terms of the contract, such as failure to perform committed exploration operations in accordance with the contract.

When operating under a Participation Contract, the contractor is the owner of the hydrocarbons extracted from the contract area during the performance of operations, except for the share of volumes owned by the MERNNR agreed under each contract.

Environmental Compliance

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

We have implemented a company wide web-based reporting system which allows us to track incidents and respective corrective actions and associated costs. We have a Corporate Health, Safety, and Environmental Management Policy and Plan as well as a Corporate Environmental Management Plan ("EMP"). The EMP is based on the environmental performance standards of the

World Bank/IFC and reflects best industry practices. We have an Environmental Management System which is ISO14001:2015 certified representing compliance with internationally recognized industry best practice, as well as an environmental risk management program and robust waste management procedures. Air, soil and water testing occurs regularly and environmental contingency plans have been prepared for all sites and transportation of oil. We have a regular quarterly reporting system, reporting to executive management as well as an Health Safety and Environment Committee of the Board of Directors. We have a schedule of internal and external audits and routine checking of practices and procedures and conduct emergency response exercises.

At December 31, 2021, we had completed a total of 25.3 hectares of environmental clean-up in the Suroriente Block. The environmental clean-up is associated with the oil spills caused by illegal groups in the area in 2013. No clean-up activities were incurred for the year ended December 31, 2021.

Human Capital Management

At December 31, 2021, we had 319 full-time employees (December 31, 2020 - 322): 90 located in the Calgary corporate office, 228 in Colombia (156 staff in Bogota and 72 Field personnel), and one in Ecuador (Quito). None of our employees are represented by labor unions, and we consider our employee relations to be good.

Health and Safety

Safety is our number one priority, and we have implemented safety management systems, procedures, and tools to protect our employees and contractors. As part of our Health and Safety Management System, we identify potential risks associated with the workplace and develop measures to mitigate possible hazards. We support our employees with general safety training and implement specific programs for those working in all our operations, such as equipment and machinery safety, chemical management, and electrical safety. We also have taken additional measures during the COVID-19 pandemic by providing extensive testing, face masks, personal sanitation kits, and frequent disinfection of our facilities and equipment.

Workplace Practices and Policies

Gran Tierra Energy is an equal opportunity employer committed to equality and sourcing local employees, contractors, and suppliers. The company has a program to increase gender and diversity representation, including guidelines to prevent gender discrimination in selection and recruitment by contractors, incentives to promote the recruitment of women throughout the supply chain, training to increase the competitiveness of female employees and candidates, and guarantees of fair working conditions including schedules and salaries.

We are committed to enabling employees and contractors to grow within their roles to advance by offering coaching and mentoring programs. An example of this is our Te Enseña (Learn with Gran Tierra) program. It involves independent training sessions across several departments, where participants improve internal knowledge and further develop their skill sets. Gran Tierra also offers employee-led virtual training sessions that promote individual growth and create a space to learn from their peers. These programs have fostered interdepartmental connections between employees and contractors providing ability to work remotely.

Compensation

We believe all that employees deserve competitive compensation and standard short and long-term incentives that enable employees to share success of the company.

Engagement

The company believes that open, honest, and transparent communication among the team members, managers, and senior management promotes company engagement and offers a strong understanding of our business's big picture. We regularly encourage employees to learn about the organization's strategic objectives and understand company's decisions and how those decisions impact them specifically. We undertake quarterly reviews to inform our team about the company's performance and future goals. We believe these key strategies have led to strategic alignment across the organization.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the Securities and Exchange Commission ("SEC"). We make available free of charge through our website at www.grantierra.com our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed or furnished with the SEC. Our Code of Business Conduct and Ethics, our Corporate Governance Guidelines, our Audit Committee Charter, our Compensation Committee Charter and our Nominating and Corporate Governance Committee Charter are also posted to the governance section of our website. Our website address is provided solely for informational purposes. Information on our website is not incorporated into this Annual Report or otherwise made part of this Annual Report. We intend to use our website as means for distributing information to the public for purposes of compliance with Regulation Fair Disclosure.

In addition, the SEC maintains a website (www.sec.gov) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC, including us.

Item 1A. Risk Factors

Risks Related to our Business

Prices and markets for oil and natural gas are unpredictable and tend to fluctuate significantly, which could cause temporary suspension of production and reduce our value

Substantially all of our revenues are derived from the sale of oil. The current and forward contract oil price is based on world demand, supply, weather, pipeline capacity constraints, inventory storage levels, geopolitical unrest, world health events and other factors, all of which are beyond our control. Historically, the market for oil has been volatile and is expected to remain so. During 2021, global oil and natural gas prices recovered from the historic lows and were scaling multi-year highs due to increased global demand for oil powered by worldwide economic growth as many countries are recovering from COVID-19 pandemic. We expect that oil prices in the near term will continue to be influenced by the duration and severity of the COVID-19 pandemic, as well as related macro-economic developments, such as supply chain and logistics disruptions, and their impact on both oil and natural gas supply and demand. Furthermore, prices which we receive for our oil sales, while based on international oil prices, are established by contracts with purchasers and include the deductions for transportation and quality differentials. The differentials and transportation costs can change over time and have a detrimental impact on realized prices.

Future decreases in the prices of oil, sustained low prices, periods of extended pricing volatility, and increasing borrowing costs may have a material adverse effect on our financial condition, the future results of our operations (including rendering existing projects unprofitable or requiring temporary suspension of Fields), financing available to us, and quantities of reserves recoverable on an economic basis, as well as the market price for our securities.

We may be adversely affected by global epidemics, including the ongoing COVID-19 pandemic

The outbreak of COVID-19 continued throughout 2021 including the spread of the highly transmissible Omicron variant. Worldwide economic climate continued to be volatile making accounting estimates more onerous. Despite the improvement in oil prices in 2021, this volatile economic climate has had and may in the future have significant adverse impacts on our Company including, but not exclusively:

- material declines in revenue and cash flows if commodity prices materially decline;
- extra operating and transportation costs related to COVID-19 health and safety preventative measures including incremental sanitation requirements and enhanced procedures for trucking barrels and crew changes in the field;
- declines in revenue and operating activities due to reduced capital programs and the shut-in of production;
- impairment charges;
- inability to comply with covenants and restrictions in debt agreements;
- inability to access financing sources;
- less capital available as financial institutions encounter investor and political pressure to reduce commitments to the fossil fuel industry;
- increased risk of non-performance by our customers and suppliers;
- supply chain issues;
- higher operating and transportation costs due to increased inflation rates;
- labour shortages; and
- interruptions in operations as we adjust personnel to the dynamic environment.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on our Company is not fully known at this time.

Estimates of oil and natural gas reserves may be inaccurate and our actual revenues may be lower than estimated

We make estimates of oil and natural gas reserves, upon which we base our financial projections and capital expenditure plans. We make these reserve estimates using various assumptions, including assumptions as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Some of these assumptions are inherently subjective, and the accuracy of our reserve estimates relies in part on the ability of our management team, engineers and other advisors to make accurate assumptions. Wells that are drilled may not achieve the results expected. Economic factors beyond our control, such as world oil prices, interest rates, inflation, and exchange rates, will also impact the quantity and value of our reserves.

The process of estimating oil and natural gas reserves is complex, and requires 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 reserves estimates are inherently imprecise. All categories of reserves are continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors. When producing an estimate of the amount of oil that is recoverable from a particular reservoir, probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Possible reserves are even less certain and generally require only a 10% or greater probability of being recovered. Estimates of probable and possible reserves are by their nature much more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk. Actual future production, oil and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from those we estimate. Such changes could materially reduce our revenues and result in the impairment of our oil and natural gas interests.

Unless we are able to replace our reserves and production, and develop and manage oil and natural gas reserves and production on an economically viable basis, our financial condition and results of operations will be adversely impacted

Our future success depends on our ability to find, develop and acquire additional oil and natural gas reserves that are economically recoverable. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. The value of our securities and our ability to raise capital will be adversely impacted if we are not able to replace our reserves that are depleted by production. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production.

Exploration, development and production costs (including operating and transportation costs), marketing costs (including distribution costs) and regulatory compliance costs (including taxes) will substantially impact the net revenues we derive from the oil and natural gas that we produce. These costs are subject to fluctuations and variations in the areas 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.

Our future reserves will depend not only on our ability to develop and effectively manage then-existing properties, but also on our ability to identify and acquire additional suitable producing properties or prospects, to identify and retain responsible service providers and contractors to efficiently drill and complete our wells and to find markets for the oil and natural gas we develop and to effectively distribute our production into our markets.

Exploration for oil and natural gas, and development of new formations, is risky

Oil and natural gas exploration involves a high degree of operational and financial risk. These risks are more acute in the early stages of exploration, appraisal and development. It is difficult to predict the results and project the costs of implementing an exploratory drilling program due to the inherent uncertainties and costs of drilling in unknown formations and encountering various drilling conditions, such as unexpected formations or pressures, premature decline of reservoirs, the invasion of water into producing formations, 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. 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.

Oil and natural gas exploration, development and production operations are subject to the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. Such risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property or the environment, as well as personal injury to our employees, contractors or members of the public.

Losses resulting from the occurrence of any of these risks may have a material adverse effect on our business, financial condition, results of operations and prospects.

Although we maintain well control and liability insurance in an amount that we consider prudent and consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event we could incur significant costs.

Our business is subject to local legal, social, security, political and economic factors that are beyond our control, which could impair or delay our ability to expand our operations or operate profitably

All of our proved reserves and production are currently located in Colombia; however, we may eventually expand to other countries. Exploration and production operations are subject to legal, social, security, political and economic uncertainties, including terrorism, social unrest and activism, illegal blockades, strikes by local or national labor groups, interference with private contract rights, 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. When such disruptions occur, they may adversely impact our operations and threaten the economic viability of our projects or our ability to meet our production targets.

Both Colombia and Ecuador may experience future political and economic instability. Colombia has experienced social, economic and security turmoil related to security, guerilla and narcotrafficking. Political changes because of future electoral processes 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 but not limited to: the imposition of additional taxes; nationalization; changes in energy or environmental policies or the personnel administering them; changes in oil and natural gas pricing policies; and royalty changes or increases. In an extreme case, such a change could result in termination of contract rights and expropriation of foreign-owned assets or renegotiation or nullification of existing concessions and contracts. Any changes in the oil and gas or investment regulations and policies or a shift in political attitudes in Ecuador or Colombia are beyond our control and may significantly hamper our ability to expand our operations or operate our business at a profit. Colombia has investment protection treaties in place with the United States and Canada as well as a history of sanctity of contracts.

Oil production in Ecuador has recently been impacted by outages experienced by the nations two major pipelines (the Sistema de Oleoductos Trans Ecuadoriano (SOTE) and the Oleoducto de Crudos Pesados (OCP) pipelines) caused by physical damage from significant soil erosion in areas along the Coca river. While these pipelines have now been rerouted and are back in service, there remains some risk to GTE’s ability to transport oil to market through these systems from future, unforeseen natural events that could again generate outages in the OCP and SOTE pipelines. Such events could include, but are not limited to, earthquakes, volcanic eruptions and additional significant soil erosion. GTE mitigates this risk through the maintenance of surplus storage capacity at it’s facilities (typically 3-days by design) and the optionality of trucking oil to points of sale.

We are vulnerable to risks associated with geographically concentrated operations

The vast majority of our production comes from four Fields located in Colombia. For the year ended December 31, 2021, the Acordionero, Costayaco, Moqueta and Cohembi Fields collectively generated 89% of our production and at December 31, 2021, these four Fields accounted for 84% of our proved reserves. As a result of this concentration, we may be disproportionately exposed to the impact of, among other things, regional supply and demand factors including limitations on our ability to most profitably sell or market our oil to a smaller pool of potential buyers, delays or interruptions of production from wells in these areas caused by governmental regulation, community protests, guerrilla activities, processing or transportation capacity constraints, continued authorization by the government to explore and drill in these areas, severe weather events and the availability of drilling rigs and related equipment, facilities, personnel or services. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties.

We rely on local infrastructure and the availability of transportation for storage and shipment of our products. This infrastructure, including storage and transportation facilities, is less developed than that in North America and may be insufficient for our needs at commercially acceptable terms in the localities in which we operate. Further, we operate in remote areas and may rely on helicopters, boats or other transportation methods. Some of these transport methods may result in increased levels of risk, including the risk of accidents involving serious injury or loss of life, and could lead to operational delays which could affect our ability to add to our reserve base or produce oil and could have a significant impact on our reputation or cash flow. Additionally, some of this equipment is specialized and may be difficult to obtain in our areas of operations, which could hamper or delay operations, and could increase the cost of those operations. In 2021 we experienced national blockades which have negatively impacted our annual production from major Fields, such as Acordionero, Costayaco, Suroriente, Cumplidor and Moqueta. National blockades have been resolved at the beginning of the fourth quarter of 2021. Additionally, during the fourth quarter of 2021, we experienced localized farmers' blockades directed at the Colombian government, which resulted in the Suroriente and PUT-7 Blocks being temporarily shut-in. These blockades were resolved in November 2021.

Social disruptions or community disputes in our areas of operations may delay production and result in lost revenue

To enjoy the support and trust of local populations and governments, we must demonstrate a commitment to providing local employment, training and business opportunities; a high level of environmental performance; open and transparent communication; and a willingness to discuss and address community issues including community development investments that are carefully selected, not unduly costly and bring lasting social and economic benefits to the community and the area. Improper management of these relationships could lead to a delay or suspension of operations, loss of license or major impact to our reputation in these communities, which could adversely affect our business. We cannot ensure that such issues or disruptions will not be experienced in the future and we cannot predict their potential impacts, which may include delays or loss of production, standby charges, stranded equipment, or damage to our facilities. We also cannot ensure that we will not experience protests or blockades erected by criminal groups or cultivators of illegal crops, in response to the Colombian government's eradication of such crops, if such crops are grown in proximity to roads required to access our operations. In addition, we must comply with legislative requirements for prior consultation with communities and ethnic groups who are affected by our proposed projects in Colombia and Ecuador. Notwithstanding our compliance with these requirements, we may be sued by such communities through a writ for protection of tutela in the Colombian courts for enhanced consultation, potentially leading to increased costs, operational delays and other impacts. In addition, several areas in Colombia have conducted Popular Consultations and essential referendums on extractive industries. The referendums were organized by opponents of the mining or oil and natural gas industries. It remains unclear to what extent such results can impact the exercise of mineral rights conferred by the national government.

Security concerns in Colombia or Ecuador may disrupt our operations

Oil pipelines have historically been primary targets of terrorist activity in Colombia. Although a Peace Agreement was ratified by Colombian government in 2016, the result of which was the demobilization and disarmament of the Revolutionary Armed Forces of Colombia ("FARC"), there continue to be examples of violence against pipelines and other infrastructure that has been attributed to former FARC dissident groups and other illegal groups. It is not currently known whether or to what degree violence will continue and whether and to what degree that violence may impact our operations. Notwithstanding the Peace Agreement ratified and the ongoing efforts to implement such Agreements, increased eradication by the Colombian government of illicit crops, as well as the continuing attempts by the Colombian government to reduce or prevent activity of guerrilla dissidents and of farmers, such efforts may not be successful and such activity may continue to disrupt our operations in the future or cause us higher security costs and could adversely impact our financial condition, results of operations or cash flows.

Colombia and Ecuador have experienced social turmoil related to changes in economic policy, which have resulted in illegal blockades to roads throughout the countries, and illegal invasions to private property and impacting regions where company activities are located. While blockages have been historically directed at the State, the resulting impact may hinder our ability to mobilize oil, personnel and equipment, resulting in temporary shut-in of production or negatively impacting Company assets.

Colombia and Ecuador also both have a history of security problems. Our efforts to ensure the security of our personnel and physical assets may not be successful and there can also be no assurance that we can maintain the safety of our Field personnel or our contractors' Field personnel and our Bogota and Quito head office personnel or operations in Colombia and Ecuador or that this violence will not adversely affect our operations in the future and cause significant loss. If these security problems disrupt our operations, our financial condition and results of operations could be adversely affected.

All of our revenue is generated outside of Canada and the United States, and if we determine to, or are required to, repatriate earnings from foreign jurisdictions, we could be subject to taxes

All of our revenue is generated outside of Canada and the United States. The cash generated from operations abroad is generally not available to fund domestic or head office operations unless funds are repatriated. At this time, we do not intend to repatriate further funds, other than to pay head office charges, but if we did, we might have to accrue and pay withholding taxes in certain jurisdictions on the distribution of accumulated earnings. Undistributed earnings of foreign subsidiaries are considered to be permanently reinvested and a determination of the amount of unrecognized deferred tax liability on these undistributed earnings is not practicable.

The threat and impact of cyberattacks may adversely impact our operations and could result in information theft, data corruption, operational disruption, and/or financial loss

We use digital technologies and software programs to interpret seismic data, manage drilling rigs, conduct reservoir modeling and reserves estimation, as well as to process and record financial and operating data. We depend on digital technology, including information systems and related infrastructure as well as cloud application and services, to store, transmit, process and record sensitive information (including trade secrets, employee information and financial and operating data), communicate with our employees and business partners, analyze seismic and drilling information, estimate quantities of oil and gas reserves and for many other activities related to our business. The complexities of the technologies needed to explore for and develop oil and gas in increasingly difficult physical environments, and global competition for oil and gas resources make certain information attractive to thieves. Our business processes depend on the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure in response to our changing needs and therefore it is critical to our business that our facilities and infrastructure remain secure. While we have implemented strategies to mitigate impacts from these types of events, we cannot guarantee that measures taken to defend against cybersecurity threats will be sufficient for this purpose. The ability of the information technology function to support our business in the event of a security breach or a disaster such as fire or flood and our ability to recover key systems and information from unexpected interruptions cannot be fully tested and there is a risk that, if such an event actually occurs, we may not be able to address immediately the repercussions of the breach or disaster. In that event, key information and systems may be unavailable for a number of days or weeks, leading to our inability to conduct business or perform some business processes in a timely manner. Moreover, if any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial condition or results of operations.

Our employees have been and will continue to be targeted by parties using fraudulent “spoof” and “phishing” emails to misappropriate information or to introduce viruses or other malware through “trojan horse” programs to our computers. These emails appear to be legitimate emails but direct recipients to fake websites operated by the sender of the email or request that the recipient send a password or other confidential information through email or download malware. Despite our efforts to mitigate “spoof” and “phishing” emails through policies and education, “spoof” and “phishing” activities remain a serious problem that may damage our information technology infrastructure.

Risks Related to our Financial Condition

Our business requires significant capital expenditures, and we may not have the resources necessary to fund these expenditures

Our base capital program for 2022 is $220.0 million to $240.0 million for exploration and development activities. We expect to fund our 2022 capital program through cash flows from operations. Funding this program from cash flow from operations relies in part on Brent oil prices being at least $60 per barrel or greater. For the period from January 1 to February 18, 2022, the average price of Brent oil was $88.34 per barrel.

If cash flows from operations, cash on hand and available capacity under our credit facility are not sufficient to fund our capital program, we may be required to seek external financing or to delay or reduce our exploration and development activities, which could impact production, revenues and reserves.

If we require additional capital, we may pursue sources of capital through various financing transactions or arrangements, including joint venturing of projects, debt financing, equity financing or other means. We may not be able to access capital on favorable terms or at all. If we do succeed in raising additional capital, future financings may be dilutive to our shareholders, as we could issue additional shares of common stock or other equity to investors. In addition, debt and other mezzanine financing may involve a pledge of assets, require covenants that would restrict our business activities, 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 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 would adversely impact our financial results.

Our ability to obtain needed financing may be impaired by factors such as weak capital markets (both generally and for the oil and gas industry in particular), the location of our oil and natural gas properties, including in Colombia and Ecuador, low or declining prices of oil and natural gas on the commodities markets, and the loss of key management. Further, if oil 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 flows 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.

Certain sovereign wealth, pension and endowment funds, have promoted the divestment of fossil fuel equities and pressured lenders to cease or limit funding to companies engaged in the extraction of fossil fuel reserves, including recent divestment actions by several prominent New York State and New York public employee pension funds. Such environmental initiatives aimed at targeting climate changes could ultimately interfere with our access to capital and ability to finance our operations.

A failure to meet goals or evolving stakeholder expectations of ESG practices and reporting may potentially harm our reputation and impact employee retention, customer relationships, and access to capital. For example, certain market participants use third party benchmarks or scores to measure a company's ESG practices in making investment decisions and customers and suppliers may evaluate our ESG practices or require that we adopt certain ESG policies as a condition of awarding contracts.

The borrowing base under our revolving credit facility may be reduced by the lenders, which could prevent us from meeting our future capital needs.

The borrowing base under our revolving credit facility is currently $150.0 million, of which $125.0 million is presently eligible for borrowing and $25.0 million is subject to approval by majority lenders. Our borrowing base is redetermined by the lenders twice per year, with the next re-determination to occur no later than May 2022. Our borrowing base may decrease as a result of a decline in oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, lenders willingness to lend to the oil and gas industry, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base, we could be required to repay any indebtedness in excess of the redetermined borrowing base, which would deplete cash flow from operations or require additional financing.

Further, our borrowing base is made available to us subject to the terms and covenants of our revolving credit facility, including compliance with the ratios and other financial covenants of such facility, and a failure to comply with such ratios or covenants could force us to repay a portion of our borrowings and suffer adverse financial impacts. We are required to maintain compliance with the following financial covenants: limitations on the Company's ratio of debt to EBITDAX to a maximum of 4.0; limitations on the Company's ratio of Senior Secured Debt to EBITDAX to a maximum of 3.0; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5.

If we fail to comply with these financial covenants, it would result in a default under the terms of the credit agreement, which could result in an acceleration of repayment of all indebtedness under our revolving credit facility. An event of default under the revolving credit facility would result in a default under the indentures governing our senior notes, which could allow the note holders to require us to repurchase all of our outstanding senior notes. Based on the Brent price and production levels used in 2022 outlook, management expects to be in compliance with the financial covenants contained in the credit facility agreement.

Certain LIBOR benchmarks will no longer be published after December 31, 2021. We expect the LIBOR benchmark to be replaced with risk-free rates. Debt, hedging costs, valuations, and internal financial models are all examples of areas that will be impacted by the transition to alternative reference rates. The transition can potentially impact our intercompany lending, late payment provisions in commercial contacts, structured financing transactions, and other LIBOR referencing contracts outside of our normal banking agreements. The transition of the LIBOR rate to alternative reference rates may potentially increase our lending costs.

Our revolving credit facility matures in November 2022. Capital financing may not be available to us at economic rates.

Our revolving credit facility is scheduled to mature in November 2022. There can be no assurance that financial market conditions or borrowing terms at the time our revolving credit facility is renegotiated will be as favorable as the current terms and interest rates. We may be unable to obtain financing in the future for working capital, capital expenditures, acquisitions, debt service requirements, or other purposes.

Foreign currency exchange rate volatility may affect our financial results

We sell our oil and natural gas production under agreements that are denominated mainly in U.S. dollars. Many of the operational and other expenses we incur, including current and deferred tax assets and liabilities in Colombia, are denominated in Colombian pesos. Most of our administration costs in Canada are incurred in Canadian dollars. As a result, we are exposed to translation risk when local currency financial statements are translated to U.S. dollars, our functional currency. An appreciation of local currencies can increase our costs and negatively impact our results from operations. Because our Consolidated Financial Statements are presented in U.S. dollars, we must translate revenues, expenses and income, as well as assets and liabilities, into U.S. dollars at exchange rates in effect during or at the end of each reporting period. We are also exposed to transaction risk on settlement of payables and receivables denominated in foreign currency.

Legal and Regulatory Risks

We are dependent on obtaining and maintaining permits and licenses from various governmental authorities

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous licenses, permits, approvals and certificates, including environmental and other operating permits. We may not be able to obtain, sustain or renew such licenses and permits on a timely basis or at all. We may also have licenses and permits rescinded or may not be able to renew expiring licenses and permits. Failure or delay in obtaining or maintaining regulatory approvals or permits could have a material adverse effect on our ability to develop and explore on our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. Loss of permits for existing drilling, water injection or other activities necessary for production may result in a decline of our production levels and revenues or damage to the well structure. 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. There can be no assurance that future political conditions in Colombia and Ecuador will not result in changes to policies with respect to foreign development and ownership of oil, environmental protection, health and safety or labor relations, which may negatively affect our ability to undertake exploration and development activities in respect of present and future properties, as well as our ability to raise funds to further such activities.

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.

Environmental regulation and risks may adversely affect our business

Environmental regulation is stringent and the costs and expenses of regulatory compliance are increasing. All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to an extensive suite of international conventions and national and regional laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances used or produced in association with oil and gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal fines and penalties. Our operations create the risk of significant environmental liabilities to the government or third parties for any unlawful discharge of oil, gas or other pollutants into the air, soil or water or for certain other environmental impacts. There is uncertainty around the impact of environmental laws and regulations, including those presently in force and those expected to be proposed in the future. We cannot predict how future environmental laws will be interpreted, administered or enforced, but more stringent laws or regulations or more vigorous enforcement policies could in the future require material expenditures by us for the installation and operation of compliant systems; therefore it is impossible at this time to predict the nature and impact of those requirements on our company however they may have a material adverse impact on our business.

Given the nature of our business, there are inherent risks of oil spills at drilling or operations sites due to operational failure, accidents, sabotage, pipeline failure or tampering or escape of oil due to the transportation of the oil by truck. All of these may lead to significant potential environmental liabilities, such as damages, litigation costs, clean-up costs or penalties, some of which may be material and for which our insurance coverage maybe inadequate or unavailable.

We may be exposed to liabilities under anti-bribery laws and a finding that we violated these laws could have a material adverse effect on our business

We are subject to anti-bribery laws in the United States, Canada, Ecuador and Colombia and will be subject to similar laws in other jurisdictions where we may operate in the future. We may face, directly or indirectly, corrupt demands by officials, tribal or insurgent organizations, international organizations, or private entities. As a result, we face the risk of unauthorized payments or offers of payments by employees, contractors, agents, and partners of ours or our subsidiaries or affiliates, given that these parties are not always subject to our control or direction. It is our policy to prohibit these practices. However, our existing safeguards and any future improvements to those measures may prove to be less than effective or may not be followed, and our employees, contractors, agents, and partners may engage in illegal conduct for which we might be held responsible. A violation of any of these laws, even if prohibited by our policies, may result in criminal or civil sanctions or other penalties (including profit disgorgement) as well as reputational damage and could have a material adverse effect on our business and financial condition.

If the United States imposes sanctions on Colombia or Ecuador in the future, our business may be adversely affected

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 counter-narcotic agreements may result in the imposition of economic and trade sanctions on Colombia which could result in adverse economic consequences in Colombia including potentially threatening our ability to obtain necessary financing to develop our Colombian properties, and could further heighten the political and economic risks associated with our operations there.

Regulations related to emissions and the impact of any changes in climate could adversely impact our business, including demand for our products, our financial condition and results of operations

Governments around the world have become increasingly focused on regulating greenhouse gas ("GHG") emissions and addressing the impacts of climate change in some manner. GHG emissions legislation is emerging and is subject to change. For example, on an international level, in December 2015, almost 200 nations, including Colombia, agreed to an international climate change agreement in Paris, France (the "Paris Agreement"), that calls for countries to set their own GHG emission targets and be transparent about the measures each country will use to achieve its GHG emission targets. Although it is not possible at this time to predict how this legislation or any new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that limit emissions of GHGs could adversely affect demand for the oil and natural gas that we produce. Current GHG emissions legislation has not resulted in material compliance costs; however, emissions, carbon and other regulations impacting climate and climate related matters are constantly evolving. It is not possible at this time to predict whether proposed legislation or regulations will be adopted, and any such future laws and regulations could result in additional compliance costs or additional operating restrictions. If we are unable to recover a significant amount of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse impact on our business, financial condition and results of operations. Significant restrictions on GHG emissions could result in decreased demand for the oil that we produce, with a resulting decrease in the value of our reserves. Further, there have been efforts in recent years to influence the investment community to consider climate change in how they invest in companies. To the extent financial markets view climate change and GHG emissions as a financial risk; this could negatively impact our cost of or access to capital. Increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the company's causation of or contribution to the asserted damage, or to other mitigating factors. Finally, although we strive to operate our business operations to accommodate expected climatic conditions, to the extent there are significant changes in the Earth's climate, such as more severe or frequent weather conditions in the markets we serve or the areas where our assets reside, we could incur increased expenses, our operations could be materially impacted, and demand for our products could fall.

Risks Related to Ownership of our Common Stock

Shares of our Common Stock are listed on the NYSE American, the TSX and the London Stock Exchange ("LSE") and investors seeking to take advantage of price differences between such markets may create unexpected volatility in market prices

Shares of our Common Stock are listed on the NYSE American, the TSX and the LSE. While the Common Stock is traded on such markets, the price and volume levels could fluctuate significantly on any market independently of the price or trading volume on other markets. Investors could seek to sell or purchase shares of Common Stock to take advantage of any price differences between the NYSE American, the TSX and the LSE through a practice referred to as arbitrage. Any arbitrage activity could create unexpected volatility in the price of the Common Stock on any of these exchanges or the volume of Common Stock available for trading on any of these markets. In addition, shareholders in any of these jurisdictions will not be able to transfer such shares of Common Stock for trading on another market without effecting necessary procedures with our transfer agent or registrar. This could result in time delays and additional cost for shareholders of the Common Stock.

If we cannot meet the NYSE American continued listing requirements, the NYSE may delist our shares of Common Stock

Our shares of Common Stock are currently listed on the NYSE American, and the continued listing of our shares is subject to our compliance with a number of listing standards. If we fail to maintain compliance with these continued listing standards, including if the price our shares of Common Stock remains at its current low for a substantial period of time and we fail to effect a reverse stock split upon notice from the NYSE, our shares of Common Stock may be delisted. A delisting of our shares could negatively impact us by, among other things reducing the liquidity of our shares and limiting our ability to issue additional securities, obtain additional financing or pursuant strategic transactions.

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

None.

Item 3. ***Legal Proceedings***

We are engaged in discussions with the ANH regarding the interpretation of whether certain transportation and related costs are eligible to be deducted in the calculation of the HPR royalty. Discussions with the ANH are ongoing. Although the outcome of these discussions cannot be predicted with certainty, we believe the resolution of these matters would not have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flows. The costs are recorded as they incurred or become probable and determinable.

We have several other lawsuits and claims pending. Although the outcome of these lawsuits and disputes cannot be predicted with certainty, we believe the resolution of these matters would not have a material adverse effect on our consolidated financial position, results of operations or cash flows. We record costs as they are incurred or become probable and determinable.

Item 4. ***Mine Safety Disclosures***

Not applicable.

Information About Our Executive Officers

Set forth below is information regarding our executive officers as of February 18, 2022.

Name	Age	Position
Gary S. Guidry	66	President and Chief Executive Officer, Director
Ryan Ellson	46	Chief Financial Officer and Executive Vice President, Finance
James Evans	56	Vice President, Corporate Services
Rodger Trimble	60	Vice President, Investor Relations
Lawrence West	65	Vice President, Exploration

- *Gary S. Guidry, President and Chief Executive Officer, Director.* Mr. Guidry has been Gran Tierra’s Chief Executive Officer and President since May 7, 2015. From July 2011 to July 2014, Mr. Guidry served as President and Chief Executive Officer of Caracal Energy Inc. Mr. Guidry also served as President and CEO of Orion Oil & Gas Corp. from October 2009 to July 2011, Tanganyika Oil Corp. from May 2005 to January 2009, and Calpine Natural Gas Trust from October 2003 to February 2005. As Chief Executive Officer of these companies, Mr. Guidry was responsible for overseeing all aspects of the respective company’s business. Mr. Guidry currently sits on the board of Africa Oil Corp. (since April 2008) where he also serves as a member of the Audit Committee and the board of PetroTal Corp. (since December 2017). From September 2010 to October 2011, Mr. Guidry served on the board of Zodiac Exploration Corp., from October 2009 to March 2014, he served on the board of TransGlobe Energy Corp., and from February 2007 to May

2018, he served on the board of Shamaran Petroleum Corp. Prior to these positions, Mr. Guidry served as Senior Vice President and subsequently President of Alberta Energy Company International, and President and General Manager of Canadian Occidental Petroleum's Nigerian operations. Mr. Guidry has directed exploration and production operations in Yemen, Syria and Egypt and has worked for oil and gas companies around the world in the U.S., Colombia, Ecuador, Venezuela, Argentina and Oman. Mr. Guidry is an Alberta-registered professional engineer (P. Eng.) and holds a B.Sc. in petroleum engineering from Texas A&M University.

- *Ryan Ellson, Chief Financial Officer and Executive Vice President, Finance.* Mr. Ellson has been Gran Tierra's Chief Financial Officer since May 2015. Mr. Ellson has over 22 years of experience in a broad range of international corporate finance and accounting roles. Mr. Ellson is currently a Director of PetroTal Corp. (since December 2017). From July 2014 until December 2014 Mr. Ellson was Head of Finance for Glencore E&P (Canada) Inc. and prior thereto Vice President, Finance at Caracal Energy Inc., a London Stock Exchange ("LSE") listed company with operations in Chad, Africa from August 2011 until July 2014. Glencore E&P (Canada) purchased Caracal in July 2014. Prior to Caracal, Mr. Ellson was Vice President of Finance at Sea Dragon Energy from April 2010 until August 2011. In these positions, Mr. Ellson oversaw financial and accounting functions, implemented and oversaw internal financial controls, secured reserve based lending facility's and was involved in multiple capital raises. Mr. Ellson has held management and executive positions with companies operating in Chad, Egypt, India and Canada. Mr. Ellson is a Chartered Professional Accountant and holds a Bachelor of Commerce and a Master of Professional Accounting from the University of Saskatchewan. Mr. Ellson has completed the Leadership for Senior Executives program at Harvard Business School and several executive education programs at The Wharton School of the University of Pennsylvania.

- *James Evans, Vice President, Corporate Services*. Mr. Evans has been Gran Tierra's Vice President, Corporate Services, since May 2015. Mr. Evans has over 28 years of experience including working the last 17 years in the international oil and gas industry. Most recently, Mr. Evans was the Head of Compliance & Corporate Services for Glencore E&P (Canada) Inc. from July 2014 to December 2014, and prior thereto Vice President of Compliance & Corporate Services at Caracal Energy Inc. from July 2011 to June 2014 where he oversaw the execution of corporate strategy and goals, developed and implemented a robust corporate compliance program, and managed all aspects of IT, document control, security and administration. Mr. Evans also managed the recruitment, training and retention of staff in both Calgary and Chad. He oversaw the growth of Caracal Energy from seven employees to more than 400 at the time of sale to Glencore. Prior to Caracal, Mr. Evans held senior management and executive positions at Orion Oil and Gas and Tanganyika Oil, with operating experience in Egypt, Syria and Canada. Mr. Evans holds a Bachelor of Commerce degree from the University of Calgary.

- *Rodger Trimble, Vice President, Investor Relations*. Mr. Trimble has been Gran Tierra's Vice President, Investor Relations since June 2016. He is a Professional Engineer with more than 38 years of experience in domestic and international basins in various management positions. Prior to joining Gran Tierra, Mr. Trimble was Head of Corporate Planning, Budgeting & Finance with Glencore E&P (Canada) Inc. and prior thereto Director Corporate Planning, Budget & Business Development with Caracal Energy Inc. (acquired by Glencore E&P). He has held several senior management positions ranging from Country Manager in Argentina with Canadian Hunter Exploration, Vice President, Exploitation with Esprit Energy Trust, Manager, Reservoir Engineering with Apache Canada Inc. and Manager, Upstream Evaluations - Frontiers & International with Husky Energy. Mr. Trimble is an Alberta-registered Professional Engineer and a member of APEGA. He received a Bachelor of Science in Petroleum Engineering (with Distinction) from Stanford University.

- *Lawrence West, Vice President, Exploration*. Mr. West has been Gran Tierra's Vice President, Exploration, since May 2015. Mr. West has over 43 years of experience as an executive, explorationist, and geologist. Most recently, Mr. West was Vice President, Exploration at Caracal Energy from July 2011 to June 2014. Mr. West built a multi-disciplinary team to assess resources and grow reserves in the interior rift basins within Chad and led a successful exploration program. During his tenure he successfully executed two large 2D/3D seismic shoots in remote frontier basins, on time and on budget. Prior to Caracal he has been involved in starting and growing several public and private companies, including Reserve Royalty Corp., Chariot Energy, Auriga Energy and Orion Oil and Gas. Lawrence worked at Alberta Energy Company (AEC), where he was on the team that merged with Conwest. He built and led the AEC East team to the Rocky Mountain USA basins. His career began with Imperial Oil working on prospect and reservoir characterization, in multi-disciplinary teams, and as a technical mentor to exploration teams. Lawrence has an Honours Bachelor of Science in Geology from McMaster University and an MBA, specializing in economics, from the University of Calgary.

PART II

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

Shares of our Common Stock trade on the NYSE American, the Toronto Stock Exchange ("TSX") and on the London Stock Exchange ("LSE") under the symbol "GTE".

As of February 18, 2022, there were approximately 31 holders of record of shares of our Common Stock and 367,144,500 shares outstanding with $0.001 par value.

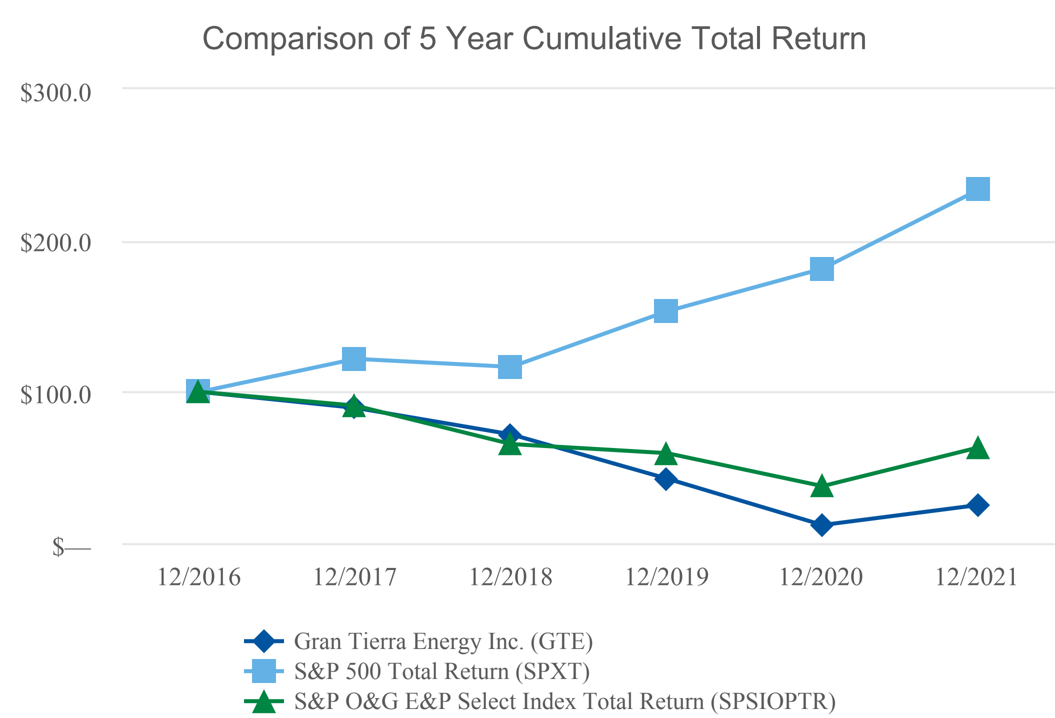
Dividend Policy

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

Performance Graph

The information in this Annual Report on Form 10-K appearing under the heading "Performance Graph" is being "furnished" pursuant to Item 201(e) of Regulation S-K under the securities Act and shall not be deemed to be "soliciting material" or "filed" with the SEC or subject to Regulation 14A or 14C, other than as provided in Item 201(e) of Regulation S-K, or to the liabilities of Section 18 of the Exchange Act and shall not be deemed incorporated by reference into any filing under the Securities Act or the Exchange Act except to the extent that we specifically incorporate it by reference into such filing.

The performance graph below shows the cumulative total shareholder return on our shares of the period starting on December 31, 2016, and ending on December 31, 2021, which was the end of our fiscal 2021 year. This is compared with the cumulative total returns over the same period pf the S&P 500 Total Return Index and the S&P O&G E&P Select Index Total Return. The graph assumes that, on December 31, 2016, $100 was invested in our shares and $100 was invested in each of the other two indices, with dividends reinvested on the ex-dividend date without payment of any commissions. The performance shown in the graph represents past performance and should not considered an indication of future performance.



	12/2016	12/2017	12/2018	12/2019	12/2020	12/2021
Gran Tierra Energy Inc. (GTE)	$ 100.0	$ 89.4	$ 71.9	$ 42.7	$ 12.0	$ 25.2
S&P 500 Total Return (SPXT)	$ 100.0	$ 121.8	$ 116.5	$ 153.2	$ 181.4	$ 233.4
S&P O&G E&P Select Index Total Return	$ 100.0	$ 90.9	$ 65.5	$ 59.5	$ 37.7	$ 63.2

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 and Section 21E of the Exchange Act. Please see the cautionary language at the very beginning of this Annual Report on Form 10-K regarding the identification of and risks relating to forward-looking statements, as well as Part I, Item 1A. "Risk Factors" in this Annual Report on Form 10-K.

The following discussion of our financial condition and results of operations should be read in conjunction with the "Financial Statements and Supplementary Data" as set out in Part II, Item 8 of this Annual Report on Form 10-K. This Management's Discussion and Analysis of Financial Condition and Results of Operations generally discusses items related to the fiscal year ended December 31, 2021 and year-to-year comparisons between the fiscal years ended December 31, 2021 and 2020, respectively. Discussions of items related to the fiscal year ended December 31, 2019 and year-to-year comparisons between the fiscal years ended December 31, 2020 and 2019, respectively, that are not included in this Annual Report on Form 10-K can be found in "Management's Discussion and Analysis of Financial Condition and Results of Operations" in Part II, Item 7 of the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2020.

Overview

We are a company focused on international oil and gas exploration and production with assets currently in Colombia and Ecuador. Our Colombian properties represented 99% of our proved reserves NAR at December 31, 2021. For the year ended December 31, 2021, 100% of our revenue was generated in Colombia (2020 - 100% and 2019 -100%). We are headquartered in Calgary, Alberta, Canada.

As of December 31, 2021, we had estimated proved reserves NAR of 66.8 MMBOE, a 3% increase from the prior year, of which 63% were proved developed reserves and 100% were oil.

Financial and Operational Highlights

Key Highlights

- Net income in 2021 was $42.5 million or $0.12 per share basic and diluted compared to a net loss of $778.0 million, or $(2.12) per share basic and diluted in 2020
- Income before income taxes in 2021 was $23.1 million compared to loss before income taxes of $853.4 million in 2020
- Our total 2021 average production NAR was 21,588 bopd, an increase from 20,072 bopd in 2020 as a result of successful drilling and workover campaigns in Acordionero and Costayaco Fields
- Our total 2021 oil sales volumes NAR increased by 7% to 21,598 bopd compared to 2020
- Oil sales for 2021 increased 99% to $473.7 million compared to $237.8 million in 2020, primarily as a result of a 64% increase in Brent price, a 7% increase in sales volumes, and lower quality and transportation discounts
- Oil sales per bbl for 2021 were $60.09, 86% higher compared to 2020, directly a result of increased benchmark pricing
- Adjusted EBITDA[(2)] for 2021 was $241.5 million compared to $96.5 million in 2020
- In 2021, we generated net cash provided by operating activities of $244.8 million, an increase of 202% from $81.1 million in 2020
- Funds flow from operations[(2)] for 2021 increased by 312% to $186.5 million or $0.51 per share basic and diluted compared with $45.2 million or $0.12 per share basic and diluted in 2020
- During 2021 the Company generated $36.6 million of free cash flow[(2)] which was used for debt reduction
- Operating expenses per bbl for 2021 were $16.79, 11% higher than 2020, primarily due to higher workovers related to electric submersible pump replacements in Acordionero, Costayaco, and Cohembi Fields. In 2020, we shut-in minor

Fields and deferred workovers due to the low price environment caused by COVID-19. Total operating expenses were $132.3 million in 2021, compared to $111.9 million in 2020, representing an 18% increase

- Quality and transportation discounts per bbl for 2021 were $10.86 compared to $10.98 in 2020. The decrease was due to lower Castilla and Vasconia differentials in 2021 as a result of higher demand for heavy oil compared to 2020
- Transportation expenses per bbl for 2021 increased by 1% to $1.44 compared to 2020, primarily due to lower volumes sold at wellhead during 2021
- General and administrative ("G&A") expenses before stock-based compensation per bbl for 2021 increased by 8% to $3.53 compared to 2020 due to performance bonuses in 2021. G&A expense before stock-based compensation was $27.9 million in 2021, compared to $24.1 million in 2020, representing a 15% increase
- Capital expenditures increased by $53.6 million or 56% from the prior year to $149.9 million as a result of lower capital expenditures in 2020 due to curtailed drilling activity and deferred workovers due to the low price environment caused by COVID-19
- On December 21, 2021, we completed the semi-annual redetermination. At our election we reduced the borrowing base to $150.0 million with $125 million presently eligible for borrowing, and $25.0 million is subject to approval by majority lenders. In 2021, we repaid $122.5 million on our revolving credit facility, reducing the balance to $67.5 million as at December 31, 2021
- Through both direct tax refunds from the Colombian government and value-added tax ("VAT") on our oil sales, we collected a total of VAT and income tax receivables of $120.7 million and paid $100.1 million in VAT and income tax, for a net cash inflow of $20.5 million in 2021 compared to $55.4 million net collections in 2020

(Thousands of U.S. Dollars, unless otherwise noted)	**Year Ended December 31,**				
	2021	**% Change**	**2020**	**% Change**	**2019**
SEC Compliant Reserves, NAR (MMBOE)					
Estimated proved oil and gas reserves	**67**	3	65	(4)	68
Estimated probable oil and gas reserves	**36**	(18)	44	(24)	58
Estimated possible oil and gas reserves	**31**	(30)	44	16	38
Average Consolidated Daily Volumes (BOPD)					
Working interest ("WI") production before royalties	**26,507**	17	22,624	(35)	34,817
Royalties	**(4,919)**	93	(2,552)	(56)	(5,802)
Production NAR	**21,588**	8	20,072	(31)	29,015
Decrease in inventory	**10**	(89)	91	(27)	125
Sales [1]	**21,598**	7	20,163	(31)	29,140
Net Income (Loss)	**$ 42,482**	105	$ (777,967)	(2,111)	$ 38,690
Operating Netback					
Oil sales	**$ 473,722**	99	$ 237,838	(58)	$ 570,983
Operating expenses	**(132,331)**	18	(111,888)	(39)	(183,204)
Transportation expenses	**(11,315)**	7	(10,543)	(48)	(20,400)
Operating netback [2]	**$ 330,076**	186	$ 115,407	(69)	$ 367,379
G&A Expenses Before Stock-Based Compensation	**$ 27,867**	15	$ 24,134	(31)	$ 35,071
G&A Stock-Based Compensation	**$ 8,396**	590	$ 1,216	(15)	$ 1,430
Adjusted EBITDA [2]	**$ 241,536**	150	$ 96,482	(71)	$ 329,359
Net Cash Provided By Operating Activities	**$ 244,834**	202	$ 81,074	(54)	$ 177,665
Funds Flow From Operations [2]	**$ 186,485**	312	$ 45,213	(83)	$ 272,409
Capital Expenditures	**$ 149,879**	56	$ 96,281	(75)	$ 379,314
Cash Paid for Acquisitions, Net of Cash Acquired	**$ —**	—	$ —	(100)	$ 77,772

(Thousands of U.S. Dollars)	As at December 31, 2021	% Change	2020	% Change	2019
Cash and cash equivalents and current restricted cash and cash equivalents	**$ 26,501**	88	$ 14,114	60	$ 8,817
Revolving credit facility	**$ 67,500**	(64)	$ 190,000	61	$ 118,000
Senior Notes	**$ 600,000**	—	$ 600,000	—	$ 600,000

(1) Sales volumes represent production NAR adjusted for inventory changes.
(2) Non-GAAP measures

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

Operating netback, as presented, is defined as oil sales less operating and transportation expenses. Management believes that operating netback is a useful supplemental measure for management and investors to analyze financial performance and provides an indication of the results generated by our principal business activities prior to the consideration of other income and expenses. A reconciliation from oil sales to operating netback is provided in the table above.

EBITDA, as presented, is defined as net income or loss adjusted for depletion, depreciation and accretion (“DD&A”) expenses, interest expense, and income tax expense or recovery. Adjusted EBITDA, as presented, is defined as EBITDA adjusted for asset impairment, goodwill impairment, non-cash lease expense, lease payments, unrealized foreign exchange gains or losses, unrealized derivative instruments gains or losses, other financial instruments gains or losses, loss on redemption of Convertible Notes, other non-cash losses, and stock based compensation expense. Management uses this supplemental measure to analyze performance and income generated by our principal business activities prior to the consideration of how non-cash items affect that income and believes that this financial measure is a useful supplemental information for investors to analyze our performance and our financial results. A reconciliation from net income or loss to EBITDA and adjusted EBITDA is as follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2021	2020	2019	Three Months Ended December 31, 2021	2020	September 30, 2021
Net income (loss)	**$ 42,482**	$ (777,967)	$ 38,690	**$ 62,524**	$ (47,871)	$ 35,007
Adjustments to reconcile net income (loss) to EBITDA and Adjusted EBITDA						
DD&A expenses	**139,874**	164,233	225,033	**41,574**	33,115	38,055
Interest expense	**54,381**	54,140	43,268	**13,026**	13,936	13,608
Income tax (recovery) expense	**(19,346)**	(75,394)	57,285	**(46,141)**	(13,158)	8,955
EBITDA (non-GAAP)	**$ 217,391**	$ (634,988)	$ 364,276	$ 70,983	$ (13,978)	$ 95,625
Asset impairment	**—**	564,495	—	**—**	57,402	—
Goodwill impairment	**—**	102,581	—	**—**	—	—
Non-cash lease expense	**1,667**	1,951	1,806	**445**	457	408
Lease payments	**(1,621)**	(1,926)	(1,969)	**(382)**	(522)	(384)
Unrealized foreign exchange loss (gain)	**21,879**	5,271	1,803	**4,934**	(17,064)	3,465
Unrealized derivative instruments (gain) loss	**(9,589)**	8,974	396	**(12,088)**	8,421	(4,729)
Other financial instruments loss (gain)	**3,369**	46,882	(49,884)	**15,794**	(14,404)	(13,634)
Loss on redemption of Convertible Notes	**—**	—	11,501	**—**	—	—
Other non-cash loss	**44**	2,026	—	**44**	—	—
Stock-based compensation expense	**8,396**	1,216	1,430	**1,799**	1,923	1,053
Adjusted EBITDA (non-GAAP)	**$ 241,536**	$ 96,482	$ 329,359	**$ 81,529**	$ 22,235	$ 81,804

Funds flow from operations, as presented, is defined as net income or loss adjusted for DD&A expenses, asset impairment, goodwill impairment, deferred tax expense or recovery, stock-based compensation expense, amortization of debt issuance costs, non-cash lease expense, lease payments, unrealized foreign exchange gains or losses, unrealized derivative instruments gains or losses, loss on redemption of Convertible Notes, other financial instruments gains or losses, and other non-cash losses. Management uses this financial measure to analyze performance and income or loss generated by our principal business activities prior to the consideration of how non-cash items affect that income or loss, and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. Free cash flow, as presented, is defined as funds flow less capital expenditures. Management uses this financial measure to analyze cash flow generated by our principal business activities after capital requirements and believes that this financial measure is also useful supplemental information for investors to analyze performance and our financial results. A reconciliation from net income or loss to funds flow from operations and free cash flow is as follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2021	Year Ended December 31, 2020	Year Ended December 31, 2019	Three Months Ended, December 31, 2021	Three Months Ended, December 31, 2020	Three Months Ended, September 30, 2021
Net income (loss)	**$ 42,482**	$ (777,967)	$ 38,690	**$ 62,524**	$ (47,871)	$ 35,007
Adjustments to reconcile net income (loss) to funds flow from operations						
DD&A expenses	**139,874**	164,233	225,033	**41,574**	33,115	38,055
Asset impairment	**—**	564,495	—	**—**	57,402	—
Goodwill impairment	**—**	102,581	—	**—**	—	—
Deferred tax (recovery) expense	**(23,825)**	(76,148)	40,227	**(50,634)**	(13,352)	8,955
Stock-based compensation expense	**8,396**	1,216	1,430	**1,799**	1,923	1,053
Amortization of debt issuance costs	**3,809**	3,625	3,376	**1,127**	851	907
Non-cash lease expense	**1,667**	1,951	1,806	**445**	457	408
Lease payments	**(1,621)**	(1,926)	(1,969)	**(382)**	(522)	(384)
Unrealized foreign exchange loss (gain)	**21,879**	5,271	1,803	**4,934**	(17,064)	3,465
Unrealized derivative instruments (gain) loss	**(9,589)**	8,974	396	**(12,088)**	8,421	(4,729)
Loss on redemption of Convertible Notes	**—**	—	11,501	**—**	—	—
Other financial instruments loss (gain)	**3,369**	46,882	(49,884)	**15,794**	(14,404)	(13,634)
Other non-cash loss	**44**	2,026	—	**44**	—	—
Funds flow from operations (non-GAAP)	**$ 186,485**	$ 45,213	$ 272,409	**$ 65,137**	$ 8,956	$ 69,103
Capital Expenditures	**$ 149,879**	$ 96,281	$ 379,314	**$ 40,229**	$ 39,903	$ 34,839
Free cash flow (non-GAAP)	**$ 36,606**	$ (51,068)	$ (106,905)	**$ 24,908**	$ (30,947)	$ 34,264

Consolidated Results of Operations

(Thousands of U.S. Dollars)	Year Ended December 31, 2021	% Change	2020	% Change	2019
Oil sales	**$ 473,722**	99	$ 237,838	(58)	$ 570,983
Operating expenses	**132,331**	18	111,888	(39)	183,204
Transportation expenses	**11,315**	7	10,543	(48)	20,400
Operating netback [(1)]	**330,076**	186	115,407	(69)	367,379
COVID-19 related costs	**3,694**	38	2,679	100	—
DD&A expenses	**139,874**	(15)	164,233	(27)	225,033
Asset impairment	**—**	(100)	564,495	100	—
Goodwill Impairment	**—**	(100)	102,581	100	—
G&A expenses before stock-based compensation	**27,867**	15	24,134	(31)	35,071
G&A stock-based compensation expense	**8,396**	590	1,216	(15)	1,430
Foreign exchange loss	**20,477**	389	4,184	567	627
Derivative instruments loss	**48,838**	1,564	2,935	(20)	3,669
Other financial instruments loss (gain)	**3,369**	(93)	48,047	196	(49,884)
Interest expense	**54,381**	—	54,140	25	43,268
	306,896	(68)	968,644	274	259,214

Other loss	**(44)**	(91)	(469)	(96)	(12,886)
Interest income	**—**	(100)	345	(50)	696
Income (loss) before income taxes	**23,136**	103	(853,361)	(989)	95,975
Current income tax expense	**4,479**	494	754	(96)	17,058
Deferred income tax (recovery) expense	**(23,825)**	69	(76,148)	(289)	40,227
Total income tax (recovery) expense	**(19,346)**	74	(75,394)	(232)	57,285
Net income (loss)	**$ 42,482**	105	$ (777,967)	(2,111)	$ 38,690
Sales Volumes (NAR)					
Total sales volumes, BOPD	**21,598**	7	20,163	(31)	29,140
Brent Price per bbl	**$ 70.95**	64	$ 43.21	(33)	$ 64.16
Consolidated Results of Operations per bbl Sales Volumes (NAR)					
Oil sales	**$ 60.09**	86	$ 32.23	(40)	$ 53.68
Operating expenses	**16.79**	11	15.16	(12)	17.23
Transportation expenses	**1.44**	1	1.43	(26)	1.92
Operating netback [(1)]	**41.86**	168	15.64	(55)	34.53
COVID-19 related costs	**0.47**	31	0.36	100	—
DD&A expenses	**17.74**	(20)	22.25	5	21.16
Asset impairment	**—**	(100)	76.49	100	—
Goodwill Impairment	**—**	(100)	13.90	100	—
G&A expenses before stock-based compensation	**3.53**	8	3.27	(1)	3.30
G&A stock-based compensation expense	**1.07**	569	0.16	23	0.13
Foreign exchange loss	**2.60**	356	0.57	850	0.06
Derivative instruments loss	**6.19**	1,448	0.40	18	0.34
Other financial instruments loss (gain)	**0.43**	(93)	6.51	239	(4.69)
Interest expense	**6.90**	(6)	7.34	80	4.07
	38.93	(70)	131.25	439	24.37
Other loss	**(0.01)**	(83)	(0.06)	(95)	(1.21)
Interest income	**—**	(100)	0.05	(29)	0.07
Income (loss) before income taxes	**2.92**	103	(115.62)	(1,382)	9.02
Current income tax expense	**0.57**	470	0.10	(94)	1.60
Deferred income tax (recovery) expense	**(3.02)**	71	(10.32)	(373)	3.78
Total income tax (recovery) expense	**(2.45)**	76	(10.22)	(290)	5.38
Net income (loss)	**$ 5.37**	105	$ (105.40)	(2,996)	$ 3.64

[(1)] Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to “Financial and Operational Highlights - Non-GAAP measures” for a definition and reconciliation of this measure.

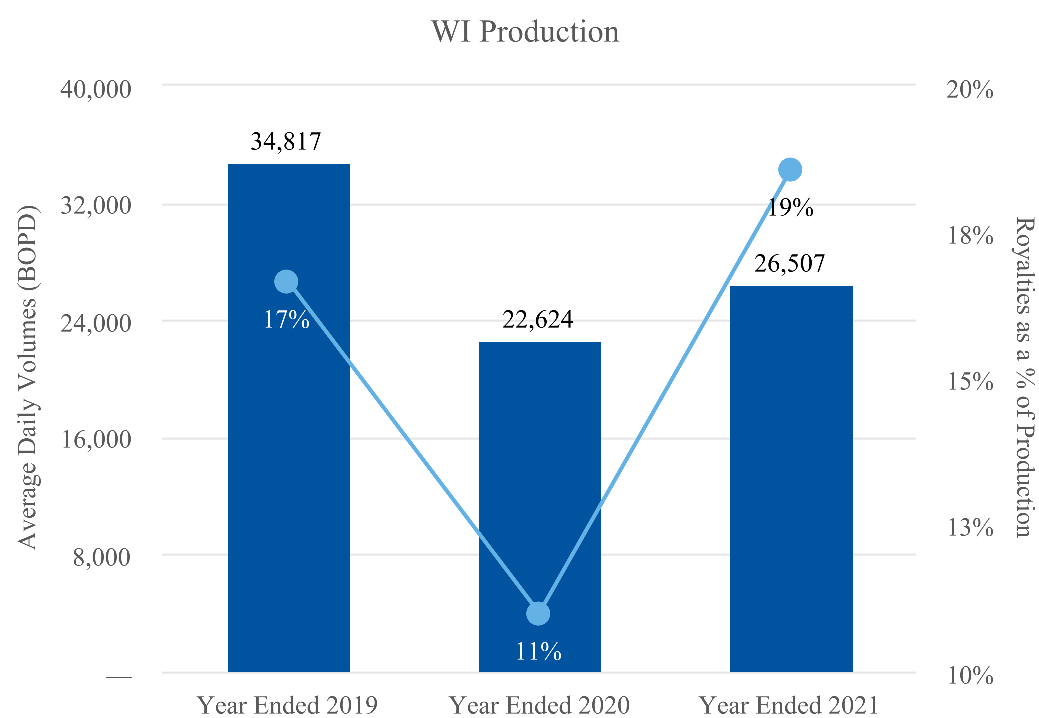
Oil Production and Sales Volumes, BOPD

Average Daily Volumes (BOPD)	Year Ended December 31, 2021	2020	2019
WI production before royalties	**26,507**	22,624	34,817
Royalties	**(4,919)**	(2,552)	(5,802)
Production NAR	**21,588**	20,072	29,015
Decrease in inventory	**10**	91	125
Sales	**21,598**	20,163	29,140
Royalties, % of working interest production before royalties	**19 %**	11 %	17 %

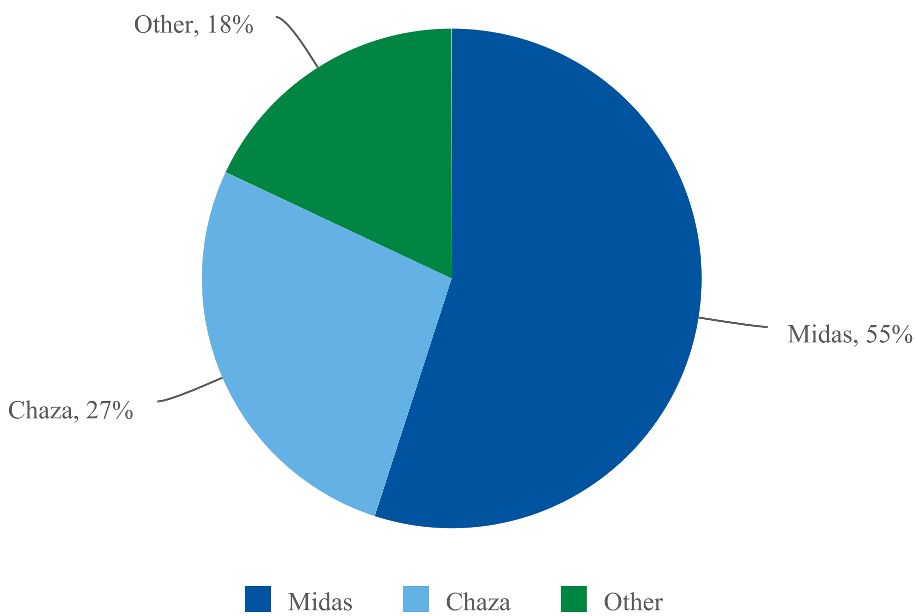
Oil production NAR for the year ended December 31, 2021, increased 8% to 21,588 BOPD from 2020. Production increased as a result of successful drilling and workover campaigns in Acordionero and Costayaco Fields, despite national blockades in the second quarter of 2021 affecting production from major Fields, and a local farmers blockade affecting the Suroriente Block in the fourth quarter of 2021.

Royalties as a percentage of production for the year ended December 31, 2021, increased compared to prior year commensurate with the increase in benchmark oil prices and the price sensitive royalty regime in Colombia.

Oil production NAR for the year ended December 31, 2020, decreased by 31% to 20,072 BOPD compared with 29,015 BOPD in 2019. Production decreased as a result of the COVID-19 pandemic and the related crash in world oil prices. During the first half of 2020, we shut-in minor Fields, curtailed drilling activity, and deferred workovers to protect the Company's balance sheet and liquidity. In the low price environment, we made the prudent move not to maximize but defer production to a higher price environment. In addition, we experienced force majeure related to a local farmer's blockade, which resulted in the shut-in of production at the Suroriente and PUT-7 Blocks for the first half of 2020.



Production By Block, Year Ended December 31, 2021



The Midas Block includes Acordionero, Mochuelo and Ayombero-Chuira Fields and the Chaza Block includes Costayaco and Moqueta Fields.

Oil Sales

Oil sales for the year ended December 31, 2021, increased by 99% to $473.7 million compared to $237.8 million in 2020, primarily as a result of a 64% increase in Brent price, 7% higher sales volumes, and lower quality and transportation discounts in 2021.

Oil sales for the year ended December 31, 2020, decreased by 58% to $237.8 million compared to $571.0 million in 2019, primarily as a result of a 33% decrease in Brent price, 31% lower sales volumes, and higher quality and transportation discounts in 2020.

The following table shows the effect of changes in realized price and sales volumes on our oil sales for the years ended December 31, 2021, 2020, and 2019:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Oil sales for the comparative period	**$ 237,838**	$ 570,983	$ 613,431
Realized sales price increase (decrease) effect	**219,641**	(158,334)	(51,485)
Sales volume increase (decrease) effect	**16,243**	(174,811)	9,037
Oil sales for the current period	**$ 473,722**	$ 237,838	$ 570,983

On a per bbl basis, average realized prices increased by 86% to $60.09 for the year ended December 31, 2021, compared to $32.23 in 2020, primarily as a result of the increase in benchmark oil prices and lower Castilla and Vasconia differentials in 2021. In 2021, Castilla and Vasconia differentials per bbl averaged $5.74 and $3.52 respectively, compared to $6.79 and $4.31 respectively, in 2020.

On a per bbl basis, average realized prices decreased by 40% to $32.23 for the year ended December 31, 2020, compared to $53.68 in 2019, primarily as a result of the decrease in benchmark oil prices and higher Castilla and Vasconia differentials in 2020. In 2020 the Castilla and Vasconia differentials per bbl averaged $6.79 and $4.31 respectively, compared to $5.64 and $2.54 respectively, in 2019.

Transportation Expenses

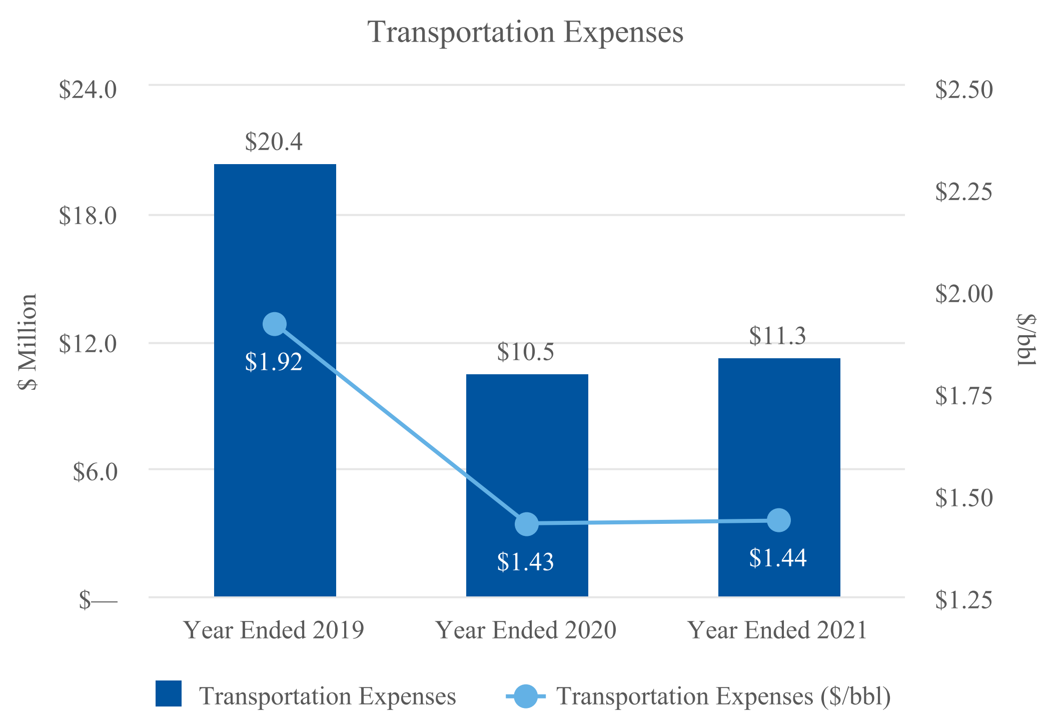
We have options to sell our oil through multiple pipelines and trucking routes. Each transportation route has varying effects on realized price and transportation expenses. The following table shows the percentage of oil volumes we sold in Colombia using each transportation method for each of the three years ended December 31, 2021:

	Year Ended December 31,		
	2021	2020	2019
Volume transported through pipelines	**12 %**	4 %	1 %
Volume sold at wellhead	**34 %**	48 %	51 %
Volume transported via truck to pipelines	**54 %**	48 %	48 %
	100 %	100 %	100 %

Volumes transported through pipelines or via trucks receive a higher realized price but incur higher transportation expenses. Volumes sold at the wellhead have the opposite effect of lower realized price, offset by lower transportation expense. We focus on maximizing operating netback[(1)] per bbl when choosing a transportation method.

Transportation expenses for the year ended December 31, 2021, increased by 7% to $11.3 million, compared with $10.5 million in 2020, as a result of higher sales volumes and lower volumes sold at wellhead during 2021. On a per bbl basis, transportation expenses increased 1% to $1.44, from $1.43 in 2020. The increase in transportation expenses per bbl was a result of lower volumes sold at the wellhead in 2021, resulting in slightly higher transportation expenses per bbl compared to the corresponding period of 2020.

Transportation expenses for the year ended December 31, 2020, decreased by 48% to $10.5 million, compared with $20.4 million in 2019, as a result of lower sales volumes and the utilization of alternative transportation routes during 2020. On a per bbl basis, transportation expenses decreased 26% to $1.43, from $1.92 in 2019. The decrease in transportation expenses per bbl was a result of the utilization of alternative transportation routes during 2020, which had a lower cost per bbl compared to the corresponding period of 2019.



[(1)]Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to "Financial and Operational Highlights - Non-GAAP measures" for a definition and reconciliation of this measure.

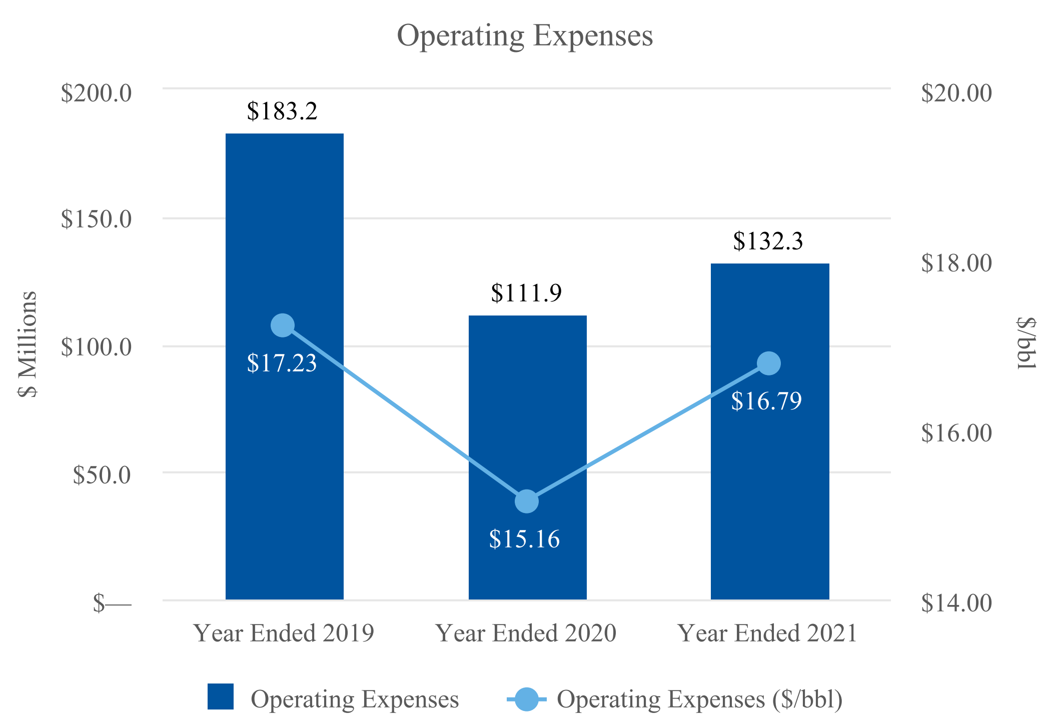
The following table shows the variance in our average realized price net of transportation expenses in Colombia for each of the three years ended December 31, 2021:

	Year Ended December 31,		
(U.S. Dollars per bbl Sales Volumes NAR)	2021	2020	2019
Average Brent price	**$ 70.95**	$ 43.21	$ 64.16
Average realized price, net of transportation expenses for the comparative period	**$ 30.80**	$ 51.76	$ 55.76
Increase (decrease) in benchmark prices	**27.74**	(20.95)	(7.53)
Decrease (increase) in quality and transportation discounts	**0.12**	(0.50)	2.68
(Increase) decrease in transportation expense	**(0.01)**	0.49	0.85
Average realized price, net of transportation expenses for the year	**$ 58.65**	$ 30.80	$ 51.76

Operating Expenses

Operating expenses for the year ended December 31, 2021, increased by 18% to $132.3 million compared to $111.9 million in 2020. On a per bbl basis, operating expenses increased by $1.63 to $16.79 compared to $15.16 in the prior year, primarily due to $1.03 per bbl higher workover activities related to changes of electric submersible pumps in Acordionero, Costayaco, and Cohembi Fields. The increased workover activities were partly related to restoring wells that failed in 2020 and were brought back online in 2021. Lower operating activities in 2020 were attributed to the shut-in of higher cost wells in response to the low oil price environment attributed to low demand for oil caused by the COVID-19 pandemic.

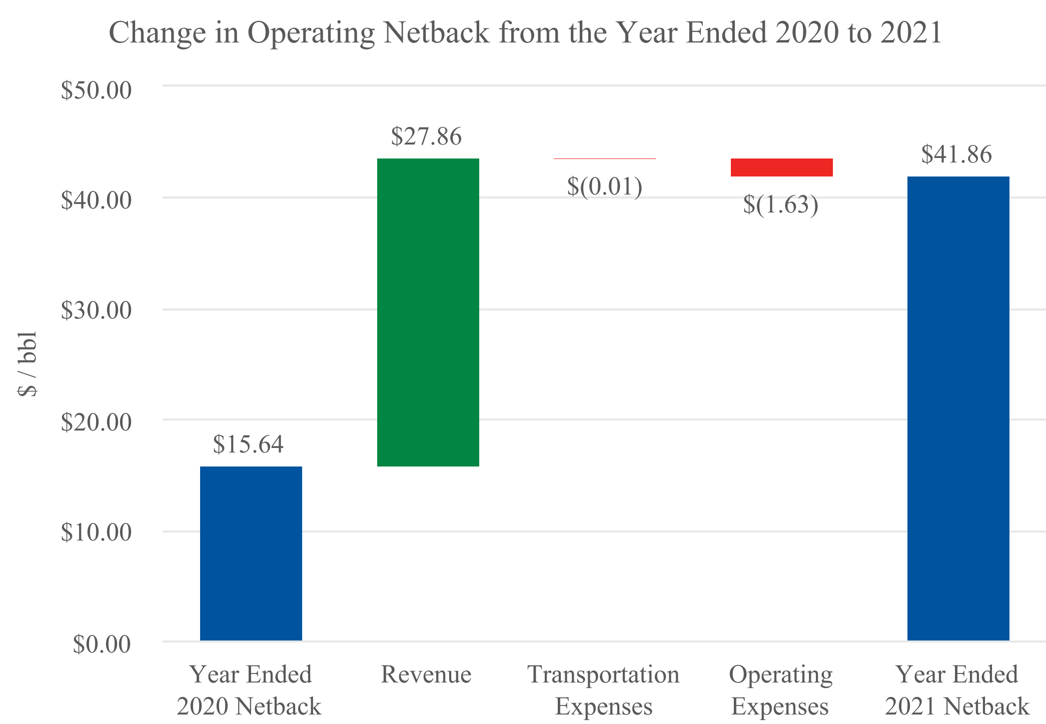
Operating expenses for the year ended December 31, 2020, decreased by 39% to $111.9 million compared to $183.2 million in 2019. On a per bbl basis, operating expenses decreased by $2.07 to $15.16 compared to $17.23 in 2019, primarily due to cost saving initiatives implemented during the first half of 2020 in response to deteriorating world oil prices and the shut-in of higher cost minor Fields for a portion of 2020. By the end of the fourth quarter of 2020, we resumed development activities throughout our portfolio at a much lower cost, including the ongoing workover operations and restart of development drilling at Acordionero, the restart of workover operations in Costayaco, and the restart of previously shut-in minor Fields.

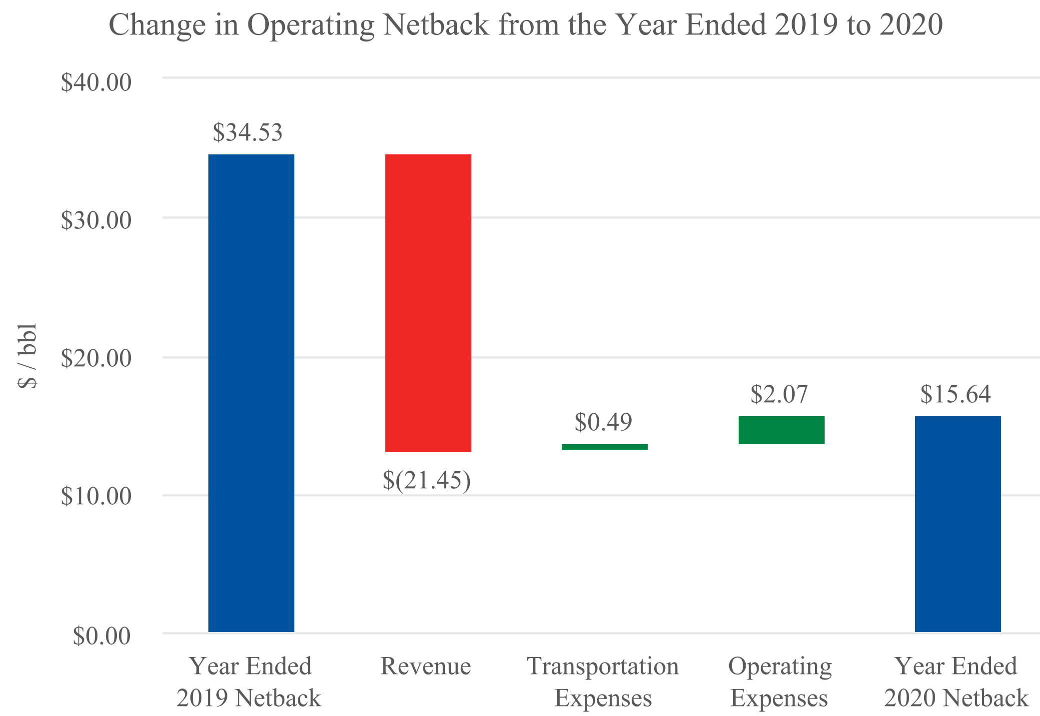


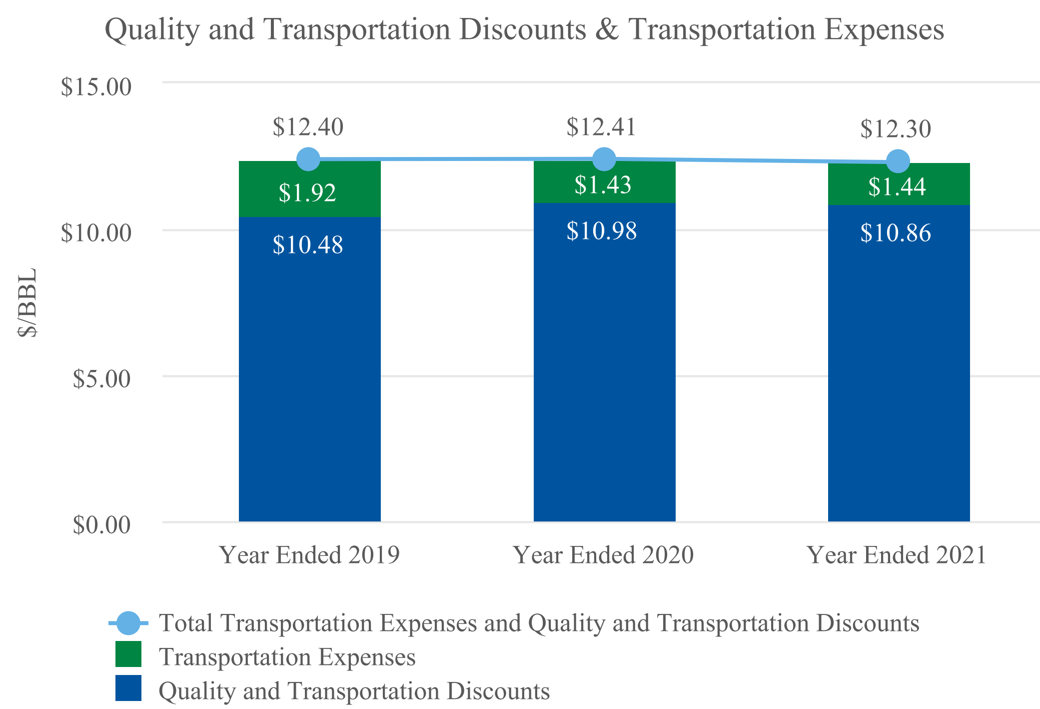
Operating Netbacks

Consolidated	Year Ended December 31, 2021	2020	2019
(Thousands of U.S. Dollars)			
Oil sales	**$ 473,722**	$ 237,838	$ 570,983
Transportation expenses	**(11,315)**	(10,543)	(20,400)
	462,407	227,295	550,583
Operating expenses	**(132,331)**	(111,888)	(183,204)
Operating netback [1]	**$ 330,076**	$ 115,407	$ 367,379
(U.S. Dollars per bbl Sales Volumes NAR)			
Brent	**$ 70.95**	$ 43.21	$ 64.16
Quality and transportation discounts	**(10.86)**	(10.98)	(10.48)
Average realized price	**60.09**	32.23	53.68
Transportation expenses	**(1.44)**	(1.43)	(1.92)
Average realized price, net of transportation expenses	**58.65**	30.80	51.76
Operating expenses	**(16.79)**	(15.16)	(17.23)
Operating netback [1]	**$ 41.86**	$ 15.64	$ 34.53

[1] Operating netback is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to "Financial and Operational Highlights - Non-GAAP measures" for a definition and reconciliation of this measure.







COVID-19 Related Costs

The COVID-19 pandemic resulted in extra operating and transportation costs related to COVID-19 health and safety preventative measures, including incremental sanitation requirements, testing, and enhanced procedures for trucking barrels and crew changes in the Field. For the year ended December 31, 2021, COVID-19 costs were $3.4 million relating to operating activities and $0.3 million to transportation activities. There were $2.7 million ($2.5 million - operating, and $0.2 million - transportation) COVID-19 related costs in 2020 and no COVID-19 related costs in 2019.

DD&A Expenses

	Year Ended December 31,		
	2021	**2020**	**2019**
DD&A Expenses, Thousands of U.S. Dollars	**$ 139,874**	$ 164,233	$ 225,033
DD&A Expenses, U.S. Dollars per bbl	**$ 17.74**	$ 22.25	$ 21.16

DD&A expenses for the year ended December 31, 2021, decreased by 15% and decreased by 20% per bbl from 2020. On a per bbl basis, the DD&A decrease in 2021 was due to higher proved reserves when compared to 2020.

DD&A expenses for the year ended December 31, 2020, decreased 27% and increased by 5% per bbl from 2019. On a per bbl basis, the DD&A increase in 2020 was due to a proportionally higher decrease in production than the decrease in overall DD&A expense compared to 2019.

Asset Impairment

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Impairment of oil and gas properties	**$ —**	$ 560,344	$ —
Impairment of inventory	**—**	4,151	—
	$ —	$ 564,495	$ —

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

For the year ended December 31, 2021, no ceiling test impairment was recorded. In accordance with GAAP, we used an average Brent price of $68.92 per bbl less corresponding differentials for the purpose of the December 31, 2021 ceiling test calculation (2020 and 2019 - $43.43 and $64.20 per bbl, respectively). There was $560.3 million of ceiling test impairment losses recorded for the year ended December 31, 2020, and no ceiling test impairment losses recorded for the year ended December 31, 2019.

For the year ended December 31, 2021, we had no oil inventory impairment losses. There was an inventory impairment losses of $4.2 million for the year ended December 31, 2020 and no inventory impairment losses for the year ended December 31, 2019.

Goodwill Impairment

The entire goodwill balance of $102.6 million was impaired during the year ended December 31, 2020. The reporting unit's carrying value exceeded its fair value due to lower forecasted commodity prices. There was no goodwill impairment for the year ended December 31, 2019.

G&A Expenses

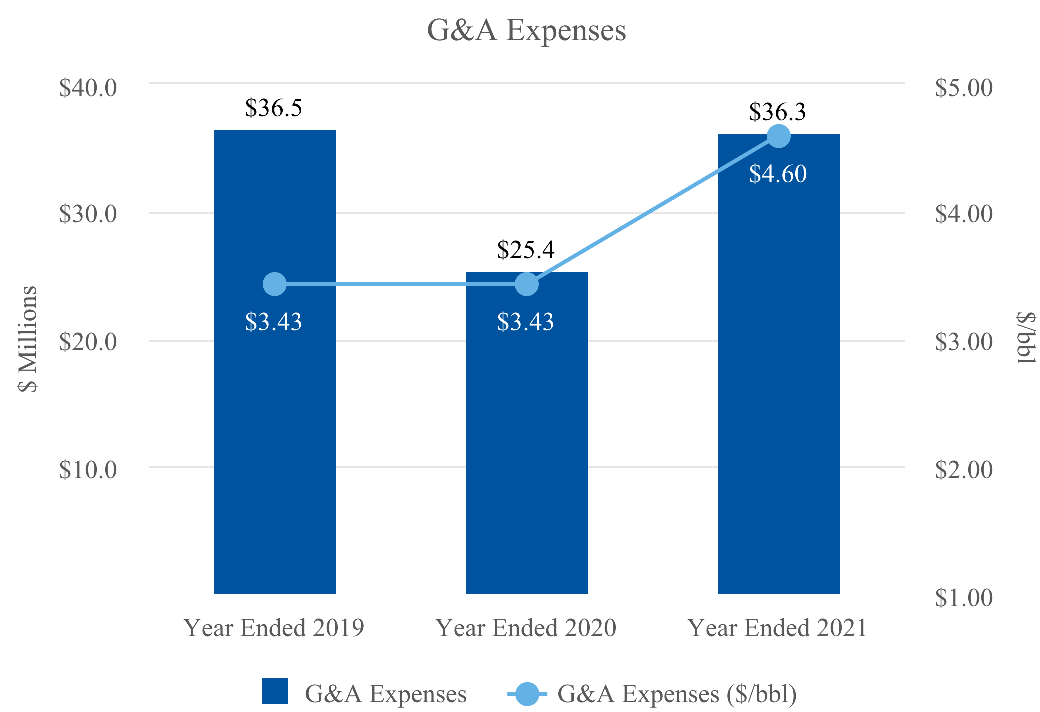
	Year Ended December 31,							
(Thousands of U.S. Dollars)		**2021**	**% change**		**2020**	**% change**		**2019**
G&A expenses before stock-based compensation	**$**	**27,867**	15	$	24,134	(31)	$	35,071
G&A stock-based compensation		**8,396**	590		1,216	(15)		1,430
G&A expenses including stock-based compensation	**$**	**36,263**	43	$	25,350	(31)	$	36,501
(U.S. Dollars Per bbl Sales Volumes NAR)								
G&A expenses before stock-based compensation	**$**	**3.53**	8	$	3.27	(1)	$	3.30
G&A stock-based compensation		**1.07**	569		0.16	23		0.13
G&A expenses including stock-based compensation	**$**	**4.60**	34	$	3.43	—	$	3.43

G&A expenses before stock-based compensation for the year ended December 31, 2021, increased 15% to $27.9 million or 8% to $3.53 per bbl compared to 2020 due to 2021 performance bonus which was slightly offset by lower travel, information technology, consulting, and legal expenses.

G&A expenses before stock-based compensation for the year ended December 31, 2020, decreased 31% to $24.1 million compared to 2019 due to headcount optimization and cost saving measures implemented in 2020. On a per bbl basis, G&A expenses before stock-based compensation decreased 1% to $3.27 compared to 2019, despite a 31% decrease in production.

G&A expenses after stock-based compensation for the year ended December 31, 2021, increased 43% to $36.3 million or 34% to $4.60 per bbl for the same reason mentioned above, as well as higher stock-based compensation costs as a result of higher share price when compared to 2020.

G&A expenses after stock-based compensation costs for the year ended December 31, 2020, decreased 31% to $25.4 million due to headcount optimization and cost savings measures implemented in 2020, as well as a lower stock-based compensation as a result of lower share price when compared to 2019. On a per bbl basis, G&A expenses after stock-based compensation were comparable to 2019.



Foreign Exchange Losses

For the years ended December 31, 2021, 2020, and 2019, we had foreign exchange losses of $20.5 million, $4.2 million, and $0.6 million, respectively. The main sources of foreign exchange losses are the revaluation of taxes receivable and payable, deferred tax assets and and Prepaid Equity Forward ("PEF"). Under GAAP, income taxes, deferred taxes, and PEF are considered monetary assets and liabilities and require translation from local currency to U.S. dollar functional currency at each balance sheet date.

The following table presents the change in the Colombian peso and Canadian dollar against the U.S. dollar for the last three years ended December 31, 2021:

	Year Ended December 31,		
	2021	**2020**	**2019**
Change in the Colombian peso against the U.S. dollar	**weakened by 16 %**	weakened by 5 %	weakened by 1 %
Change in the Canadian dollar against the U.S. dollar	**consistent — %**	strengthened by 2 %	strengthened by 5 %

Financial Instruments Gains or Losses

The following table presents the nature of our financial instruments gains or losses for each of the three years ended December 31, 2021:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Commodity price derivative loss (gain)	**$ 48,723**	$ (220)	$ 3,642
Foreign currency derivative loss	**115**	3,155	27
	48,838	2,935	3,669
Unrealized investment loss (gain)	**2,032**	46,883	(49,884)
Loss on sale of investment	**1,355**	—	—
Financial instruments (gain) loss	**(18)**	1,164	—
	$ 3,369	$ 48,047	$ (49,884)

For the year ended December 31, 2021, we had an unrealized investment loss of $2.0 million (2020 - unrealized investment loss of $46.9 million; 2019 - unrealized investment gain of $49.9 million) related to the revaluation of our investment in PetroTal Corp. ("PetroTal"). During the year ended December 31, 2021, we disposed 100% of our interest in PetroTal for a cash consideration of $43.1 million and incurred a loss on sale of $1.4 million.

Income Tax Expense and Recovery

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Income (loss) before income taxes	**$ 23,136**	$ (853,361)	$ 95,975
Current income tax expense	**$ 4,479**	$ 754	$ 17,058
Deferred income tax (recovery) expense	**(23,825)**	(76,148)	40,227
Total income tax (recovery) expense	**$ (19,346)**	$ (75,394)	$ 57,285
Effective tax rate	**(84)%**	9 %	60 %

Current income tax expense for the year ended December 31, 2021, was $4.5 million (2020 - $0.8 million; 2019 - $17.1 million). Current income tax expense increased for the year ended December 31, 2021, compared to 2020, as a result of capital gain tax from internal restructuring in Colombia.

The deferred income tax recovery of $23.8 million for the year ended December 31, 2021, was mainly a result of the release of the valuation allowance in Colombia, which was partially offset by excess tax depreciation compared with accounting depreciation and the use of tax losses to offset taxable income in Colombia. The deferred income tax recovery of $76.1 million for the year ended December 31, 2020, was primarily a result of an impairment write-down in Colombia, which was partially offset by Colombian tax losses that were fully offset by a valuation allowance. The deferred income tax expense of $40.2 million for the year ended December 31, 2019, was primarily a result of excess tax depreciation compared to accounting depreciation in Colombia.

Our effective tax rate was (84)% for the year ended December 31, 2021, compared with 9% in 2020. The decrease in the effective tax rate was primarily due to non-deductible goodwill impairment in 2020 and a decrease in the valuation allowance, foreign currency translation adjustment, the impact of foreign taxes, other permanent differences, and non-deductible investment loss on PetroTal. These were slightly offset by an increase in stock based compensation costs and non-deductible third party royalties in Colombia.

Our effective tax rate was 9% for the year ended December 31, 2020, compared with 60% in 2019. The decrease in the effective tax rate was primarily due to an increase in valuation allowance, increase in foreign currency translation adjustment, goodwill impairment, and impact of foreign taxes.

The difference between our effective tax rate of (84)% for the year ended December 31, 2021, and the 31% Colombian statutory rate was primarily due to a decrease in the valuation allowance and other permanent differences, which were partially offset by an increase in foreign currency translation adjustment, foreign taxes, stock based compensation costs, non-deductible third party royalties in Colombia, and non-deductible investment loss (PetroTal).

The difference between our effective tax rate of 9% for the year ended December 31, 2020, and the 32% Colombian statutory rate was primarily due to an increase in the valuation allowance, foreign currency translation adjustment, non-deductible goodwill impairment, and foreign taxes.

The difference between our effective tax rate of 60% for the year ended December 31, 2019, and the 33% Colombian statutory rate was primarily due to an increase in foreign currency translation adjustments, impact of foreign taxes, other permanent differences, valuation allowance, and non-deductible third party royalties in Colombia. These are partially offset by a non-taxable investment gain.

Our estimated tax pools at December 31, 2021, were as follows:

(Thousands of U.S. Dollars)	**2021**
Colombia	
Non-capital losses and other tax credits	$ 102,423
Depletable and depreciable assets	771,546
Total tax pools and credits	**$ 873,969**

Net Loss and Funds Flow From Operations (a Non-GAAP Measure)

(Thousands of U.S. Dollars)	Fourth quarter 2021 compared with third quarter 2021	% change	Fourth quarter 2021 compared with fourth quarter 2020	% change	Year ended December 31, 2021 compared with year ended December 31, 2020	% change
Net income (loss) for the comparative period	$ 35,007		$ (47,871)		$ (777,967)	
Increase (decrease) due to:						
Sales volumes	(319)		14,161		16,243	
Prices	11,287		67,333		219,641	
Expenses:						
Cash operating expenses	(2,141)		(12,493)		(20,443)	
Transportation	154		(873)		(772)	
COVID-19 related costs	322		482		(1,015)	
Cash G&A, excluding stock-based compensation expense	(3,029)		(2,991)		(3,733)	
Severance	—		—		—	
Interest, net of amortization of debt issuance costs	802		1,186		(57)	
Realized foreign exchange (loss) gain	(534)		1,435		315	
Settlement of financial instruments	(6,054)		(8,290)		(63,301)	
Other gain (loss)	—		402		(1,557)	
Current taxes	(4,493)		(4,299)		(3,725)	
Net lease payments	39		128		21	
Interest income	—		—		(345)	
Net change in funds flow from operations [(1)] from comparative period	(3,966)		56,181		141,272	
Expenses:						
Depletion, depreciation and accretion	(3,519)		(8,459)		24,359	
Goodwill impairment	—		—		102,581	
Asset impairment	—		57,402		564,495	
Deferred tax	59,589		37,282		(52,323)	
Amortization of debt issuance costs	(220)		(276)		(184)	
Loss on convertible notes	—		—		—	
Net lease payments	(39)		(128)		(21)	
Stock-based compensation	(746)		124		(7,180)	
Other non-cash (loss) gain	(44)		(44)		1,982	
Financial instruments (loss) gain, net of financial instruments settlements	(22,069)		(9,689)		62,076	
Unrealized foreign exchange	(1,469)		(21,998)		(16,608)	
Net change in net income	27,517		110,395		820,449	
Net income for the current period	$ 62,524	79 %	$ 62,524	231 %	$ 42,482	105 %

[(1)] Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to "Financial and Operational Highlights - Non-GAAP measures" for a definition and reconciliation of this measure.

2022 Work Program and Capital Expenditures

Our Colombian operation represents 100% of our production and approximately 90% of our 2022 capital budget, with the remainder allocated to exploration activities in Ecuador.

The table below shows the break-down of our 2022 capital program:

	Number of Wells (Gross and Net)	2022 Capital Budget ($ million)
Colombia		
Development	20 - 25	160 - 170
Exploration	4	40 -50
Ecuador		
Exploration	2 - 3	20
	26 - 32	220-240

Our base capital program for 2022 is $220 million to $240 million for exploration and development activities. Based on the mid-point of the 2022 guidance, the capital budget is forecasted to be approximately 70% directed to the development and 30% to exploration activities. Approximately 15% of the development activities included in the 2022 capital program are expected to be directed to facilities.

We expect our 2022 capital program to be fully funded by cash flows from operations. Funding this program from cash flow from operations relies in part on Brent oil prices being at least $60 per bbl for 2022.

Capital Program

Capital expenditures during the year ended December 31, 2021, were $149.9 million.

During the year ended December 31, 2021, we spud the following wells in Colombia:

	Number of Wells (Gross and Net)
Development	19.0
Service	3.0
Total	22.0

We spud 19 development and three service wells in 2021, 19 of which were drilled in the Midas Block and three in the Chaza Block. As at December 31, 2021, 18 of the development wells were producing and one was in-progress.

Liquidity and Capital Resources

	As at December 31,				
(Thousands of U.S. Dollars)	2021	% Change	2020	% Change	2019
Cash and cash equivalents	**$ 26,109**	91	$ 13,687	65	$ 8,301
Current restricted cash and cash equivalents	**$ 392**	(8)	$ 427	(17)	$ 516
Revolving credit facility	**$ 67,500**	(64)	$ 190,000	61	$ 118,000
Senior Notes	**$ 600,000**	—	$ 600,000	—	$ 600,000

We believe that our capital resources, including cash on hand, cash generated from operations, and available capacity on our credit facility, will provide us with sufficient liquidity to meet our strategic objectives, maintain current operations and execute the capital program for the next 12 months and beyond, given current oil price trends and production levels. In accordance with our investment policy, available cash balances are held in our primary cash management banks or may be invested in U.S. or Canadian government-backed federal, provincial, or state securities or other money market instruments with high credit ratings and short-term liquidity. We believe that our current financial position provides us the flexibility to respond to both internal growth opportunities and those available through acquisitions.

At December 31, 2021, we had a revolving credit facility with a syndicate of lenders with a borrowing base of $150.0 million. On December 21, 2021, we completed the semi-annual re-determination. We elected to reduce the borrowing base from $215.0 million to $150.0 million, with $125.0 million readily available and $25.0 million subject to approval by majority lenders. The maturity date of the borrowings under the revolving credit facility is November 10, 2022. The next re-determination of the borrowing base is due to occur no later than May 2022.

At December 31, 2021, the amount drawn under the revolving credit facility was $67.5 million and as of February 18, 2022, remained at $67.5 million.

Amounts drawn down under the revolving credit facility bear interest, at the Company's option, at the USD LIBOR rate plus a margin ranging from 2.90% to 4.90% (December 31, 2020 - 2.90% to 4.90%), or an alternate base rate plus a margin ranging from 1.90% to 3.90% (December 31, 2020 - 1.90% to 3.90%), in each case based on the borrowing base utilization percentage. The alternate base rate is currently the U.S. prime rate. Undrawn amounts under the revolving credit facility bear interest from 0.73% to 1.23% (December 31, 2020 - 0.73% to 1.23%) per annum, based on the average daily amount of unused commitments.

Under the terms of our credit facility, we are required to maintain compliance with the following financial covenants: limitations on the Company's ratio of debt to EBITDAX to a maximum of 4.0; limitations on the Company's ratio of Senior Secured Debt to EBITDAX to a maximum of 3.0; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5. If we fail to comply with these financial covenants, it would result in a default under the terms of the credit agreement, which could result in an acceleration of repayment of all indebtedness under our revolving credit facility. Under the terms of the credit facility, we are limited in our ability to pay any dividends to our shareholders without bank approval. As of December 31, 2021, we were in compliance with all applicable covenants.

At December 31, 2021, we had $300.0 million of 7.75% Senior Notes due 2027 (the "7.75% Senior Notes") and $300.0 million of 6.25% Senior Notes due 2025 (the "6.25% Senior Notes" and, together with the 7.75% Senior Notes, the "Senior Notes") The Senior Notes are fully and unconditionally guaranteed by the Company and certain subsidiaries of the Company that guarantee the revolving credit facility.

The 7.75% Senior Notes bear interest at a rate of 7.75% per year, payable semi-annually in arrears on May 23 and November 23 of each year, beginning on November 23, 2019. The 7.75% Senior Notes will mature on May 23, 2027, unless earlier redeemed or repurchased.

The 6.25% Senior Notes bear interest at a rate of 6.25% per year, payable semi-annually in arrears on February 15 and August 15 of each year, beginning on August 15, 2018. The 6.25% Senior Notes will mature on February 15, 2025, unless earlier redeemed or repurchased.

An event of default under the revolving credit facility would result in a default under the indentures governing the Senior Notes, which could allow the noteholders to require us to repurchase all of the outstanding Senior Notes.

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

At December 31, 2021, 100% of our cash and cash equivalents were held by subsidiaries outside Canada and the United States.

Derivative Positions

At December 31, 2021, we had 3,000 outstanding commodity price derivative positions and entered into additional 6000 bopd commodity derivatives subsequent to year-end for a total hedging program presented as follows:

Period and Type of Instrument	Volume, bopd	Reference	Sold Swap ($/bbl, Weighted Average)	Sold Put ($/bbl, Weighted Average)	Purchased Put ($/bbl, Weighted Average)	Sold Call ($/bbl, Weighted Average)	Premium ($/bbl, Weighted Average)
Three-way Collars: January 1, to June 30, 2022	5,000	ICE Brent	—	63.56	73.56	91.28	—
Swaps: January 1, to June 30, 2022	3,000	ICE Brent	80.41	—	—	—	—
Deferred Puts: January 1, to June 30, 2022	1,000	ICE Brent	—	—	70.00	—	4.00

Cash Flows

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

	Year Ended December 31,		
	2021	2020	2019
Sources of Cash and Cash Equivalents:			
Net income (loss)	$ **42,482**	$ (777,967)	$ 38,690
Adjustments to reconcile net income (loss) to funds flow from operations			
DD&A expenses	**139,874**	164,233	225,033
Asset impairment	**—**	564,495	—
Goodwill Impairment	**—**	102,581	—
Deferred tax (recovery) expense	**(23,825)**	(76,148)	40,227
Stock-based compensation expense	**8,396**	1,216	1,430
Amortization of debt issuance costs	**3,809**	3,625	3,376
Unrealized foreign exchange loss	**21,879**	5,271	1,803
Other non-cash loss	**44**	2,026	—
Derivative instruments loss	**48,838**	4,100	3,669
Cash settlement on derivative instruments	**(58,427)**	4,874	(3,273)
Other financial instruments loss (gain)	**3,369**	46,882	(49,884)
Loss on redemption of Convertible Notes	**—**	—	11,501
Non-cash lease expenses	**1,667**	1,951	1,806
Lease payments	**(1,621)**	(1,926)	(1,969)
Funds flow from operations [(1)]	**186,485**	45,213	272,409
Changes in non-cash operating working capital	**59,154**	36,062	—
Proceeds from issuance of Senior Notes, net of issuance costs	**—**	—	289,271
Proceeds from other debt, net of issuance costs	**—**	88,332	342,575
Changes in non-cash investing working capital	**1,431**	—	—
Proceeds from exercise of stock options	**100**	—	—
Proceeds on disposition of investment, net of transaction costs (Note 15)	**43,126**	—	—
	290,296	169,607	904,255
Uses of Cash and Cash Equivalents:			
Additions to property, plant and equipment - property acquisitions	**—**	—	(77,772)
Additions to property, plant and equipment	**(149,879)**	(96,281)	(379,314)
Repayment of debt	**(122,500)**	(17,000)	(349,219)
Lease payments	**(2,182)**	(879)	—
Proceeds from other debt, net of issuance costs	**(228)**	—	—
Changes in non-cash operating working capital	**—**	—	(93,874)
Changes in non-cash investing working capital	**—**	(48,642)	(7,851)
Cash settlement of asset retirement obligation	**(805)**	(201)	(870)
Repurchase of shares of Common Stock	**—**	—	(37,561)
Foreign exchange loss on cash and cash equivalents and restricted cash and cash equivalents	**(821)**	(156)	(1,027)
	(276,415)	(163,159)	(947,488)
Net increase (decrease) in cash and cash equivalents and restricted cash and cash equivalents	**$ 13,881**	$ 6,448	$ (43,233)

[(1)] Funds flow from operations is a non-GAAP measure which does not have any standardized meaning prescribed under GAAP. Refer to "Financial and Operational Highlights - Non-GAAP measures" for a definition and reconciliation of this measure.

Off-Balance Sheet Arrangements

As at December 31, 2021, 2020, and 2019, we had no off-balance sheet arrangements.

Contractual Obligations

The following is a schedule by year of purchase obligations, future minimum payments for firm agreements and leases that have initial or remaining non-cancelable terms in excess of one year as of December 31, 2021:

(Thousands of U.S. Dollars)	Total	2022	2023-2024	2025-2026	2027 and beyond
Revolving credit facility	$ 67,500	$ 67,500	$ —	$ —	$ —
6.25% Senior Notes	300,000	—	—	—	300,000
7.75% Senior Notes	300,000	—	—	300,000	—
Total long-term debt	667,500	67,500	—	300,000	300,000
Interest payments [1]	186,405	44,378	84,000	48,792	9,235
Facilities	31,228	5,981	11,725	11,478	2,044
Operating leases	2,889	2,163	717	9	—
Finance leases	3,686	2,532	1,154	—	—
Software and Telecommunication	1,239	413	826	—	—
Total	$ 892,947	$ 122,967	$ 98,422	$ 360,279	$ 311,279

[1] Interest payments were calculated by assuming that our revolving credit facility outstanding balance at December 31, 2021, of $67.5 million will be outstanding through the November 2022 maturity date, and our 6.25% Senior Notes and 7.75% Senior Notes will be held until their maturity dates of February 2025 and May 2027, respectively. Actual results will differ from these estimates and assumptions.

At December 31, 2021, we had provided promissory notes totaling $103.0 million (2020 - $100.6 million) to support letters of credit or surety bonds relating to work commitment guarantees contained in exploration contracts and other capital or operating requirements. These unsecured letters of credit do not utilize our revolving credit facility capacity because they are backed by local Colombian banks and Export Development Canada.

The above table does not reflect estimated amounts expected to be incurred in the future associated with the abandonment of our oil and gas properties and other long-term liabilities, as we cannot determine with accuracy the timing of such payments. Information regarding our asset retirement obligation can be found in Note 10 to the Consolidated Financial Statements, Asset Retirement Obligation, in Item 8 “Financial Statements and Supplementary Data.”

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

Climate Change

We have considered the impact of the climate events on the following items presented in this Annual Report on Form 10-K for the fiscal year ended December 31, 2021:

Impairment

We have considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in the ceiling test impairment assessment on oil and gas properties. The estimated ceiling amount of our oil and gas properties was based on proved reserves, the life of which is generally less than 16 years. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain. However, the majority of the cash flows associated with proved reserves per the 2021 reserve report should be realized prior to the potential elimination of carbon-based energy.

At December 31, 2021, a specific adjustment to the discount rate used in the ceiling test to account for the risk of the evolving demand for energy was not permitted as under the full cost accounting 10% discount rate is prescribed.

Expenditures on property, plant and equipment

During 2021, we incurred capital expenditures of $0.6 million on gas-to-power facilities in the Cohembi Field to reduce emissions principally by the recovery of natural gas and displacement of diesel. The extent of spending on projects directly linked to reducing the climate impact of our operations will vary, however, management anticipates funding projects in 2022 through cash flow from operations. From 2018 to 2020, we incurred $22.7 million on gas-to-power facilities in Acordionero Field to reduce emissions principally by the recovery of nature gas and displacement of diesel. During 2021, we converted 1.4 billion standard cubic feet of natural gas into electricity instead of being flared. In 2021, the Acordionero Field represented 53% percent of our production.

Current assets and current liabilities

These amounts are short-term in nature, and during 2021 management was not aware of any material impacts on these items related to climate change and climate events. We did not experience material credit losses on our accounts receivable during 2021.

Credit facility

We were not informed by the bank that they were withdrawing credit due specifically to climate related matters. There is risk that lenders may reduce their borrowings to the oil and gas industry. Management monitors the level of debt in the Company and will continue to adjust the capital structure to the dynamic environment.

Share capital

The evolving energy transition and general sentiment to the oil and gas industry may result in reduced access to capital markets.

Critical Accounting Policies and Estimates

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

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

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

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

We follow the full cost method of accounting for our oil and natural gas properties in accordance with SEC Regulation S-X Rule 4-10, as described in Note 2 to the Consolidated Financial Statements, Significant Accounting Policies, in Item 8 “Financial Statements and Supplementary Data.” Under the full cost method of accounting, all costs incurred in the acquisition, exploration, and development of properties are capitalized, including internal costs directly attributable to these activities. The sum of net capitalized costs, including estimated asset retirement obligations (“ARO”), and estimated future development costs to be incurred in developing proved reserves are depleted using the unit-of-production method.

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

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

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

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

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

While the quantities of proved reserves require substantial judgment, the associated prices of oil and natural gas and the applicable discount rate that are used to calculate the discounted present value of the reserves do not require judgment. The ceiling calculation dictates that a 10% discount factor be used and future net revenues are calculated using prices that represent the average of the first day of each month price for the 12-month period. Therefore, the future net revenues associated with the estimated proved reserves are not based on our assessment of future prices or costs but reflect adjustments for gravity, quality, local conditions, gathering and transportation fees, and distance from market. Estimates of standardized measure of our future cash flows from proved reserves for our December 31, 2021, ceiling tests were based on wellhead prices per bbl as of the first day of each month within that twelve month period.

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

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

For the year ended December 31, 2021, we had no ceiling test impairment losses. We had $560.3 million of ceiling test impairment losses for the year ended December 31, 2020, and no ceiling test impairment losses for the year ended December 31, 2019. We used an average Brent price of $68.92 per bbl less corresponding differentials for the purposes of the December 31, 2021 ceiling test calculations (2020 and 2019 - $43.43 and $64.20, respectively).

It is difficult to predict with reasonable certainty the amount of expected future impairment losses given the many factors impacting the asset base and the cash flows used in the prescribed U.S. GAAP ceiling test calculation. These factors include, but are not limited to, future commodity pricing, royalty rates in different pricing environments, operating costs and negotiated savings, foreign exchange rates, capital expenditures timing and negotiated savings, production and its impact on depletion and cost base, upward or downward reserve revisions as a result of ongoing exploration and development activity, and tax attributes.

Unproved Properties

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

Asset Retirement Obligations

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

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

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

Prepaid Equity Forward

We utilize prepaid equity forward ("PEF") to economically hedge, in whole or in part, our economic exposure relating to fluctuations in the market price of our Common Shares related to PSUs plan and is designated at fair value through profit or loss. The fair value of the PEF is measured based on the share price of our Common Shares. The gains and losses related to the mark-to-market of the PEF are recorded in general and administrative expense.

Leases

At inception of a contract, we assess whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At inception of a contract that contains a lease component, we allocate the consideration in the contract to each lease and non-lease component on the basis of their relative stand-alone prices. We recognize a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost, and subsequently at cost less any accumulated depreciation and impairment losses, and adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, our incremental borrowing rate. Generally, we use our incremental borrowing rate as the discount rate. The lease liability is subsequently increased by the interest cost on the lease liability and decreased by lease payments made. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, a change in the estimate of the amount expected to be payable under a residual value guarantee, or as appropriate, changes in the assessment of whether a purchase or extension option is reasonably certain to be exercised or a termination option is reasonably certain not to be exercised.

We have applied judgment to determine the lease term for contracts which include renewal or termination options. The assessment of whether we are reasonably certain to exercise such options impacts the lease term, which significantly affects the amount of lease liabilities and right-of-use assets recognized.

Revenue from Contracts with Customers

Our revenue relates to oil sales in Colombia. We recognize revenue when it transfers control of the product to a customer. This generally occurs at the time the customer obtains legal title to the product and when it is physically transferred to the delivery point agreed with the customer. Payment terms are generally within three business days following delivery of an invoice to the customer. Revenue is recognized based on the consideration specified in contracts with customers. Revenue represents our share and is recorded net of royalty payments to governments and other mineral interest owners.

We evaluate our arrangement with third parties and partners to determine if we act as a principal or an agent. In making this evaluation, our management considers if we obtain control of the product delivered, which is indicated by us having the primary responsibility for the delivery of the product, having ability to establish prices or having inventory risk. If we act in the capacity of an agent rather than as a principal in transaction, then the revenue is recognized on a net-basis, only reflecting the fee realized by us from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines owned by us are evaluated by management to determine if these originate from contracts with customers or from incidental arrangements.

In the comparative period, revenue from the production of oil and natural gas was recognized when the customer took title and assumed the risks and rewards of ownership, prices were fixed or determinable, the sale was evidenced by a contract and collection of the revenue was reasonably assured.

When determining if we acted as a principal or as an agent in transactions, management determines if we obtain control of the product. As part of this assessment, management considers detailed criteria for revenue recognition set out in ASC 606.

Allowance for credit losses

At each reporting date, we assess the expected lifetime credit losses on initial recognition of trade accounts receivable. Credit risk is assessed based on the number of days the receivable has been outstanding and the internal credit assessment of the customer. The expected loss rates are based on payment profiles over a period of 36 months prior to the period-end and the corresponding historical credit losses experienced within this period. Historical loss rates are adjusted to reflect current and forward looking economic factors of the country where we sell oil affecting the ability of the customers to settle the receivables. Trade receivables are written off when there is no reasonable expectation of recovery.

Income Taxes

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

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

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

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

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

Legal and Other Contingencies

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

Stock-Based Compensation

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

Risks and Measurement uncertainty

The outbreak of COVID-19 continued throughout 2021 including the spread of the highly transmissible Omicron variant. Worldwide economic climate continued to be volatile making accounting estimates more onerous.

Recently Adopted Accounting Pronouncements

Government Assistance (ASC 832)

In November 2021, the FASB issued ASU 2021-10, "Government Assistance". This ASU is a new topic issued to increase the transparency for government assistance transactions and disclosures due to a lack of specific authoritative guidance in GAAP. This ASU requires disclosures about government assistance in the notes to the financial statements that will provide comparable and transparent information to investors and other financial statement users to enable them to understand an entity's financial results and prospects of future cash flows. This ASU is effective for annual periods beginning after December 15, 2021. We have early adopted this ASU for our financial statements dated December 31, 2021, the adoption of which had no material impact on our disclosure requirements, balance sheet, results of operations or cash flow.

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

Commodity Price Risk

Our principal market risk relates to oil prices. Oil prices are volatile and unpredictable and influenced by concerns over world supply and demand imbalance and many other market factors outside of our control. Our revenues are from oil sales at Brent pricing and adjusted for quality.

During year ended December 31, 2021, we had 3,000 bopd commodity price derivative contracts and entered into additional 6,000 bopd subsequent to year-end, to manage the variability of cash flows associated with the forecasted sale of our oil production, reduce commodity price risk and provide a base level of cash flow in order to assure we can execute at least a portion of our capital spending. The table below provides information about our commodity price derivative contracts including the notional amounts and weighted average exchange rates by expected (contractual) maturity dates. Expected cash flows from the forward contract equaled the fair value of the contract. The information is presented in U.S. dollars because that is our reporting currency. We do not hold any of these investments for trading purposes.

Period and Type of Instrument	Volume, bopd	Reference	Sold Swap ($/bbl, Weighted Average)	Sold Put ($/bbl, Weighted Average)	Purchased Put ($/bbl, Weighted Average)	Sold Call ($/bbl, Weighted Average)	Premium ($/bbl, Weighted Average)
Three-way Collars: January 1, to June 30, 2022	5,000	ICE Brent	—	63.56	73.56	91.28	—
Swaps: January 1, to June 30, 2022	3,000	ICE Brent	80.41	—	—	—	—
Deferred Puts: January 1, to June 30, 2022	1,000	ICE Brent	—	—	70.00	—	4.00

Foreign Currency Risk

Foreign currency risk is a factor for our company but is ameliorated to a certain degree by the nature of expenditures and revenues in the countries where we operate. Our reporting currency is U.S. dollars and 100% of our revenues are related to the U.S. dollar price of Brent or WTI oil. In Colombia, we receive 100% of our revenues in U.S. dollars and the majority of our capital expenditures are in U.S. dollars or are based on U.S. dollar prices. The majority of income and value-added taxes and G&A expenses in all locations are in local currency.

Additionally, foreign exchange gains and losses result primarily from the fluctuation of the U.S. dollar to the Colombian peso and Canadian dollar ("CAD") due to our current and deferred tax assets, and taxes receivable denominated in the local currency of the Colombian foreign operations which are our monetary assets. As a result, a foreign exchange gain or loss must be calculated on conversion to the U.S. dollar functional currency. A strengthening in one Colombian peso against the U.S. dollar results in foreign exchange gain of approximately $17,000 on deferred tax asset balance and a foreign exchange gain of approximately $13,000 on taxes receivable.

During the year ended December 31, 2021, we entered into foreign currency derivative contracts to manage the variability in cash flows associated with our forecasted Colombian peso denominated costs. As at December 31, 2021 and subsequent to, we have no foreign currency forward exchange agreements.

Interest Rate Risk

Interest rate risk is the risk that future cash flows will fluctuate as a result of changes in market interest rates. We are exposed to interest rate fluctuations on our revolving credit facility, which bears floating rates of interest. At December 31, 2021, our outstanding revolving credit facility was $67.5 million (December 31, 2020 - $190.0 million). A 10% change in LIBOR would not materially impact our interest expense on debt outstanding at December 31, 2021.

Our investment objectives are focused on preservation of principal and liquidity. By policy, we manage our exposure to market risks by limiting investments to high quality bank issues at overnight rates, or U.S. or Canadian government-backed federal, provincial or state securities or other money market instruments with high credit ratings and short-term liquidity. A 10% change in interest rates would not have a material effect on the value of our investment portfolio. We do not hold any of these investments for trading purposes.

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

Report of Independent Registered Public Accounting Firm

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Gran Tierra Energy Inc. and subsidiaries (the Company) as of December 31, 2021 and 2020, the related consolidated statements of operations, changes in shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2021, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2021 and 2020, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2021, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 22, 2022 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of estimated proved oil and gas reserves on the calculations of depletion expense and the ceiling test related to Colombian oil and gas properties

As discussed in Note 2 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method on a country-by-country basis. Under such method, capitalized costs associated with Colombia are depleted over the estimated proved oil and gas reserves associated with Colombia. As discussed in Note 5 to the consolidated financial statements, for the year ended December 31, 2021, the Company recorded depletion and depreciation expense of $135.7 million. Additionally, as discussed in Note 2 and Note 6 to the consolidated financial statements, the Company performs a ceiling test calculation each quarter and for the year ended December 31, 2021 the Company did not record a ceiling test impairment. 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 reserves discounted at 10 percent, net of related tax effects, plus the lower of cost or fair value of unproved properties included in the costs being amortized. If such capitalized costs exceed the ceiling, the Company will record a write-down to the extent of such excess as a non-cash charge to net income or loss. The estimation of proved reserves, which are used in the calculations of depletion and the ceiling test, involves the expertise of independent reservoir engineering specialists who take into consideration reserve assumptions. The Company engages independent reservoir engineering specialists to estimate the proved reserves.

We identified the assessment of the impact of estimated proved reserves on the calculations of depletion expense and the ceiling test related to oil and gas properties as a critical audit matter. Changes in reserve assumptions could have had a significant impact on the calculations of depletion expense and the ceiling tests. A high degree of auditor judgment was required in evaluating the proved reserves, and related reserve assumptions, which were an input to the calculations of depletion expense and the ceiling tests.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter, including controls over the calculation of depletion expense and the ceiling test and controls over the estimation of the proved reserves, including the reserve assumptions. We assessed the calculations of depletion expense and the ceiling test for compliance with regulatory standards. We evaluated the competence, capabilities and objectivity of the independent reservoir engineering specialists engaged by the Company, who estimated the proved reserves. We evaluated the methodology used by the independent reservoir engineering specialists to estimate the proved reserves for compliance with regulatory standards. We compared the Company’s 2021 actual production, operating, royalty and capital costs to those estimates used in the prior year’s estimate of the proved reserves to assess the Company’s ability to accurately forecast. We assessed the estimates of forecasted production and forecasted operating, royalty and capital cost assumptions used in the estimate of the proved reserves by comparing them to historical results.

We have served as the Company’s auditor since 2018.

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 22, 2022

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

	Year Ended December 31,		
	2021	**2020**	**2019**
OIL SALES (NOTE 11)	**$ 473,722**	$ 237,838	$ 570,983
EXPENSES			
Operating	**132,331**	111,888	183,204
Transportation	**11,315**	10,543	20,400
COVID-19 related costs (Note 12)	**3,694**	2,679	—
Depletion, depreciation and accretion (Note 5 and 10)	**139,874**	164,233	225,033
Goodwill impairment (Note 6)	**—**	102,581	—
Asset impairment (Note 6)	**—**	564,495	—
General and administrative	**36,263**	25,350	36,501
Foreign exchange loss	**20,477**	4,184	627
Derivative instruments loss (Note 15)	**48,838**	2,935	3,669
Other financial instruments loss (gain) (Note 15)	**3,369**	48,047	(49,884)
Interest expense (Note 8)	**54,381**	54,140	43,268
TOTAL EXPENSES	**450,542**	1,091,075	462,818
OTHER LOSS	**(44)**	(469)	(12,886)
INTEREST INCOME	—	345	696
INCOME (LOSS) BEFORE INCOME TAXES	**23,136**	(853,361)	95,975
INCOME TAX EXPENSE (RECOVERY)			
Current (Note 13)	**4,479**	754	17,058
Deferred (Note 13)	**(23,825)**	(76,148)	40,227
	(19,346)	(75,394)	57,285
NET AND COMPREHENSIVE INCOME (LOSS)	**$ 42,482**	$ (777,967)	$ 38,690
NET INCOME (LOSS) PER SHARE			
– BASIC AND DILUTED	**$ 0.12**	$ (2.12)	$ 0.10
WEIGHTED AVERAGE SHARES OUTSTANDING - BASIC (Note 9)	***367,022,903***	*366,981,556*	*376,495,306*
WEIGHTED AVERAGE SHARES OUTSTANDING - DILUTED (Note 9)	***367,873,389***	*366,981,556*	*376,507,812*

(See notes to the consolidated financial statements)

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

	As at December 31, 2021	As at December 31, 2020
ASSETS		
Current Assets		
Cash and cash equivalents	**26,109**	13,687
Restricted cash and cash equivalents (Note 10)	**392**	427
Accounts receivable (Note 3)	**13,185**	8,044
Investment (Note 15)	**—**	48,323
Taxes receivable (Note 4)	**45,506**	49,925
Other current assets	**16,609**	13,459
Total Current Assets	**101,801**	133,865
Oil and Gas Properties (using the full cost method of accounting)		
Proved	**859,580**	797,355
Unproved	**131,865**	161,763
Total Oil and Gas Properties	**991,445**	959,118
Other capital assets	**4,352**	5,364
Total Property, Plant and Equipment (Note 5)	**995,797**	964,482
Other Long-Term Assets		
Taxes receivable (Note 4)	**17,522**	42,635
Deferred tax assets (Note 13)	**61,494**	57,318
Other long-term assets	**12,497**	3,425
Total Other Long-Term Assets	**91,513**	103,378
Total Assets	**$ 1,189,111**	$ 1,201,725
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities (Note 7)	**$ 148,694**	$ 100,784
Current portion of long-term debt (Note 8)	**66,987**	—
Derivatives (Note 15)	**2,976**	12,050
Taxes payable (Note 4)	**6,620**	—
Equity compensation award liability (Note 9 and 15)	**2,710**	805
Total Current Liabilities	**227,987**	113,639
Long-Term Liabilities		
Long-term debt (Note 8)	**587,404**	774,770
Asset retirement obligation (Note 10)	**54,525**	48,214
Equity compensation award liabilities (Note 9 and 15)	**13,718**	3,955
Other long-term liabilities	**3,397**	4,113
Total Long-Term Liabilities	**659,044**	831,052
Commitments and Contingencies (Note 14)		
Shareholders' Equity		
Common Stock (Note 9) (367,144,500 and 366,981,556 shares of Common Stock, par value $0.001 per share, issued and outstanding as at December 31, 2021, and December 31, 2020, respectively)	**10,270**	10,270
Additional paid in capital	**1,287,582**	1,285,018
Deficit	**(995,772)**	(1,038,254)
Total Shareholders' Equity	**302,080**	257,034
Total Liabilities and Shareholders' Equity	**$ 1,189,111**	$ 1,201,725

(See notes to the consolidated financial statements)

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

	Year Ended December 31,		
	2021	**2020**	**2019**
Operating Activities			
Net income (loss)	**$ 42,482**	$ (777,967)	$ 38,690
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and accretion (Note 5 and 10)	**139,874**	164,233	225,033
Goodwill Impairment (Note 6)	**—**	102,581	—
Asset impairment (Note 6)	**—**	564,495	—
Deferred tax (recovery) expense (Note 13)	**(23,825)**	(76,148)	40,227
Stock-based compensation (Note 9)	**8,396**	1,216	1,430
Amortization of debt issuance costs (Note 8)	**3,809**	3,625	3,376
Non-cash lease expenses	**1,667**	1,951	1,806
Lease payments	**(1,621)**	(1,926)	(1,969)
Unrealized foreign exchange loss	**21,879**	5,271	1,803
Derivative instruments loss (Note 15)	**48,838**	4,100	3,669
Cash settlement on derivatives instruments (Note 15)	**(58,427)**	4,874	(3,273)
Other financial instruments loss (gain) (Note 15)	**3,369**	46,882	(49,884)
Cash settlement of asset retirement obligation (Note 10)	**(805)**	(201)	(870)
Other non-cash loss	**44**	2,026	—
Loss on redemption of Convertible Notes	**—**	—	11,501
Net change in assets and liabilities from operating activities (Note 16)	**59,154**	36,062	(93,874)
Net cash provided by operating activities	**244,834**	81,074	177,665
Investing Activities			
Additions to property, plant and equipment (Note 5)	**(149,879)**	(96,281)	(379,314)
Property acquisitions (Note 5)	**—**	—	(77,772)
Proceeds on disposition of investment, net of transaction costs (Note 15)	**43,126**	—	—
Changes in non-cash investing working capital	**1,431**	(48,642)	(7,851)
Net cash used in investing activities	**(105,322)**	(144,923)	(464,937)
Financing Activities			
Proceeds from issuance of Senior Notes, net of issuance costs (Note 8)	**—**	—	289,271
Proceeds from bank debt, net of issuance costs	**(228)**	88,332	342,575
Repayment of debt	**(122,500)**	(17,000)	(349,219)
Lease payments	**(2,182)**	(879)	—
Proceeds from exercise of stock options	**100**	—	—
Repurchase of shares of Common Stock (Note 9)	**—**	—	(37,561)
Net cash (used in) provided by financing activities	**(124,810)**	70,453	245,066
Foreign exchange loss on cash and cash equivalents and restricted cash and cash equivalents	**(821)**	(156)	(1,027)
Net increase (decrease) in cash and cash equivalents and restricted cash and cash equivalents	**13,881**	6,448	(43,233)
Cash and cash equivalents and restricted cash and cash equivalents, beginning of year (Note 16)	**17,523**	11,075	54,308
Cash and cash equivalents and restricted cash and cash equivalents, end of year (Note 16)	**$ 31,404**	$ 17,523	$ 11,075
Supplemental cash flow disclosures (Note 16)			

(See notes to the consolidated financial statements)

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

	Year Ended December 31,		
	2021	**2020**	**2019**
Share Capital			
Balance, beginning of year	**$ 10,270**	$ 10,270	$ 10,290
Repurchase of Common Stock (Note 9)	**—**	—	(20)
Balance, end of year	**10,270**	10,270	10,270
Additional Paid in Capital			
Balance, beginning of year	**1,285,018**	1,282,627	1,318,048
Exercise of stock options (Note 9)	**100**	—	—
Stock-based compensation (Note 9)	**2,464**	2,391	2,120
Repurchase of Common Stock	**—**	—	(37,541)
Balance, end of year	**1,287,582**	1,285,018	1,282,627
Deficit			
Balance, beginning of year	**(1,038,254)**	(260,287)	(298,588)
Net income (loss)	**42,482**	(777,967)	38,690
Cumulative adjustment for accounting changes related to leases	**—**	—	(389)
Balance, end of year	**(995,772)**	(1,038,254)	(260,287)
Total Shareholders' Equity	**$ 302,080**	$ 257,034	$ 1,032,610

(See notes to the consolidated financial statements)

1. Description of Business

Gran Tierra Energy Inc., a Delaware corporation (the "Company" or "Gran Tierra"), is a publicly traded company focused on international oil and natural gas exploration and production with assets currently in Colombia and Ecuador.

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").

Significant accounting policies are:

Basis of Consolidation

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

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Estimated proved and probable reserves volumes and the related cash flows are determined by the independent reservoir engineering specialists and used in several of the estimates made by management in preparing these financial statements. Numerous estimates are required to be made in the reserve report, including forecasted production, forecasted operating royalty, capital cost assumptions, and in certain cases forecasted commodity prices. Significant estimates made by management include: depreciation, depletion, amortization ("DD&A") and impairment; impairment assessments of goodwill; timing of transfers from oil and gas properties not subject to depletion to the depletable base; asset retirement obligations; determining the value of the consideration transferred and the net identifiable assets acquired and liabilities assumed in connection with business combinations and determining goodwill; assessments of the likely outcome of legal and other contingencies; income taxes; stock-based compensation; and determining the fair value of derivatives. Although management believes these estimates are reasonable, changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results may differ from these estimates.

Cash and Cash Equivalents

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

Restricted Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

At each reporting date, the Company assesses the expected lifetime credit losses on initial recognition of trade accounts receivable. Credit risk is assessed based on the number of days the receivable has been outstanding and the internal credit assessment of the customer. The expected loss rates are based on payment profiles over a period of 36 months prior to the period-end and the corresponding historical credit losses experienced within this period. Historical loss rates are adjusted to reflect current and forward-looking economic factors of the country where the Company sells oil that affect the ability of the customers to settle the receivables. Trade receivables are written off when there is no reasonable expectation of recovery.

Prepaid Equity Forwards

The Company is exposed to equity price risk in relation to its long-term incentive plans. The Company utilizes prepaid equity forwards ("PEF") on the equivalent number of the Company's common shares in order to fix the future settlement cost on a portion of its cash-settled long-term incentive plans.

PEF is recorded in other long-term assets on the Company's balance sheet at fair value, with changes in fair value recognized as stock-based compensation expense in the consolidated statements of operations. The Company utilizes PEF to manage equity price risk in relation to its long-term incentive plans.

Derivatives

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

Inventory

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

Income Taxes

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

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

Oil and Gas Properties

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

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

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

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

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

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

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

Asset Retirement Obligation

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

Other Capital Assets

Other capital assets, including additions and replacements, are recorded at cost upon acquisition and include furniture, fixtures and leasehold improvement, computer equipment, automobiles and right-of-use assets for operating and finance leases. Depreciation for furniture and fixtures, computer equipment, and automobiles is provided using the straight-line method over the useful life of the asset. Leasehold improvements and right-of-use assets for operating and finance leases are depreciated on a straight-line basis over the shorter of the estimated useful life and the term of the related lease. The cost of repairs and maintenance is charged to expenses as incurred.

Leases

At the inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. At the inception of a contract that contains a lease component, the Company allocates the consideration in the contract to each lease and non-lease component on the basis of their relative stand-alone prices. The Company recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost and subsequently at cost less any accumulated depreciation and impairment losses and adjusted for certain remeasurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or, if that rate cannot be readily determined, the Company’s incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate. The lease liability is subsequently increased by the interest cost on the lease liability and decreased by lease payments made. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, a change in the estimate of the amount expected to be payable under a residual value guarantee, or as appropriate, changes in the assessment of whether a purchase or extension option is reasonably certain to be exercised or a termination option is reasonably certain not to be exercised.

The Company has applied judgment to determine the lease term for contracts which include renewal or termination options. The assessment of whether the Company is reasonably certain to exercise such options impacts the lease term, which significantly affects the amount of lease liabilities and right-of-use assets recognized.

Revenue from Contracts with Customers

The Company’s revenue relates to oil sales in Colombia. The Company recognizes revenue when it transfers control of the product to a customer. This generally occurs at the time the customer obtains legal title to the product and when it is physically transferred to the delivery point agreed with the customer. Payment terms are generally within three business days following delivery of an invoice to the customer. Revenue is recognized based on the consideration specified in contracts with customers. Revenue represents the Company's share and is recorded net of royalty payments to governments and other mineral interest owners.

The Company evaluates its arrangement with third parties and partners to determine if the Company acts as a principal or an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices, or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in the transaction, then the revenue is recognized on a net basis, only reflecting the fee realized by the Company from the transaction.

Tariffs, tolls, and fees charged to other entities for the use of pipelines owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental arrangements. When determining if the Company acted as a principal or agent in transactions, management determines if the Company obtains control of the product. As part of this assessment, management considers criteria for revenue recognition set out in ASC 606.

Stock-based Compensation

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

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

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

Foreign Currency Translation

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

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

Earnings (Loss) per Share

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

Risks and Measurement Uncertainty

The outbreak of COVID-19 continued throughout 2021 including the spread of the highly transmissible Omicron variant. Worldwide economic climate continued to be volatile making accounting estimates more onerous.

Recently Adopted Accounting Pronouncements

Government Assistance (ASC 832)

In November 2021, the FASB issued ASU 2021-10, "Government Assistance". This ASU is a new topic issued to increase the transparency for government assistance transactions and disclosures due to a lack of specific authoritative guidance in GAAP. This ASU requires disclosures about government assistance in the notes to the financial statements that will provide comparable and transparent information to investors and other financial statement users to enable them to understand an entity's financial results and prospects of future cash flows. This ASU is effective for annual periods beginning after December 15, 2021. The Company has early adopted this ASU for its financial statements dated December 31, 2021, the adoption of which had no material impact on the Company's disclosure requirements, balance sheet, results of operations or cash flow.

Recently Issued Accounting Pronouncements

Business Combinations (ASC 805)

In October 2021, the FASB issued ASU 2021-08, "Business Combinations". This ASU will improve the accounting for acquired revenue contracts with customers in a business combination by addressing diversity in practice and inconsistency related to the recognition of an acquired contract liability and payment terms and their effect on subsequent revenue recognized by the acquirer. The ASU will be effective for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. Early adoption is permitted. The Company is currently assessing the impact of this update on its consolidated financial position, results of operations or cash flows.

3. Accounts Receivable

	As at December 31,	
(Thousands of U.S. Dollars)	**2021**	**2020**
Trade	**$ 9,193**	$ 3,799
Other	**3,992**	4,245
Total Accounts Receivable	**$ 13,185**	$ 8,044

4. Taxes Receivable

The table below shows the break-down of taxes receivable, comprised of value-added tax ("VAT") and income tax receivables.

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2021**	**2020**
Taxes Receivable		
Current		
VAT Receivable	**$ 21,918**	$ 35,977
Income Tax Receivable	**23,588**	13,948
	$ 45,506	$ 49,925
Long-Term		
VAT Receivable	**$ —**	$ 28,485
Income Tax Receivable	**17,522**	14,150
	$ 17,522	$ 42,635
Taxes Payable		
Current		
VAT Payable	**$ 6,620**	$ —
Total Taxes Receivable net of Taxes Payable	**$ 56,408**	$ 92,560

The following table shows the movement of VAT and income tax receivables for the past two years:

(Thousands of U.S. Dollars)	VAT Receivable	Income Tax Receivable	Total Taxes Receivable
Balance, December 31, 2019	$ 118,646	$ 43,061	$ 161,707
Collected through direct government refunds	(40,884)	(26,471)	(67,355)
Collected through sales contracts	(46,326)	—	(46,326)
Taxes paid	43,719	14,611	58,330
Current tax expense	—	(754)	(754)
Foreign exchange loss	(10,693)	(2,349)	(13,042)
Balance, December 31, 2020	$ 64,462	$ 28,098	$ 92,560
Collected through direct government refunds	(604)	(14,228)	(14,832)
Collected through sales contracts	(105,858)	—	(105,858)
Taxes paid	63,792	36,352	100,144
Current tax expense	—	(4,479)	(4,479)
Foreign exchange loss	(6,494)	(4,633)	(11,127)
Balance, December 31, 2021	**$ 15,298**	**$ 41,110**	**$ 56,408**

5. Property, Plant and Equipment

(Thousands of U.S. Dollars)	As at December 31, 2021	2020
Oil and natural gas properties		
Proved	**$ 4,302,473**	$ 4,106,768
Unproved	**131,865**	161,763
	4,434,338	4,268,531
Other [1]	**34,943**	32,135
	4,469,281	4,300,666
Accumulated depletion, depreciation and impairment	**(3,473,484)**	(3,336,184)
	$ 995,797	$ 964,482

[1] The "other" category includes $13.9 million right-of-use assets for operating and finance leases which had a net book value of $3.9 million as at December 31, 2021 (December 31, 2020 - $11.4 million which had a net book value of $4.4 million).

Depletion and depreciation expense on property, plant and equipment for the year ended December 31, 2021, was $135.7 million (2020 - $160.8 million; 2019 - $220.8 million). A portion of depletion and depreciation expense was recorded as oil inventory in each year.

Unproved Oil and Natural Gas Properties

At December 31, 2021, unproved oil and natural gas properties consist of exploration lands held in Colombia and Ecuador. Unproved oil and natural gas properties are being held for their exploration value and are not being depleted pending determination of the existence of proved reserves. Gran Tierra will continue to assess the unproved properties over the next several years as proved reserves are established and as exploration warrants whether or not future areas will be developed. The Company expects that approximately 100% of costs not subject to depletion at December 31, 2021, will be transferred to the depletable base within the next five years.

The following is a summary of Gran Tierra's oil and natural gas properties not subject to depletion as at December 31, 2021:

(Thousands of U.S. Dollars)	Costs Incurred in 2021	2020	2019	Prior to 2019	Total
Acquisition costs - Colombia	$ —	$ —	$ —	$ 10,268	$ 10,268
Exploration costs - Colombia	2,416	9,909	36,881	63,306	112,512
Exploration costs - Ecuador	2,708	2,160	4,217	—	9,085
	$ 5,124	**$ 12,069**	**$ 41,098**	**$ 73,574**	**$ 131,865**

6. Impairment

Asset Impairment

Asset impairment for the years ended December 31, 2021, 2020 and 2019 was as follows:

(Thousands of U.S. Dollars)	Year Ended December 31, 2021	2020	2019
Impairment of oil and gas properties	**$ —**	$ 560,344	$ —
Impairment of inventory	**—**	4,151	—
	$ —	$ 564,495	$ —

(i) Oil and gas property impairment

For the year ended December 31, 2021, the Company had no ceiling test impairment losses. There was $560.3 million of ceiling test impairment losses for the year ended December 31, 2020, and no ceiling test impairment losses for the year ended December 31, 2019. The Company follows the full cost method of accounting for its oil and gas properties. Under this method, the net book value of properties on a country-by-country basis, less related deferred income taxes, may not exceed a calculated "ceiling". The ceiling is the estimated after-tax future net revenues from proved oil and gas properties, discounted at 10% per year. In calculating discounted future net revenues, oil and natural gas prices are determined using the average price for the 12 months 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. That average price is then held constant, except for fixed and determinable changes by existing contracts. Therefore, ceiling test estimates are based on historical prices discounted at 10% per year, and should not be assumed that estimates of future net revenues represent the fair market value of the Company's reserves. In accordance with GAAP, Gran Tierra used an average Brent price of $68.92 per bbl for of the December 31, 2021 ceiling test calculations (December 31, 2020, and 2019 - $43.43 and $64.20 per bbl, respectively).

The Company has considered the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in the ceiling test impairment assessment on oil and gas properties. The estimated ceiling amount of the Company's oil and gas properties was based on proved reserves, the life of which is generally less than 16 years. The ultimate period in which global energy markets can transition from carbon based sources to alternative energy is highly uncertain. However, the majority of the cash flows associated with proved reserves per the 2021 reserve report should be realized prior to the potential elimination of carbon-based energy.

At December 31, 2021, a specific adjustment to the discount rate used in the ceiling test to account for the risk of the evolving demand for energy is not permitted as under the full cost accounting 10% discount rate is prescribed.

(ii) Inventory impairment

For the year ended December 31, 2021, the Company had no inventory impairment losses. There were inventory impairment losses of $4.2 million for the year ended December 31, 2020, and no inventory impairment losses for the year ended December 31, 2019.

Goodwill Impairment

The entire goodwill balance of $102.6 million was impaired during the year ended December 31, 2020. The reporting unit's carrying value exceeded its fair value due to lower forecasted commodity prices. There was no goodwill impairment for the year ended December 31, 2019.

7. Accounts Payable and Accrued Liabilities

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2021**	**2020**
Trade	**$ 91,101**	$ 70,450
Royalties	**14,761**	1,570
Employee compensation	**4,382**	1,701
Other	**38,450**	27,063
	$ 148,694	$ 100,784

8. Debt and Debt Issuance Costs

The Company's debt at December 31, 2021 and 2020, was as follows:

	As at December 31,	
(Thousands of U.S. Dollars)	**2021**	**2020**
Current		
Revolving credit facility	**$ 67,500**	$ —
Unamortized debt issuance costs	**(513)**	—
Current portion of long-term debt	**$ 66,987**	$ —
Long Term		
6.25% Senior Notes	**$ 300,000**	$ 300,000
7.75% Senior Notes	**300,000**	300,000
Revolving credit facility	**—**	190,000
Unamortized debt issuance costs	**(14,030)**	(18,124)
Long-term lease obligation [(1)]	**1,434**	2,894
Long-term debt	**$ 587,404**	$ 774,770
Total Debt	**$ 654,391**	$ 774,770

[(1)] The current portion of the lease obligation has been included in accounts payable and accrued liabilities on the Company's balance sheet and totaled $3.3 million as at December 31, 2021 (December 31, 2020 - $3.3 million).

Senior Notes

At December 31, 2021, the Company had $300.0 million of 7.75% Senior Notes due 2027 (the "7.75% Senior Notes") and $300.0 million of 6.25% Senior Notes due 2025 (the "6.25% Senior Notes" and, together with the 7.75% Senior Notes, the "Senior Notes"). The Senior Notes are fully and unconditionally guaranteed by the Company and certain subsidiaries of the Company that guarantee the revolving credit facility.

The 7.75% Senior Notes bear interest at a rate of 7.75% per year, payable semi-annually in arrears on May 23 and November 23 of each year, beginning on November 23, 2019. The 7.75% Senior Notes will mature on May 23, 2027, unless earlier redeemed or repurchased.

Before May 23, 2023, the Company may, at its option, redeem all or a portion of the 7.75% Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a "make-whole" premium. Thereafter, the Company may redeem all or a portion of the 7.75% Senior Notes plus accrued and unpaid interest applicable to the date of the redemption at the following redemption prices: 2023 - 103.875%; 2024 - 101.938%; 2025 and thereafter - 100%.

The 6.25% Senior Notes bear interest at a rate of 6.25% per year, payable semi-annually in arrears on February 15 and August 15 of each year, beginning on August 15, 2018. The 6.25% Senior Notes will mature on February 15, 2025, unless earlier redeemed or repurchased.

Before February 15, 2022, the Company may, at its option, redeem all or a portion of the 6.25% Senior Notes at 100% of the principal amount plus accrued and unpaid interest and a make-whole premium. Thereafter, the Company may redeem all or a portion of the 6.25% Senior Notes plus accrued and unpaid interest applicable to the date of the redemption at the following redemption prices: 2022 - 103.125%; 2023 - 101.563%; 2024 and thereafter - 100%.

Credit Facility

At December 31, 2021, the Company had a revolving credit facility with a syndicate of lenders with a borrowing base of $150.0 million. On December 21, 2021, management completed the semi-annual re-determination and elected to reduce the borrowing base from $215.0 million to $150.0 million, with $125.0 million readily available and $25.0 million subject to approval by majority lenders. The maturity date of the borrowings under the revolving credit facility is November 10, 2022. The next re-determination of the borrowing base is due to occur no later than May 2022.

Under the terms of credit facility, the Company is required to maintain compliance with the following financial covenants: limitations on Company's ratio of Debt to Earnings before interest, taxes, depletion, depreciation and accretion and exploration expenses ("EBITDAX") to a maximum of 4.0; limitations on Company's ratio of Senior Secured Debt to EBITDAX to a maximum of 3.0; and the maintenance of a ratio of EBITDAX to interest expense of at least 2.5. The failure to comply with these financial covenants would cause a default under the terms of the credit agreement, resulting in an acceleration of repayment of all indebtedness under the revolving credit facility. As at December 31, 2021, the Company was in compliance with all covenants.

Amounts drawn down under the revolving credit facility bear interest, at the Company's option, at the USD LIBOR rate plus a margin ranging from 2.90% to 4.90% (December 31, 2020 - 2.90% to 4.90%), or an alternate base rate plus a margin ranging from 1.90% to 3.90% (December 31, 2020 - 1.90% to 3.90%), in each case based on the borrowing base utilization percentage. The alternate base rate is currently the U.S. prime rate. Undrawn amounts under the revolving credit facility bear interest from 0.73% to 1.23% (December 31, 2020 - 0.73% to 1.23%) per annum, based on the average daily amount of unused commitments.

The Company's revolving credit facility is guaranteed by and secured against the assets of certain of the Company's subsidiaries (the "Credit Facility Group"). Under the terms of the credit facility, the Company is subject to certain restrictions on its ability to distribute funds to entities outside of the Credit Facility Group, including restrictions on the ability to pay dividends to shareholders of the Company.

Certain LIBOR benchmarks will no longer be published after December 31, 2021. We expect the LIBOR benchmark to be replaced with risk-free rates. The Company does not expect this change to have a material impact on the Company as U.S dollar borrowings under the credit facilities can also bear interest at the U.S. base loan rate.

Interest Expense

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Contractual interest and other financing expenses	**$ 50,572**	$ 50,515	$ 39,892
Amortization of debt issuance costs	**3,809**	3,625	3,376
	$ 54,381	$ 54,140	$ 43,268

The Company incurred debt issuance costs in connection with the issuance of the Senior Notes and its revolving credit facility. As at December 31, 2021, the balance of unamortized debt issuance costs has been presented as a direct deduction against the carrying amount of debt and is being amortized to interest expense using the effective interest method over the term of the debt.

9. Share Capital

	Shares of Common Stock
Balance, December 31, 2018	387,079,027
Shares repurchased and cancelled	(20,097,471)
Balance, December 31, 2019 and 2020	366,981,556
Options exercised	162,944
Balance, December 31, 2021	**367,144,500**

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

Equity Compensation Awards

The Company has an equity compensation program for its executives, employees, and directors. Executives and employees are given equity compensation grants that vest based on a recipient's continued employment. In the case of Performance Share Units ("PSUs"), the number of units that vest is dependent upon the achievement of specific key performance measures. Equity settled awards consist of 80% of PSUs and 20% of stock options. The Company's stock-based compensation awards outstanding as at December 31, 2021, include PSUs, deferred share units ("DSUs"), and stock options.

In accordance with the 2007 Equity Incentive Plan, as amended, the Company's Board of Directors is authorized to issue options or other rights to acquire shares of the Company's Common Stock. On June 27, 2012, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 23,306,100 shares to 39,806,100 shares. On June 2, 2021, the shareholders of Gran Tierra approved an amendment to the Company's 2007 Equity Incentive Plan, which increased the Common Stock available for issuance thereunder from 39,806,100 shares to 54,806,100 shares.

The following table provides information about PSU, DSU and stock option activity for the year ended December 31, 2021:

	PSUs	DSUs	Stock Options	
	Number of Outstanding Share Units	**Number of Outstanding Share Units**	**Number of Outstanding Stock Options**	**Weighted Average Exercise Price /Stock Option ($)**
Balance, December 31, 2020	23,273,404	4,067,897	15,444,949	$ 1.50
Granted	13,428,840	1,642,867	5,889,310	0.80
Exercised	(1,639,926)	—	(162,944)	0.62
Forfeited	(4,697,122)	—	(1,998,558)	1.14
Expired	—	—	(1,324,035)	3.17
Balance, December 31, 2021	30,365,196	5,710,764	17,848,722	$ 1.20
Vested and exercisable, at December 31, 2021			7,534,488	$ 1.66
Vested, or expected to vest, at December 31, 2021 through the life of the options			17,394,842	$ 1.21

For the year ended December 31, 2021, Stock-based compensation expense was $8.4 million (2020 - $1.2 million; 2019 - $1.4 million) and was recorded in G&A expenses.

At December 31, 2021, there was $11.8 million (December 31, 2020 - $5.9 million; December 31, 2019 - $6.7 million) of unrecognized compensation cost related to unvested PSUs and stock options to be recognized over a weighted average period of 1.6 years. The weighted average remaining contractual term of options vested, or expected to vest, at December 31, 2021, is 3.0 years.

PSUs

PSUs entitle the holder to receive, at the option of the Company, either the underlying number of shares of the Company's Common Stock upon vesting of such units or a cash payment equal to the value of the underlying shares. PSUs will cliff vest after three years, subject to the grantee's continued employment. Upon vesting, the underlying number of Common Shares or the cash payment equivalent to their value may range from nil to 200% of the number of PSU's vested, based on the Company's performance with respect to the applicable performance targets. As at December 31, 2021, 4.4 million (December

31, 2020 - 2.7 million) of PSUs had vested and will settle in cash. The performance targets for the PSUs outstanding as at December 31, 2021, were as follows:

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

ii. 2019 and 2020 awards: 25% of the award is subject to targets relating to net asset value ("NAV") of the Company per share, and NAV is based on before tax net present value discounted at 10% of proved plus probable reserves;
2021 awards: compliance with financial covenants and $20 million free cash flow (1); and

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

(1) Defined as funds flow from operations less capital expenditures before exploration expense and Short-term incentive plan.

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

DSUs

DSUs entitle the holder to receive either the underlying number of shares of the Company's Common Stock upon vesting of such units or, at the option of the Company, a cash payment equal to the value of the underlying shares. Once a DSU is vested, it is immediately settled. During the year ended December 31, 2021, DSUs were granted to directors and will vest 100% at such time the grantee ceases to be a member of the Board of Directors. The Company currently intends to settle the DSUs in cash.

Stock Options

Each stock option permits the holder to purchase one share of Common Stock at the stated exercise price. The exercise price equals the market price of a share of Common Stock at the time of grant and vest over three years. The term of the stock options granted is five years or three months after the grantee's end of service to the Company, whichever occurs first.

For the year ended December 31, 2021, 162,944 stock options were exercised, and $0.1 million cash proceeds were received (year ended December 31, 2020, and 2019, no options exercised and no cash proceeds received).

At December 31, 2021 and 2020, the weighted average remaining contractual term for outstanding and exercisable stock options was 3.0 and 3.2 years, respectively, and for exercisable stock options was 2.2 and 1.9 years, respectively.

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

	Year Ended December 31,		
	2021	**2020**	**2019**
Dividend yield (per share)	**Nil**	Nil	Nil
Volatility	**71% to 80%**	50% to 69%	48% to 54%
Weighted average volatility	**78 %**	52 %	51 %
Risk-free interest rate	**0.4% to 0.9%**	0.3% to 1.7%	1.5% to 2.5%
Expected term	**4 - 5 years**	5 years	4 - 5 years

The weighted average grant date fair value for options granted in the year ended December 31, 2021 was $0.47 (2020 - $0.29; 2019 - $0.89) per option. The weighted average grant date fair value for options vested in the year ended December 31, 2021 was $0.52 (2020 - $0.79; 2019 - $1.10) per option. The total fair value of stock options vested during year ended December 31, 2021 was $2.1 million (2020 and 2019 - $1.9 million for each year).

Weighted Average Shares Outstanding

	Year Ended December 31,		
	2021	**2020**	**2019**
Weighted average number of common shares outstanding	**367,022,903**	366,981,556	376,495,306
Shares issuable pursuant to stock options	**1,592,092**	—	87,204
Shares assumed to be purchased from proceeds of stock options	**(741,606)**	—	(74,698)
Weighted average number of diluted common shares outstanding	**367,873,389**	366,981,556	376,507,812

For the year ended December 31, 2021, 15,559,816 options were excluded from the diluted earnings (loss) per share calculation as the options were anti-dilutive (2020 - all options ; 2019 - 9,465,737 options)

10. Asset Retirement Obligation

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

	Year Ended December 31,	
(Thousands of U.S. Dollars)	**2021**	**2020**
Balance, beginning of year	**$ 48,214**	$ 43,419
Liability incurred	**4,122**	909
Settlements	**(805)**	(201)
Accretion	**4,180**	3,464
Revisions in estimated liability	**(1,186)**	623
Balance, end of year	**$ 54,525**	$ 48,214

Revisions in estimated liabilities relate primarily to changes in estimates of asset retirement costs and include, but are not limited to, revisions of estimated inflation rates, changes in property lives and the expected timing of settling asset retirement obligations. At December 31, 2021, the fair value of assets that was legally restricted for purposes of settling asset retirement obligations was $5.3 million (December 31, 2020 - $3.8 million). These assets were accounted for as restricted cash and cash equivalents on the Company's balance sheet (Note 16).

11. Revenue

All of the Company's revenue is generated from oil sales at prices that reflect the blended prices received upon shipment by the purchaser at defined sales points or are defined by contract relative to ICE Brent and adjusted for Vasconia or Castilla crude differentials, and quality and transportation discounts each month. For the year ended December 31, 2021, 100% (2020 and 2019 - 100%) of the Company's revenue resulted from oil sales and quality and transportation discounts were 15% (2020 - 25%; 2019 - 16%) of the ICE Brent price. During the year ended December 31, 2021, the Company's production was sold primarily to three major customers in Colombia (2020 and 2019 - three) equalling 66%, 19% and 12% of total sales volumes.

As at December 31, 2021, accounts receivable included nil accrued sales revenue related to December 2021 production (as at December 31, 2020, and December 31, 2019 - $0.1 million related to December production of each respective year).

12. COVID-19 Related Costs

The COVID-19 pandemic resulted in extra operating and transportation costs related to COVID-19 health and safety preventative measures, including incremental sanitation requirements and enhanced procedures for trucking barrels and crew changes in the Field. Below is a break-down of the costs:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Operating expenses	**$ 3,391**	$ 2,482	$ —
Transportation costs	**303**	197	—
COVID-19 costs	**$ 3,694**	$ 2,679	$ —

13. Taxes

The income tax expense and recovery reported differs from the amount computed by applying the statutory rate to income (loss) before income taxes for the following reasons:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Income (loss) before income taxes			
United States	**$ (31,329)**	$ (19,065)	$ (27,984)
Foreign	**54,465**	(834,296)	123,959
	23,136	(853,361)	95,975
Statutory rate [(1)]	**31 %**	32 %	33 %
Income tax expense (recovery) expected	**7,172**	(273,076)	31,672
Impact of foreign taxes	**9,723**	26,668	9,387
Foreign currency translation	**14,450**	48,734	11,527
Goodwill Impairment	**—**	32,826	—
Stock-based compensation	**1,708**	666	430
Change in valuation allowance	**(53,434)**	75,241	3,429
Non-deductible third party royalty in Colombia	**1,568**	697	2,240
Other permanent differences	**(1,058)**	5,349	6,082
Non-deductible investment loss (gain)	**525**	7,501	(7,482)
Total income tax (recovery) expense	**$ (19,346)**	$ (75,394)	$ 57,285
Effective tax rate	**(84)%**	9 %	60 %
Current income tax expense			
Foreign [(2)]	**4,479**	754	17,058
	4,479	754	17,058
Deferred income tax (recovery) expense			
Foreign	**(23,825)**	(76,148)	40,227
Total income tax (recovery) expense	**$ (19,346)**	$ (75,394)	$ 57,285

(1) The tax rate is the statutory rate in Colombia.
(2) 2021 current tax expense relates to capital gain tax from internal restructuring in Colombia.

In general, it is the Company's practice and intention to reinvest the earnings of our non-U.S. subsidiaries in such subsidiaries' operations. As of December 31, 2021, the Company has not made a provision for U.S. or additional foreign withholding taxes on the investments in foreign subsidiaries that are indefinitely reinvested. Generally, such amounts become subject to taxation upon the remittance of dividends and under certain other circumstances.

In the third quarter of 2021, the Colombia government enacted a new tax reform to replace the 2019 tax reform. The new tax reform increases the corporate tax rate to 35% as from January 1, 2022 onwards. The tax rates applied to the calculation of deferred income taxes have been adjusted to reflect this change.

The table below presents the components of the deferred tax assets as at December 31, 2021 and 2020:

(Thousands of U.S. Dollars)	As at December 31, 2021	2020
Tax benefit of operating loss carryforwards	**$ 67,134**	$ 100,616
Tax basis in excess of book basis	**16,815**	37,698
Foreign tax credits and other accruals	**91,381**	86,664
Tax benefit of capital loss carryforwards	**28,050**	27,661
Deferred tax assets before valuation allowance	**203,380**	252,639
Valuation allowance	**(141,886)**	(195,321)
Deferred tax assets	**$ 61,494**	$ 57,318

At December 31, 2021, the Company has not recognized the benefit of unused non-capital loss carryforwards of $62.1 million (2020 - $46.0 million) for federal purposes in the United States, which expire from 2030 to 2041.

At December 31, 2021, the Company has not recognized the benefit of unused non-capital loss carryforwards of $21.1 million (2020 - $33.1 million) for federal and provincial purposes in Canada, which expire from 2030 to 2040. The Company has not recognized the benefit of capital loss carry forwards of $243.9 million (2020 - $240.5 million) for federal and provincial purposes in Canada which can be carried forward indefinitely.

At December 31, 2021, the Company has recognized the benefit of unused non-capital loss carryforwards of $102.4 million (2020 - $115.6 million), out of a total of $122.0 million; and no tax credits (2020 - $1.0 million), out of a total of $1.8 million, for federal purposes in Colombia. The Company's losses of $122.0 million are entitled to a carryforward period of 12 years.

As at December 31, 2021 and 2020, Gran Tierra had no unrecognized tax benefits and related interest and penalties included in its deferred tax assets and current tax liabilities in the consolidated balance sheet. The Company does not anticipate any material changes with respect to unrecognized tax benefit within the next twelve months. The Company had no other significant interest or penalties related to taxes included in the consolidated statement of operations for the year ended December 31, 2021. The Company and its subsidiaries file income tax returns in the U.S. and certain other foreign jurisdictions. The Company is subject to income tax examinations for the tax years ended 2013 through 2021 in certain jurisdictions.

14. Commitments and Contingencies

Purchase Obligations, Firm Agreements and Leases

As at December 31, 2021, future minimum payments under non-cancelable agreements with remaining terms in excess of one year were as follows:

		Year ending December 31					
(Thousands of U.S. Dollars)	Total	2022	2023	2024	2025	2026	Thereafter
Facilities	31,228	5,981	5,970	5,755	5,739	5,739	2,044
Operating leases [1]	2,889	2,163	623	94	9	—	—
Finance leases [1]	3,686	2,532	1,154	—	—	—	—
Software and Telecommunication	1,239	413	413	413	—	—	—
	$ 39,042	$ 11,089	$ 8,160	$ 6,262	$ 5,748	$ 5,739	$ 2,044

[1] Including maintenance and operating costs.

Gran Tierra has operating leases for office spaces, vehicles, and tanks and finance leases for waterflood facilities, storage tanks and compressors.

Indemnities

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

Letters of Credit

At December 31, 2021, the Company had provided letters of credit and other credit support totaling $103.0 million (December 31, 2020 - $100.6 million) as security relating to work commitment guarantees contained in exploration contracts in Colombia and Ecuador and other capital or operating requirements.

Contingencies

Gran Tierra has several lawsuits and claims pending, including a dispute with the ANH relating to the calculation of HPR royalties. The outcome of the lawsuits and disputes cannot be predicted with certainty; Gran Tierra believes the resolution of these matters would not have a material adverse effect on the Company's consolidated financial position, results of operations, or cash flows. Gran Tierra records costs as they are incurred or become probable and determinable.

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

Financial Instruments

Financial instruments are initially recorded at fair value, defined as the price that would be received to sell an asset or paid to market participants to settle liability at the measurement date. For financial instruments carried at fair value, GAAP establishes a fair value hierarchy that prioritizes the inputs to valuation techniques used to measure fair value. This hierarchy consists of three broad levels:

- Level 1 - Inputs representing quoted market prices in active markets for identical assets and liabilities
- Level 2 - Inputs other than quoted prices included within Level 1 that are observable for the assets and liabilities, either directly or indirectly
- Level 3 - Unobservable inputs for assets and liabilities

At December 31, 2021, the Company's financial instruments recognized on the balance sheet consist of cash and cash equivalents, restricted cash and cash equivalents, accounts receivable, other long-term assets, derivatives, accounts payable and accrued liabilities, current portion of long-term debt, long-term debt, current and long-term equity compensation reward liability and other long-term liabilities. The Company uses appropriate valuation techniques based on the available information to measure the fair values of assets and liabilities.

Fair Value Measurement

The following table presents the Company's fair value measurements of its financial instruments as of December 31, 2021 and 2020:

(Thousands of U.S. Dollars)	As at December 31, 2021	2020
Level 1		
Assets		
Investment	$ —	$ 48,323
PEF(1)	**7,578**	—
	$ 7,578	$ 48,323
Liabilities		
DSUs liability - long-term(3)	**$ 4,346**	$ 1,480
6.25% Senior Notes	**273,672**	205,500
7.75% Senior Notes	**271,500**	206,865
	$ 549,518	$ 413,845
Level 2		
Assets		
Derivative asset(2)	**$ 219**	$ —
Restricted cash and cash equivalents - long-term(1)	**4,903**	3,409
	$ 5,122	$ 3,409
Liabilities		
Derivative liability	**$ 2,976**	$ 12,050
Revolving credit facility	**66,987**	188,704
PSUs liability - current	**2,710**	805
PSUs liability - long-term(3)	**9,372**	2,475
	$ 82,045	$ 204,034
Level 3		
Liabilities		
Asset retirement obligation	**$ 54,525**	$ 48,214

(1)The long-term portion of restricted cash and PEF are included in the other long-term assets on the Company's balance sheet
(2) Included in the other current assets on the Company's balance sheet
(3) Long-term DSUs and PSUs liabilities are included in the long-term equity compensation award liability on the Company's balance sheet

The fair values of cash and cash equivalents, current restricted cash and cash equivalents, accounts receivable and accounts payable and accrued liabilities approximate their carrying amounts due to the short-term maturity of these instruments.

The fair value of long-term restricted cash and cash equivalents approximate its carrying value because interest rates are variable and reflective of market rates.

Prepaid Equity Forward (PEF)

To reduce the Company's exposure to changes in the trading price of the Company's common shares on outstanding PSUs, the Company entered into PEF. At the end of the term, the counterparty will pay the Company an amount equivalent to the notional amount of the shares using the price of the Company's common shares at the valuation date. The Company has the discretion to increase or decrease the notional amount of the prepaid equity forwards or terminate the agreement early. As at December 31, 2021, the Company's PEF had a notional amount of 10.0 million shares and a fair value of $7.6 million. During the year ended December 31, 2021, the Company recorded a gain of $0.9 million on the PEF in general and administrative expenses (December 31, 2020 and 2019- nil). The fair value of PEF asset was estimated using Company's share price quoted in active markets at the end of each reporting period.

DSUs liability

The fair value of DSUs liability was estimated using Company's share price quoted in active markets at the end of each reporting period.

PSUs liability

The fair value of the PSUs liability was estimated using the inputs, such as Company's share price and PSU performance factor.

Derivative asset and derivative liability

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

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Commodity price derivative loss (gain)	**$ 48,723**	$ (220)	$ 3,642
Foreign currency derivative loss	**115**	3,155	27
Derivative instruments loss	**$ 48,838**	$ 2,935	$ 3,669
Unrealized investment loss (gain)	**$ 2,032**	$ 46,883	$ (49,884)
Loss on sale of investment	**1,355**	—	—
Financial instruments (gain) loss	**(18)**	1,164	—
Other financial instruments loss (gain)	**$ 3,369**	$ 48,047	$ (49,884)

These gains or losses are presented as financial instruments gains or losses in the consolidated statements of operations and cash flows.

During the year ended December 31, 2021, the Company sold 100% (246.1 million common shares) of its interest in PetroTal Corp. ("PetroTal") for cash proceeds net of transaction costs of $43.1 million, resulting in a loss on sale of $1.4 million. As at December 31, 2021, Gran Tierra no longer holds an investment in the common shares of PetroTal.

Revolving credit facility and Senior Notes

Financial instruments not recorded at fair value at December 31, 2021, include the Senior Notes and the Revolving Credit Facility (Note 8).

The fair value of the Revolving Credit Facility approximates its carrying value. The fair value of the Revolving Credit Facility is estimated based on the amount the Company would have to pay a third party to assume the debt, including the credit spread for the difference between the issue rate and the period-end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the debt to new issuances (secured or unsecured) and secondary trades of similar size and credit statistics for public and private debt.

At December 31, 2021, the carrying amounts of the 6.25% Senior Notes and 7.75% Senior Notes were $294.0 million and $292.0 million, respectively, which represents the aggregate principal amounts less unamortized debt issuance costs, and the fair values were $273.7 million and $271.5 million.

Asset retirement obligation

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

Commodity Price Risk

The Company may at time utilize commodity price derivatives to manage the variability in cash flows associated with the forecasted sale of its oil production, reduce commodity price risk and provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending. As at December 31, 2021, the Company had 3,000 bopd outstanding commodity price derivative positions and entered into additional 6,000 bopd commodity derivatives subsequent to year-end for a total hedging program presented as follows:

Period and Type of Instrument	Volume, bopd	Reference	Sold Swap ($/bbl, Weighted Average)	Sold Put ($/bbl, Weighted Average)	Purchased Put ($/bbl, Weighted Average)	Sold Call ($/bbl, Weighted Average)	Premium ($/bbl, Weighted Average)
Three-way Collars: January 1, to June 30, 2022	5,000	ICE Brent	—	63.56	73.56	91.28	—
Swaps: January 1, to June 30, 2022	3,000	ICE Brent	80.41	—	—	—	—
Deferred Puts: January 1, to June 30, 2022	1,000	ICE Brent	—	—	70.00	—	4.00

Foreign Exchange Risk

The Company is exposed to foreign exchange risk in relation to its Colombian operations predominantly in operating costs, general and administrative costs and transportation costs. To mitigate exposure to fluctuations in foreign exchange, the Company may enter into foreign currency exchange derivatives. As at December 31, 2021 the Company had no outstanding foreign currency exchange derivative positions.

Unrealized foreign exchange gains and losses primarily result from fluctuation of the U.S. dollar to the Colombian peso and Canadian dollar due to Gran Tierra's current and deferred tax assets and taxes receivable, which are monetary assets and liabilities mainly denominated in the local currencies. As a result, foreign exchange gains and losses must be calculated on conversion to the U.S. dollar functional currency. A strengthening in one Colombian peso against the U.S. dollar results in foreign exchange gain of approximately $17,000 on deferred tax asset balance and a foreign exchange gain of approximately $13,000 on taxes receivable. This effect was calculated based on the Company's December 31, 2021, deferred tax assets and taxes receivable.

For the years ended December 31, 2021, 2020 and 2019 respectively, 100% of the Company's oil sales were generated in Colombia. In Colombia, the Company receives 100% of its revenues in U.S. dollars and the majority of its capital expenditures are in U.S. dollars or are based on U.S. dollar prices.

Credit Risk

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

At December 31, 2021, cash and cash equivalents and restricted cash included balances in bank accounts, term deposits and certificates of deposit, placed with financial institutions with investment grade credit ratings.

Most of the Company's accounts receivable relate to sales to customers in the oil and natural gas industry and are exposed to typical industry credit risks. The concentration of revenues in a single industry affects the Company's overall exposure to credit risk because customers may be similarly affected by changes in economic and other conditions. The Company manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis and obtaining letters of credits from customers which amounted to $18.3 million as of December 31, 2021. For the years ended December 31, 2021, 2020 and 2019, respectively, the Company had three customers which accounted for over 10% of sales.

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

16. Supplemental Cash Flow Information

The following table provides a reconciliation of cash, cash equivalents and restricted cash and cash equivalents with the Company's consolidated balance sheet that sum to the total of such amounts shown in the consolidated statements of cash flows:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Cash and cash equivalents	$ 26,109	$ 13,687	$ 8,301
Restricted cash and cash equivalents - current	392	427	516
Restricted cash and cash equivalents - long-term [1]	4,903	3,409	2,258
	$ 31,404	$ 17,523	$ 11,075

[1] The long-term portion of restricted cash is included in other long-term assets on the Company's balance sheet.

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

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Accounts receivable and other long-term assets	**$ (5,686)**	$ 27,607	$ (5,680)
Derivatives	**(5,808)**	2,302	(638)
Inventory	**(2,383)**	(2,628)	(3,179)
Other prepaids	**(199)**	(279)	583
Accounts payable and accrued and other long-term liabilities	**48,206**	(47,194)	(1,367)
Prepaid tax and taxes receivable and payable	**25,024**	56,254	(83,593)
Net changes in assets and liabilities from operating activities	**$ 59,154**	$ 36,062	$ (93,874)

The following table provides additional supplemental cash flow disclosures:

	Year Ended December 31,		
(Thousands of U.S. Dollars)	**2021**	**2020**	**2019**
Cash paid for income taxes	**$ 36,352**	$ 14,611	$ 49,196
Cash paid for interest	**$ 50,109**	$ 50,209	$ 37,767
Non-cash investing activities			
Net liabilities related to property, plant and equipment, end of year	**$ 30,142**	$ 28,711	$ 77,353

17. Subsequent Events

Subsequent to year end, the Company signed a 6-year office lease agreement for corporate office in Calgary commencing June 1, 2022. The agreement includes the average annual lease payments of $1.8 million over the term of the lease.

Supplementary Data (Unaudited)

1) Oil and Gas Producing Activities

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

A. Estimated Proved NAR Reserves

The following table sets forth Gran Tierra's estimated proved NAR reserves and total net proved developed and undeveloped reserves as of December 31, 2019, 2020, and 2021, and the changes in total net proved reserves during the three-year period ended December 31, 2021.

The net proved reserves represent management's best estimate of proved oil and natural gas reserves after royalties. Reserve estimates for each property are prepared internally each year and 100% of the reserves at December 31, 2021, have been evaluated by independent qualified reserves consultants, McDaniel & Associates Consultants Ltd.

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

	Liquids [(1)] (Mbbl)	Gas (MMcf)
Proved NAR Reserves, December 31, 2018	53,922	2,182
Purchases of reserves in place	4,495	—
Extensions	6,106	—
Technical revisions	13,336	73
Production	(10,530)	(361)
Proved NAR Reserves, December 31, 2019	67,329	1,894
Improved recoveries	961	—
Extensions	879	—
Technical revisions	2,477	(40)
Production	(6,954)	(199)
Proved NAR Reserves, December 31, 2020	64,692	1,655
Improved recoveries	2,057	—
Extensions[(2)]	7,475	—
Technical revisions	1,009	133
Production	(8,668)	(119)
Proved NAR Reserves, December 31, 2021	**66,565**	**1,669**
Proved Developed Reserves NAR, December 31, 2019	36,465	1,008
Proved Developed Reserves NAR, December 31, 2020	38,660	633
Proved Developed Reserves NAR, December 31, 2021	**41,869**	**880**
Proved Undeveloped Reserves NAR, December 31, 2019	30,864	886
Proved Undeveloped Reserves NAR, December 31, 2020	26,032	1,022
Proved Undeveloped Reserves NAR, December 31, 2021	**24,696**	**789**

[(1)] At December 31, 2021, 2020, and 2019, liquids reserves are 100% oil.
[(2)] Includes 0.5 MMBBL of extensions for Ecuador.

Changes in proved reserves during the years ended December 31, 2021, 2020 and 2019 shown in the table above primarily resulted from the following significant factors:

Improved Recoveries. Added 2.1 MMBOE of proved reserves for the year ended December 31, 2021, (2020 - 1.0 MMBOE and 2019 - nil) attributed to improved recoveries of heavy oil in the Acordionero Field.

Extensions. Added 7.5 MMBOE of proved reserves during the year ended December 31, 2021, which were attributed to extensions of 3.7 MMBOE in the Acordionero Field, 2.1 MMBOE in the Costayaco Field, 1.2 MMBOE in the Moqueta Field and 0.5 MMBOE in the Charapa Field in Ecuador (2020 - 0.9 MMBOE and 2019 - 6.1 MMBOE, due to reserve extensions in the Acordionero and Costayaco Fields).

Technical and Economic Revisions. Added 1.0 MMBOE of proved reserves during the year ended December 31, 2021, primarily related to positive technical revisions based on performance and waterflood response in the Acordionero and Costayaco Fields (2020 - 2.5 MMBOE and 2019 - 13.3 MMBOE, related to positive technical revisions in the Acordionero, Costayaco, Moqueta and Cohembi Fields based on performance and waterflood response).

Purchases of Reserves in Place. There were no additions for the years ended December 31, 2021 and 2020, respectively. For the year ended December 31, 2019, the Company added 4.5 MMBOE of proved reserves as a result of acquisition of 36.2% WI interest in the Suroriente Block and 20.0% WI in the VMM-2 Block.

B. Capitalized Costs

Capitalized costs for Gran Tierra's oil and gas producing activities consisted of the following at the end of each of the years in the two-year period ended December 31, 2021:

(Thousands of U.S. Dollars)	Proved Properties	Unproved Properties	Accumulated Depletion, Depreciation and Impairment	Net Capitalized Costs
Balance, December 31, 2021	**$ 4,302,473**	**$ 131,865**	**$ (3,442,893)**	**$ 991,445**
Balance, December 31, 2020	$ 4,106,768	$ 161,763	$ (3,309,413)	$ 959,118

C. Costs Incurred

The following table presents costs incurred for Gran Tierra’s oil and gas property acquisitions and exploration and development for the respective years:

(Thousands of U.S. Dollars)		**Total**
Year Ended December 31, 2019		
Property acquisition costs		
Proved	$	53,650
Unproved	$	48,648
Exploration costs	$	97,648
Development costs	$	281,151
Year Ended December 31, 2020		
Property acquisition costs		
Proved	$	—
Unproved	$	—
Exploration costs	$	12,852
Development costs	$	92,773
Year Ended December 31, 2021		
Property acquisition costs		
Proved	**$**	**—**
Unproved	**$**	**—**
Exploration costs	**$**	**20,410**
Development costs	**$**	**142,461**

D. Results of Operations for Oil and Gas Producing Activities

(Thousands of U.S. Dollars)	Colombia
December 31, 2021	
Oil sales	**$ 473,722**
Production costs	**(143,646)**
Exploration expenses	**—**
DD&A expenses	**(139,765)**
Asset impairment	**—**
Income tax expense	**19,346**
Results of Operations	**$ 209,657**
December 31, 2020	
Oil sales	$ 237,838
Production costs	(122,431)
Exploration expenses	—
DD&A expenses	(164,013)
Asset impairment	(564,495)
Income tax expense	75,394
Results of Operations	$ (537,707)
December 31, 2019	
Oil sales	$ 570,983
Production costs	(203,604)
Exploration expenses	—
DD&A expenses	(224,045)
Asset impairment	—
Income tax expense	(53,989)
Results of Operations	$ 89,345

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

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

	Colombia	Ecuador
Twelve month period unweighted arithmetic average of the wellhead price as of the first day of each month within the twelve month period		
2021	$ 58.07	$ 62.42
2020	$ 35.33	$ —
2019	$ 54.05	$ —
Weighted average production costs		
2021	$ 15.55	$ 17.40
2020	$ 12.90	$ —
2019	$ 18.67	$ —

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

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

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

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

(Thousands of U.S. Dollars)	Colombia	Ecuador	Total
December 31, 2021			
Future cash inflows	**$ 3,880,608**	**$ 30,573**	**$ 3,911,181**
Future production costs	**(1,249,901)**	**(13,502)**	**(1,263,403)**
Future development costs	**(365,983)**	**(12,175)**	**(378,158)**
Future asset retirement obligations	**(47,580)**	**(600)**	**(48,180)**
Future income tax expense	**(514,231)**	**(1,866)**	**(516,097)**
Future net cash flows	**1,702,913**	**2,430**	**1,705,343**
10% discount	**(481,504)**	**(2,062)**	**(483,566)**
Standardized Measure of Discounted Future Net Cash Flows	**$ 1,221,409**	**$ 368**	**$ 1,221,777**
December 31, 2020			
Future cash inflows	$ 2,329,016	$ —	$ 2,329,016
Future production costs	(929,591)	—	(929,591)
Future development costs	(252,347)	—	(252,347)
Future asset retirement obligations	(43,455)	—	(43,455)
Future income tax expense	(104,311)	—	(104,311)
Future net cash flows	999,312	—	999,312
10% discount	(271,825)	—	(271,825)
Standardized Measure of Discounted Future Net Cash Flows	$ 727,487	$ —	$ 727,487
December 31, 2019			
Future cash inflows	$ 3,711,517	$ —	$ 3,711,517
Future production costs	(1,429,689)	—	(1,429,689)
Future development costs	(351,750)	—	(351,750)
Future asset retirement obligations	(46,922)	—	(46,922)
Future income tax expense	(288,088)	—	(288,088)
Future net cash flows	1,595,068	—	1,595,068
10% discount	(406,872)	—	(406,872)
Standardized Measure of Discounted Future Net Cash Flows	$ 1,188,196	$ —	$ 1,188,196

Changes in the Standardized Measure of Discounted Future Net Cash Flows

The following table summarizes changes in the standardized measure of discounted future net cash flows for Gran Tierra's proved oil and gas reserves during two years ended December 31, 2021:

(Thousands of U.S. Dollars)	2021	2020	2019
Balance, beginning of year	**$ 727,487**	$ 1,188,196	$ 1,194,460
Sales and transfers of oil and gas produced, net of production costs	**(244,486)**	(442,826)	(595,872)
Net changes in prices and production costs related to future production	**1,217,785**	(813,627)	(387,603)
Extensions, discoveries and improved recovery, less related costs	**382,423**	47,271	200,486
Previously estimated development costs incurred during the year	**(98,724)**	(150,644)	155,287
Revisions of previous quantity estimates	**(191,738)**	700,106	731,352
Accretion of discount	**72,748**	118,820	119,446
Purchases of reserves in place	**—**	—	98,244
Net change in income taxes	**(414,458)**	128,265	(92,527)
Changes in future development costs	**(229,260)**	(48,074)	(235,077)
Net increase (decrease)	**494,290**	(460,709)	(6,264)
Balance, end of year	**$ 1,221,777**	$ 727,487	$ 1,188,196

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, with the participation of 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 13a-15(b) of the Exchange Act. Based on their evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that Gran Tierra's disclosure controls and procedures were effective as of December 31, 2021, 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

Our 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. Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2021 based on the framework in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013 (the "2013 COSO Framework"). Based on this evaluation under the 2013 COSO Framework, management concluded that our internal control over financial reporting was effective as of December 31, 2021. The effectiveness of our internal control over financial reporting as of December 31, 2021 has been audited by KPMG LLP, an independent registered public accounting firm, which audited our financial statements included in this Annual Report on Form 10-K as stated in their report which appears herein.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal controls over financial reporting during the year ended December 31, 2021, that have materially affected, or are reasonably likely to materially affect our internal controls over financial reporting.

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control Over Financial Reporting

We have audited Gran Tierra Energy Inc.'s (the Company) internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2021, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2021 and 2020, the related consolidated statements of operations, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2021, and the related notes (collectively, the consolidated financial statements), and our report dated February 22, 2022 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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 of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 22, 2022

Item 9B. *Other Information*

The Board of Directors of Gran Tierra Energy Inc. has established May 4, 2022 as the date of the Company's 2022 Annual Meeting of Stockholders (the "2022 Annual Meeting") and March 8, 2022 as the record date for determining stockholders entitled to notice of, and to vote at, the 2022 Annual Meeting. The time and location of the 2022 Annual Meeting will be as set forth in the Company's proxy materials for the 2022 Annual Meeting.

PART III

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

The information required regarding our directors is incorporated herein by reference from the information contained in the section entitled "Proposal 1 - Election of Directors" in our definitive Proxy Statement for the 2022 Annual Meeting of Stockholders (our "Proxy Statement"), a copy of which will be filed with the SEC within 120 days after December 31, 2021. For information with respect to our executive officers, see "Information About Our Executive Officers" at the end of Part I of this report, following Item 4 "Mine Safety Disclosures".

The information required regarding Section 16(a) beneficial ownership reporting compliance, if applicable, is incorporated by reference from the information contained in the section entitled "Delinquent Section 16(a) Reports" 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 President and Chief Executive Officer, Director (Principal Executive Officer), and Chief Financial Officer and Executive Vice President, Finance (Principal Financial and Accounting Officer). Gran Tierra has made the Code available on its website at www.grantierra.com.

Gran Tierra intends to satisfy the public disclosure requirements regarding (1) any amendments to the Code, or (2) any waivers under the Code given to Gran Tierra's (Principal Executive Officer) and (Principal Financial and Accounting Officer) by posting such information on its website at http://www.grantierra.com/governance.html within four business days of such amendment or waiver. Information on our website is not incorporated into this Annual Report or otherwise made part of this Annual Report.

Item 11. *Executive Compensation*

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

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

Security Ownership of Certain Beneficial Owners and Management

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

The following table provides certain information with respect to securities authorized for issuance under Gran Tierra’s equity compensation plans in effect as of the end of December 31, 2021:

Plan category	(a) Number of securities to be issued upon exercise of outstanding options [1]	(b) Weighted average exercise price of outstanding options	(c) Number of securities remaining available for future issuance under equity compensation plans, excluding securities reflected in column (a) [2]
Equity compensation plans approved by security holders	17,848,722	1.20	18,333,065
Equity compensation plans not approved by security holders	—	—	—
	17,848,722	1.20	18,333.065

[1] Includes shares reserved to be issued pursuant to stock options granted pursuant to the 2007 Equity Incentive Plan (“the Plan”), which is an amendment and restatement of our 2005 Equity Incentive Plan. This does not include any shares reserved to be issued relating to performance stock units (“PSUs”), and deferred share units (“DSUs”), which may be settled in cash or in shares of our common stock at our election, and for which management's intent to cash settle is reflected in the financial statement classification of these awards as financial liabilities.

[2] In accordance with Item 201(d) of Regulation S-K, the figure in this column represents the total number of shares of our common stock remaining available for issuance under the Plan as of December 31, 2021, minus the awards reported in column (a), above. Note, pursuant to the terms of the Plan, the pool of shares available for grant thereunder is not actually reduced until an award is settled in shares of our common stock (as opposed to reducing the pool at the time of grant). At December 31, 2021, 36,075,960 shares were issued and outstanding relating to PSUs and DSUs and would represent a reduction to the securities remaining available for future issuance under the Plan if such awards were to be equity settled. Consistent with accounting treatment that reflects management's intent to cash settle, these amounts are not included in the above table as a reduction in the securities remaining available for future issuance. Pursuant to the provisions of the Plan, the number of securities remaining available for issuance is reduced by the aggregate balance of (i) stock options exercised and outstanding at a fungible factor of 1.0 shares and (ii) unit based awards at a fungible factor of 1.0 shares for each share of our common stock issued pursuant to any equity settled awards granted under the Plan. Accordingly, the number of shares available for future awards under the Plan may be different than the amount shown in this column.

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

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

(2) Financial Statement Schedules

None.

(3) Exhibits

Exhibit No.	**Description**	**Reference**
2.2	Plan of Conversion, dated October 31, 2016.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.1	Certificate of Incorporation.	Incorporated by reference to Exhibit 3.3 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.2	Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.4 to the Current Report on Form 8-K, filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
3.3	Amendment No.1 to Bylaws of Gran Tierra Energy Inc.	Incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K, filed with the SEC on August 4, 2021 (SEC File No. 001-34018).
4.1	Subscription Receipt Agreement, dated July 8, 2016, by and between Gran Tierra Energy Inc. and Computershare Trust Company of Canada.	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K, filed with the SEC on July 14, 2016 (SEC File No. 001-34018).
4.2	Indenture related to the 6.25% Senior Notes due 2025, dated as of February 15, 2018, between Gran Tierra Energy International Holdings Ltd., the Guarantors named therein and U.S. Bank National Association.	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the SEC on February 16, 2018 (SEC File No. 001-34018).
4.3	First Supplemental Indenture related to 6.25% Senior Notes due 2025, dated as of July 23, 2019, among Gran Tierra Energy Inc., the guarantors named therein, and U.S. Bank National Association.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on August 8, 2019 (SEC File No. 001-34018).
4.4	Form of 6.25% Senior Notes due 2025.	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed with the SEC on February 16, 2018 (SEC File No. 001-34018).
4.5	Indenture related to the 7.750% Senior Notes due 2027, dated as of May 23, 2019, among Gran Tierra Energy Inc., the guarantors named therein, and U.S. Bank National Association.	Incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed with the SEC on May 23, 2019 (SEC File No. 001-34018).

4.6	First Supplemental Indenture related to 7.750% Senior Notes due 2027, dated as of July 23, 2019, among Gran Tierra Energy Inc., the guarantors named therein, and U.S. Bank.	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on August 8, 2019 (SEC File No. 001-34018).
4.10	Form of 7.750% Senior Notes due 2027 (included as Exhibit A to Exhibit 4.1).	Incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed with the SEC on May 23, 2019 (SEC File No. 001-34018).
4.11	Description of securities.	Incorporated by reference to Exhibit 4.11 to the Annual Report on Form 10-K, filed with the SEC on February 27, 2020 (SEC File No. 001-34018).
10.1	Share Purchase Agreement dated as of June 30, 2016, among Gran Tierra Energy International Holdings Ltd., Tribeca Oil & Gas Inc., Macquarie Bank Limited, Rorick Ventures Group Inc., as vendors, and PetroLatina Energy Limited.	Incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K, filed with the SEC on July 7, 2016 (SEC File No. 001-34018).
10.2	Amended and Restated 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the SEC on August 4, 2021 (SEC File No. 001-34018).
10.3	Form of Restricted Stock Unit Award Agreement Under the 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the SEC on August 7, 2013 (SEC File No. 001-34018).
10.4	Form of Option Agreement Under the 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the SEC on August 7, 2013 (SEC File No. 001-34018).
10.5	Form of Indemnity Agreement.*	Incorporated by reference to Exhibit 3.5 to the Current Report on Form 8-K filed with the SEC on November 4, 2016 (SEC File No. 001-34018).
10.6	Form of Deferred Stock Unit Award Agreement Under the 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.29 to the Annual Report on Form 10-K, filed with the SEC on February 29, 2016 (SEC File No. 001-34018).
10.7	Form of Deferred Stock Unit Grant Notice.*	Incorporated by reference to Exhibit 10.30 to the Annual Report on Form 10-K, filed with the SEC on February 29, 2016 (SEC File No. 001-34018).
10.8	Executive Employment Agreement effective May 7, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Gary Guidry.*	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.9	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Lawrence West.*	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.10	Executive Employment Agreement effective May 11, 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and James Evans.*	Incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q, filed with the SEC on November 4, 2015 (SEC File No. 001-34018).
10.11	Form of Performance Stock Unit Award Agreement Under the 2007 Equity Incentive Plan.*	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).
10.12	Form of Performance Stock Unit Grant Notice.*	Incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).
10.13	Executive Employment Agreement effective May 11 2015, between Gran Tierra Energy Canada ULC, Gran Tierra Energy Inc. and Ryan Ellson.*	Incorporated by reference to Exhibit 10.5 to the Quarterly Report on Form 10-Q, filed with the SEC on May 4, 2016 (SEC File No. 001-34018).

10.14	Credit Agreement, dated as of September 18, 2015, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on September 21, 2015 (SEC File No. 001-34018).
10.15	First Amendment to Credit Agreement, dated as of March 31, 2016, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., The Bank of Nova Scotia, and the lenders party thereto.	Incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K, filed with the SEC on April 6, 2016 (SEC File No. 001-34018).
10.16	Second Amendment to Credit Agreement, dated as of June 2, 2016, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., The Bank of Nova Scotia, and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on June 3, 2016 (SEC File No. 001-34018).
10.17	Third Amendment to Credit Agreement, dated as of August 23, 2016, by and among Gran Tierra Energy International Holdings Ltd., Gran Tierra Energy Inc., The Bank of Nova Scotia, and the lenders party thereto.	Incorporated by reference to Exhibit 10.42 to the Annual Report on Form 10-K, filed with the SEC on March 1, 2017 (SEC File No. 001-34018).
10.18	Fourth Amendment to Credit Agreement, dated as of November 16, 2016, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.43 to the Annual Report on Form 10-K, filed with the SEC on March 1, 2017 (SEC File No. 001-34018).
10.19	Fifth Amendment to Credit Agreement, dated as of February 13, 2017, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on February 15, 2017 (SEC File No. 001-34018).
10.20	Sixth Amendment to Credit Agreement, dated May 17, 2017 and effective as of June 1, 2017, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on May 19, 2017 (SEC File No. 001-34018).
10.21	Seventh Amendment to Credit Agreement, dated as of June 15, 2017, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q, filed with the SEC on August 4, 2017 (SEC File No. 001-34018).
10.22	Eighth Amendment to Credit Agreement, dated as of September 18, 2017, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on September 21, 2017 (SEC File No. 001-34018).
10.23	Ninth Amendment to Credit Agreement, dated as of November 10, 2017, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia, Societe Generale and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on November 14, 2017 (SEC File No. 001-34018).
10.24	Tenth Amendment to Credit Agreement, dated as of May 25, 2018, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q, filed with the SEC on August 2, 2018 (SEC File No. 001-34018)

10.25	Eleventh Amendment to Credit Agreement, dated as of December 20, 2018, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on December 21, 2018 (SEC File No. 001-34018)
10.26	Twelfth Amendment to Credit Agreement, dated as of May 14, 2019, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on May 15, 2019 (SEC File No. 001-34018)
10.27	Thirteenth Amendment to Credit Agreement, dated as of December 10, 2019, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on December 11, 2019 (SEC File No. 001-34018)
10.28	Fourteenth Amendment to Credit Agreement, dated as of June 1, 2020, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q, filed with the SEC on August 5, 2020 (SEC File No. 001-34018) (Certain schedules and exhibits to this agreement have been omitted pursuant to Item 601(a)(5) of Registration S-K. A copy of any omitted schedule and/or exhibit will be furnished supplementally to the SEC upon request).
10.29	Fifteenth Amendment to Credit Agreement, dated as of December 7, 2020, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Incorporated by reference to Exhibit 10.37 to the Annual Report on Form 10-K, filed with SEC on February 25, 2021 (SEC File No. 001-34018) (Certain portions of this exhibit have been redacted pursuant to Item 601(b)(10)(iv) of Regulation S-K and certain schedules and exhibits to this agreement have been omitted pursuant to Item 601(a)(5) of Registration S-K. An unredacted copy of this exhibit and a copy of any omitted schedule and/or exhibit will be furnished supplementally to the SEC upon request).
10.30	Sixteenth Amendment to Credit Agreement, dated as of December 21, 2021, by and among Gran Tierra Energy Inc., Gran Tierra Energy International Holdings Ltd., the Bank of Nova Scotia and the lenders party thereto.	Filed herewith (Certain portions of this exhibit have been redacted pursuant to Item 601(b)(10)(iv) of Regulation S-K and certain schedules and exhibits to this agreement have been omitted pursuant to Item 601(a)(5) of Registration S-K. An unredacted copy of this exhibit and a copy of any omitted schedule and/or exhibit will be furnished supplementally to the SEC upon request).
10.31	Colombian Participation Agreement, dated as of June 22, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.55 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.32	Amendment No. 1 to Colombian Participation Agreement, dated as of November 1, 2006, by and among Argosy Energy International, Gran Tierra Energy Inc., and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.56 to the Quarterly Report on Form 10-Q, filed with the SEC on August 11, 2008 (SEC File No. 001-34018).
10.33	Amendment No. 2 to Colombian Participation Agreement, dated as of July 3, 2008, between Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q/A, filed with the SEC on November 19, 2008 (SEC File No. 001-34018).
10.34	Amendment No. 3 to Participation Agreement, dated as of December 31, 2008, by and among Gran Tierra Energy Colombia, Ltd., Gran Tierra Energy Inc. and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K, filed with the SEC on January 7, 2009 (SEC File No. 001-34018).
10.35	Amendment No. 4 dated June 13, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.1 to the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2012 (SEC File No. 001-34018).

10.36	Amendment No. 5 dated February 10, 2011, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2012 (SEC File No. 001-34018).
10.37	Amendment No. 6 dated March 1, 2012, to the Colombian Participation Agreement dated June 22, 2006, between Gran Tierra Colombia Ltd and Crosby Capital, LLC.	Incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q filed with the SEC on May 7, 2012 (SEC File No. 001-34018).
10.38	Sale and Purchase Agreement for all of the issued share capital of Vetra Southeast S.L.U., dated February 20, 2019.	Incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed with the SEC on February 25, 2019 (SEC File No. 001-34018).
10.39	Sale and Purchase Agreement for Suroriente, dated February 20, 2019.	Incorporated by reference to Exhibit 10.4 to the Current Report on Form 8-K filed with the SEC on February 25, 2019 (SEC File No. 001-34018).
21.1	List of subsidiaries.	Filed herewith.
23.1	Consent of KPMG LLP.	Filed herewith.
23.2	Consent of McDaniel & Associates Consultants Ltd.	Filed herewith.
24.1	Power of Attorney.	See signature page.
31.1	Certification of Principal Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith.
31.2	Certification of Principal Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a), as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	Filed herewith.
32.1	Certification of Principal Executive Officer and Principal Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.	Furnished herewith.
99.1	Gran Tierra Energy Inc. Reserves Assessment and Evaluation of Oil and Gas Properties Corporate Summary, effective December 31, 2021.	Filed herewith.

101.INS Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document
101.SCH Inline XBRL Taxonomy Extension Schema Document
101.CAL Inline XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF Inline XBRL Taxonomy Extension Definition Linkbase Document
101.LAB Inline XBRL Taxonomy Extension Label Linkbase Document
101.PRE Inline XBRL Taxonomy Extension Presentation Linkbase Document
104. Cover Page Interactive Data File - the cover page XBRL tags are embedded within the Inline XBRL document

* Management contract or compensatory plan or arrangement.

Item 16. ***Form 10-K Summary***

None.

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 22, 2022	/s/ Gary S. Guidry
	By: Gary S. Guidry
	President and Chief Executive Officer, Director
	(Principal Executive Officer)
Date: February 22, 2022	/s/ Ryan Ellson
	By: Ryan Ellson
	Chief Financial Officer and Executive Vice President, Finance
	(Principal Financial and Accounting Officer)

POWER OF ATTORNEY

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

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

Name	Title	Date
/s/ Gary S. Guidry Gary S. Guidry	President and Chief Executive Officer, Director (Principal Executive Officer)	February 22, 2022
/s/ Ryan Ellson Ryan Ellson	Chief Financial Officer and Executive Vice President, Finance (Principal Financial and Accounting Officer)	February 22, 2022
/s/ Peter Dey Peter Dey	Director	February 22, 2022
/s/ Evan Hazell Evan Hazell	Director	February 22, 2022
/s/ Alison Redford Alison Redford	Director	February 22, 2022
/s/ Robert B. Hodgins Robert B. Hodgins	Director	February 22, 2022
/s/ Ronald Royal Ronald Royal	Director	February 22, 2022
/s/ Sondra Scott Sondra Scott	Director	February 22, 2022
/s/ David P. Smith David P. Smith	Director	February 22, 2022
/s/ Brooke Wade Brooke Wade	Director	February 22, 2022

CORPORATE INFORMATION

DIRECTORS

Gary S. Guidry
President and Chief Executive Officer

Robert Hodgins
Non-Executive Chairman

Peter Dey
Independent

Evan Hazell
Independent

Alison Redford
Independent

Ronald Royal
Independent

Sondra Scott
Independent

David Smith
Independent

Brooke Wade
Independent

EXECUTIVE MANAGEMENT

Gary S. Guidry
President and Chief Executive Officer

Ryan Ellson
Chief Financial Officer and Executive Vice President, Finance

Phillip Abraham
Vice President, Legal and Business Development

Muyiwa Akinyosoye
Vice President, Major Capital Projects

Jim Evans
Vice President, Corporate Services

Diego Perez-Claramunt
Vice President, Health Safety and Environment (HSE) & Corporate Social Responsibility (CSR)

Rodger Trimble
Vice President, Investor Relations

Lawrence West
Vice President, Exploration

Rob Will
Vice President, Asset Management

COLOMBIA MANAGEMENT

Manuel Buitrago
President and Country Manager

Chris Metcalfe
Vice President, Finance

Steve Smithinsky
Vice President, Production Operations

ECUADOR MANAGEMENT

Enrique Villalobos
President and Country Manager

Pedro Zutara
Vice President, Finance

Gran Tierra will supply a copy of this document, including financial statements and schedules, without charge, upon receiving a written request for these materials. Please submit your requests by email to: info@grantierra.com or by mail to: 900, 520-3rd Avenue SW Calgary, Alberta, Canada T2P 0R3

Gran Tierra's filings are available on the Securities and Exchange Commission website: http://www.sec.gov and Gran Tierra's reports filed with the Canadian Securities Administrators are available on SEDAR: http://www.sedar.com. UK regulatory filings are available on the National Storage Mechanism website: www.morningstar.co.uk/uk/nsm.

TRANSFER AGENT

Odyssey Trust Company
Calgary, Alberta, Canada
888-290-1175

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP
Calgary, Alberta, Canada

INDEPENDENT RESERVE AUDITORS

McDaniel International Inc.
Calgary, Alberta, Canada

INVESTOR RELATIONS

Rodger Trimble
Vice President, Investor Relations
Calgary, Alberta, Canada
403-265-3221 info@grantierra.com

GranTierra Energy

Suite 900, 520 — 3rd Avenue SW
Calgary, Alberta, Canada, T2P 0R3
www.grantierra.com